Operational and economic feasibility of 100% renewable electricity scenarios for Australia

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Operational and economic feasibility of 100% renewable electricity scenarios for Australia

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This thesis examines scenarios for 100% renewable electricity (RE100) in the Australian National Electricity Market (NEM). If Australia is to achieve its target of reducing carbon emissions to 80% below 2000 levels by 2050, one of the scenarios considered in this thesis may become reality. In this work, simulations of RE100 based on conservative assumptions have been developed that meet actual hourly electricity demand in the NEM geographic area in 2010. The system is based on commercially available technologies: concentrating solar thermal (CST) with thermal storage, wind, photovoltaics, existing hydro and biofuelled gas turbines. Estimates of renewable generation are derived from satellite observations, weather stations, and actual wind farm outputs. A genetic algorithm is used to find the lowest cost scenarios using technology costs for 2030 projected by the Australian Government in 2012. Constraints ensure that reliability is maintained with existing hydroelectricity generation and limited bioenergy consumption.

A range of RE100 systems are found to meet the NEM reliability standard. The principal challenge is meeting peak demand on winter evenings following overcast days when CST storage is only partially charged and wind speeds are low. The lowest cost scenarios are dominated by wind power, with smaller contributions from photovoltaics and dispatchable generation: CST, hydro and gas turbines. The annual cost of RE100 is compared with the projected costs in 2030 of four fossil fuel scenarios. The four scenarios, based on the least cost mix of technologies to meet 2010 demand, are: (i) a high-carbon scenario based on efficient use of coal; (ii) a medium-carbon scenario utilising gas-fired combined cycle gas turbines (CCGTs) and open cycle gas turbines (OCGTs); (iii) coal with carbon capture and storage (CCS) plus OCGT; and (iv) CCGT with CCS plus OCGT. Sensitivity analysis of the results to carbon prices, gas prices, and projected CO2 transportation and injection costs shows that only under a few combinations of costs can any of the low- or medium-carbon fossil fuel scenarios compete economically with RE100 in a carbon constrained world.

It appears possible to reliably supply the NEM using very high penetrations of available renewable energy (RE) technologies with the RE resources of Australia. Furthermore, RE100 is not necessarily more expensive than other low- or medium- carbon options to achieve deep cuts in electricity sector emissions, and offers a lower risk pathway.

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Abstract

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Acknowledgements

> *'To those who will not have the benefit of two billion years' accumulated energy reserves'*
>
> – David MacKay (2009)

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My wife Lisa and children Nicholas and Caitlin have also supported me during my candidature. Caitlin, age 3, has never known her Dad doing anything else. Nicholas thinks Dad works at the National Library of Australia. For all of its challenges, though, a PhD is a remarkably flexible occupation for a parent of young children.

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Publications arising from the thesis

Peer-reviewed journal papers

- Elliston, B., Diesendorf, M., and MacGill, I. Simulations of scenarios with 100% renewable electricity in the Australian National Electricity Market. *Energy Policy*, 45(0):606–613, 2012a **(Chapter 5)**

- Elliston, B., MacGill, I., and Diesendorf, M. Least cost 100% renewable electricity scenarios in the Australian National Electricity Market. *Energy Policy*, 59(0):270–282, 2013 **(Chapter 6)**

- Elliston, B., MacGill, I., and Diesendorf, M. Comparing least cost scenarios for 100% renewable electricity with low emission fossil fuel scenarios in the Australian National Electricity Market. *Renewable Energy*, 66(0):196–204, 2014 **(Chapter 7)**

- Turner, G. M., Elliston, B., and Diesendorf, M. Impacts on the biophysical economy and environment of a transition to 100% renewable electricity in Australia. *Energy Policy*, 54(0):288–299, 2013

Peer-reviewed conference papers

- Elliston, B. and MacGill, I. The potential role of forecasting for integrating solar generation into the Australian National Electricity Market. In *Solar 2010: proceedings of the annual conference of the Australian Solar Energy Society*, 2010

- Elliston, B., MacGill, I., and Diesendorf, M. Grid parity: A potentially misleading concept? In *Solar 2010: proceedings of the annual conference of the Australian Solar Energy Society*, 2010

- Elliston, B. Generating Australian historical weather data files to facilitate solar generation simulations. In *Solar 2011: proceedings of the annual conference of the Australian Solar Energy Society*, 2011 **(within Chapter 4)**

- Elliston, B., Diesendorf, M., and MacGill, I. Simulations of scenarios with 100% renewable electricity in the Australian National Electricity Market. In *Solar 2011: proceedings of the annual conference of the Australian Solar Energy Society*, 2011 **(Chapter 5)**

- Elliston, B., Diesendorf, M., and MacGill, I. Reliability of 100% renewable electricity in the Australian National Electricity Market. In *Proceedings of the 2012 International 100% Renewable Energy Conference*, pages 325–331, Istanbul, Turkey, 2012b **(Chapter 8)**

Other publications

- Lovegrove, K., Franklin, S., and Elliston, B. Australian Companion Guide to SAM for Concentrating Solar Power. Technical report, IT Power (Australia) Pty Ltd, Canberra, May 2013

Awards

The following awards were received during the candidature:

- Commended paper in the Australian Solar Energy Society Wal Read Student Prize (postgraduate category), Solar 2010, Canberra, Australia, December 2010.
- Best student presentation at the 1st International Conference on Energy & Meteorology, Gold Coast, Australia, November 2011.
- Joint winner in the Australian Energy Society Wal Read Student Prize (postgraduate category), Solar 2011, Sydney, Australia, December 2011.
- University of New South Wales Faculty of Science Dean's Award to Postgraduate & Honours Students for National Achievements in Research, 2011.
- Honorary mention for best student oral presentation at the 2012 Australian Meteorological and Oceanographic Society conference, Sydney, Australia, February 2012.
- Invited speaker, 2012 Frontiers of Science meeting, Australian Academy of Science, Sydney, Australia, December 2012.
- Representative of the University of New South Wales to the Universitas 21 Graduate Research Conference on Energy: Systems, Policy & Solutions, Dublin, Ireland, June 2013.
- Runner-up for best student presentation at the 2nd International Conference on Energy & Meteorology, Toulouse, France, June 2013.

Contents

List of acronyms

2DS	two degree scenario
AC	alternating current
ACT	Australian Capital Territory
AEMO	Australian Energy Market Operator
AETA	Australian Energy Technology Assessment
ARENA	Australian Renewable Energy Agency
Bureau	Bureau of Meteorology
BREE	Bureau of Resources and Energy Economics
CAES	compressed air energy storage
CAISO	California Independent System Operator
CCAM	Cubic Conformal Atmospheric Model
CCGT-CCS	combined cycle gas turbine with carbon capture and storage
CCGT	combined cycle gas turbine
CCS	carbon capture and storage
CHP	combined heat and power
CPI	Consumer Price Index
CSIRO	Commonwealth Scientific and Industrial Research Organisation

CST	concentrating solar thermal
DC	direct current
DLR	German Aerospace Center
DNI	direct normal irradiance
DNSP	distribution network service provider
EEG	Erneuerbare-Energien-Gesetz
EFOM	Energy Flow Optimisation Model
EPW	EnergyPlus Weather
ERCOT	Electric Reliability Council of Texas
EREC	European Renewable Energy Council
eRET	expanded Renewable Energy Target
ETI	evolutionary technology improvement
ETS	emissions trading system
EU	European Union
GA	genetic algorithm
GALLM	Global and Local Learning Model
GEA	Global Energy Assessment
GHI	global horizontal irradiance
GIS	Geographic Information System
HDF5	Hierarchical Data Format version 5
HSA	hot sedimentary aquifer
HVDC	high voltage direct current

IEA	International Energy Agency
IGCC	integrated gasification combined cycle
IIASA	International Institute for Applied Systems Analysis
IMAGE	Integrated Model to Assess the Global Environment
IPCC	Intergovernmental Panel on Climate Change
IRENA	International Renewable Energy Agency
ITI	incremental technology improvement
JMA	Japan Meteorological Agency
LCOE	levelised cost of energy
LULUCF	land use, land use change and forestry
MARKAL	Market Allocation
MESSAGE	Model for Energy Supply Strategy Alternatives and their General Environmental Impact
MPCCC	Multi-Party Climate Change Committee
MRET	Mandatory Renewable Energy Target
MRL	Minimum Reserve Level
Mt	megatonnes
NCI	National Computational Infrastructure
NEMMCO	National Electricity Market Management Company
NEM	National Electricity Market
NER	National Electricity Rules
NREL	National Renewable Energy Laboratory

NSW	New South Wales
NTI	no technological improvement
NTNDP	National Transmission Network Development Plan
NWM	numerical weather model
OCGT	open cycle gas turbine
OECD	Organisation for Economic Co-operation and Development
O&M	operating and maintenance
PJM	Pennsylvania-New Jersey-Maryland
ppm	parts per million
PS20	Planta Solar 20
PSH	pumped storage hydro
PSO	particle swarm optimisation
PV	photovoltaic
QNI	Queensland to New South Wales interconnector
R&D	research and development
ReEDS	Renewable Electricity Deployment Systems
RE Futures	Renewable Electricity Futures Study
REMod-D	Renewable Energy Model-Deutschland
RE	renewable energy
RE100	100% renewable electricity
SAM	System Advisor Model
SA	South Australia

SEGS Solar Electric Generating Station

SRMC short run marginal cost

SWITCH Solar, Wind, Hydro and Conventional generation and Transmission Investment

SWRF SAM Wind Resource File

TAPM The Air Pollution Model

TIAM TIMES Integrated Assessment Model

TIMES The Integrated MARKAL-EFOM System

TES thermal energy storage

TMY Typical Meteorological Year

TNSP transmission network service provider

UNSW University of New South Wales

US United States

UTC Coordinated Universal Time

VO&M variable operating and maintenance

VRE variable renewable energy

WECC Western Electricity Coordinating Council

WRF Weather and Research Forecasting

WWF World Wide Fund for Nature

WWS wind, water and sunlight

ZCB Zero Carbon Britain

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Chapter 1

Introduction

> *'A decade ago, cities, regions, and businesses aiming for 20% renewable energy were on the cutting edge. Few believed that a higher target in a few decades was an achievable goal. Anyone even suggesting a target of 100% renewable energy was a radical. Fast forward to today and in much of Europe, and increasingly in the U.S. and the developing world, 100% renewable energy goals are becoming the new normal.'*
>
> – Diane Moss (2013)

1.1 Problem statement

This thesis explores whether the Australian National Electricity Market (NEM) could operate entirely with renewable energy (RE) as one of a suite of actions to deeply cut greenhouse gas emissions in Australia. Efficiently transforming the NEM to a system with low emissions is a significant challenge, but is necessary for the protection of the climate. Until now, the idea of 100% renewable electricity has been difficult to conceive because it represents a marked departure from the way electric power systems have been traditionally designed and operated, with large, centralised, fossil-fuelled generators transmitting power to demand centres. Australia, having a highly emissions intensive electricity industry, must rapidly transition to zero carbon sources if Australia is to make its fair contribution to global emissions reductions. The International Energy Agency (2011) has observed that 80% of the total energy-related emissions permissible by 2035, in its 450 parts per million scenario, are already 'locked in' by our existing capital stock of energy infrastructure. Continuing development patterns for the next five years would then require that all subsequent energy supply be zero carbon.

The NEM is the largest electricity market in Australia, covering the states of Queensland, New South Wales (including the Australian Capital Territory), South Australia, Tasmania, and Victoria. The NEM produces around one third of total Australian greenhouse gas emissions, as the system derives around 90% of supply from bituminous coal, lignite and natural gas. Given the long life of electricity industry assets, Australian energy and climate policy must therefore now consider the potential for future low emission electricity systems based on rapid deployment of commercially available zero carbon technologies. The only zero carbon 'sources' that are commercially available and seem likely to be able to make large contributions before 2020 in the Australian context are certain RE sources (Department of Resources, Energy and Tourism 2012) and demand reduction (eg, through efficient energy use).

Other industrialised countries are moving away from high carbon polluting forms of electricity generation more aggressively than Australia. The stated renewable electricity targets of Germany (80% by 2050) and Denmark (100% by 2035) are an autonomous approach to reducing greenhouse gas emissions at the national level, simultaneously addressing other objectives such as energy independence (Lilliestam et al. 2012) and competitiveness in clean technology industries (Schreurs 2012). The European Union has committed to 20% renewable electricity for the Union by 2020, although this varies by member country. Ireland, for example, has a 40% renewable electricity target for 2020. New Zealand has a target of 90% renewable electricity by 2025, although generation in New Zealand is dominated by hydroelectricity. Australia, highly dependent on fossil fuelled electricity generation, has so far failed to envisage renewables as having the potential to contribute significantly to the energy system.

1.2 Contribution of the thesis

By answering the following research questions, this thesis contributes to our understanding of the extent to which renewable electricity may play in addressing climate change in Australia.

- If all the existing fossil-fuelled power stations in the NEM were replaced with commercially available RE, how reliable would the renewable electricity system be? Is it as reliable as the existing carbon intensive system?
- What is the economic optimal mix of RE technologies in the 100% renewable system, and what would it cost?
- How do the costs compare to plausible alternatives that achieve improved levels of climate protection, such as efficient fossil fuelled systems and fossil-fuelled systems with carbon capture and storage (CCS)? Under what conditions do 100% RE systems break-even with the various fossil-fuelled systems?

1.3 Approach

In this thesis, scenarios of future 100% renewable electricity are simulated and evaluated. The scenarios focus exclusively on electricity generation in order to model the system in adequate detail and limit the scope of the task. At the start of this research in 2010, the idea of 100% renewable electricity was very controversial in Australia and it remains so, to a lesser degree, today. An aim, therefore, was to develop a modelling approach that could credibly assess the possibility of operating the NEM entirely from RE. Assumptions were kept to a minimum and, where necessary, these were made conservatively.

The thesis models scenarios of 100% renewable electricity in the year 2010 using hour-by-hour simulations balancing electricity generation and demand using demand data and weather observations from that year. The scenarios assume no load shifting or demand reductions through energy efficiency. The potential for electrifying other sectors such as transportation, heating and cooling, or industrial processes is not considered. Conservative assumptions about the predicted future capital and operating costs of the different technologies are taken from the Australian Energy Technology Assessment, an on-going effort by the Australian Bureau of Resources and Energy Economics (BREE) to track the progress of 40 electricity generating technologies in Australia (Bureau of Resources and Energy Economics 2012a). These scenarios are valuable in demonstrating that such aggressive reductions in fossil fuel use are achievable, and to provide a vision of how the future energy system might look.

The literature evaluating 100% RE scenarios goes back several decades (Chapter 3). Earlier work has demonstrated at coarser resolution the technical feasibility of high penetration renewable electricity. Many scenario studies are now being published in the literature in regions all over the world. Without exception, they find that very high penetrations of RE are achievable, subject to the local availability of renewable energy resources. Detailed high penetration RE scenarios are now emerging from government and industry (German Advisory Council on the Environment 2011; Mai et al. 2012; AEMO 2013a). This thesis contributes to the growing body of increasingly sophisticated scenarios made possible by modern computer systems and the availability of the necessary data.

Numerous 100% RE scenarios have now been published in the literature and some tend to be ambitious in scope or optimistic in their assumptions. Scholars and environment groups alike have undertaken scenario studies to demonstrate the potential for countries, regions, and the world, to meet 100% of energy demand from RE by some future date, typically mid-century. One problem with scenarios set so far into the future and based on so many assumptions is that the findings become more difficult to evaluate. Consequently, some of these studies are too easily dismissed as unrealistic. There is a place for a study less ambitious in scope and more cautious in approach that explores these questions specifically for 100% renewable electricity in the NEM. The present scenarios are limited to electrical energy only using unmodified electricity demand in 2010. There are no assumptions about demand reductions through electrical energy efficiency, as the intention is to show that 2010 demand could have been met through renewable sources using the observed weather in that year. However, a sensitivity analysis of the impact on reliability of reducing peak demands has been performed.

The study also conservatively assumes that the only RE technologies that can be used in the scenarios are those that are commercially available today. These are on-shore wind power, flat plate photovoltaic (PV) power, parabolic trough concentrating solar thermal (CST) power with thermal storage, the existing hydroelectric stations in the NEM, and open cycle gas turbines fuelled with biofuels. It is argued that it is not necessary for less mature RE technologies, some still in the pilot stage, to become commercially available before reliable 100% renewable electricity can be achieved. Furthermore, it should not be necessary to include an RE technology with a high capacity factor like hot dry rock geothermal, so-called 'baseload' generation, to achieve system reliability.

The scenarios of 100% renewable electricity systems necessarily exclude all existing fossil-fuelled generation. Therefore, the intermediate stages between the present system and the 100% RE one are not examined. The thesis overlooks the difficulties of integrating increasing levels of RE into the existing inflexible fossil-fuelled system.

The NEM covers a very large geographic area and spans multiple climate zones. This is beneficial from the perspective of 100% renewable electricity. Australia has the key elements to make renewable electricity more feasible at an operational level than most other countries in the world. Australia has a low population, a large land mass (much of it sparsely populated), and manifold low carbon electricity options including a world renowned solar resource, wind, biomass, marine and geothermal energy (Geoscience Australia and ABARE 2010). Considerable aquifer storage also exists for carbon sequestration (Carbon Storage Taskforce 2009), although some storage sites are a long distance from existing coal-fired power stations.

1.4 Organisation of the thesis

The remainder of the thesis is organised as follows.

Chapter 2 gives the context for decarbonising the National Electricity Market as an Australian and a global response to climate change. This chapter describes the national circumstances of Australia, explains how the electricity industry became one of the most emissions intensive in the OECD, and then outlines current Australian Government policies to rectify this. These policies are contrasted with the long-term energy policies of Germany and Denmark, two countries leading the world in transforming its energy systems.

Chapter 3 reviews previous literature on energy system scenarios providing 80–100% of end-use energy from renewable sources. The literature makes it clear that a 100% renewable electricity scenario in the NEM should be operationally feasible, particularly for a country with a relatively small population and such large RE resources. The review evaluates various approaches to modelling such scenarios and places the contribution of this thesis into the existing literature.

Chapter 4 describes the approach taken in this thesis to simulate the operation of the NEM. The modelling tool and the data used by the model are described. The chapter emphasises the principles and decisions influencing the construction of the model (ie, more *why* than *what*).

Chapter 5 applies the modelling tool to test the ability for a selected mix of RE generation to meet the NEM reliability standard in the year 2010. The principal challenge identified is to generate sufficient power during the evening peak periods in the winter months. A number of possible approaches to dealing with these periods are tested.

Chapter 6 extends the work of Chapter 5 to examine the economics. Instead of selecting a mix of 100% RE generation to meet the NEM reliability standard, costs are assigned to each eligible renewable technology and a genetic algorithm (GA) is used to search for the lowest cost mix that can meet the reliability standard. Under a range of different economic assumptions, the GA produces mixes substantially different to those chosen by hand in the Chapter 5. The costs of these systems are compared with the cost of replacing all coal and gas generation in the NEM with efficient fossil-fuelled replacements with a carbon price being paid on their emissions.

Chapter 7 compares the least cost 100% renewable scenarios of Chapter 6 with a number of alternative scenarios based on efficient use of coal-fired and gas-fired generation with CCS, and open cycle gas turbines (OCGTs) for peak load. The economically optimal mixes of these fossil-fuelled scenarios are found using the same GA-based simulation tool.

Chapter 8 presents two analyses of solar direct normal irradiance (DNI) and wind characteristics. An appreciation for the temporal and spatial characteristics of wind and solar DNI is crucial for the successful integration of wind power and CST into electricity system at high penetration. The tempo-spatial characteristics of the wind can assist with siting wind farms to reduce the variability of wind farm output and lift the contribution of wind power in the 100% renewable electricity scenarios. Similarly, understanding the length of continuous periods of low DNI and their spatial distribution assists with siting CST plants to minimise the impact of long runs of low DNI with no power generated by such plants.

Chapter 9 draws together the key findings and implications from Chapters 5 to 8. A detailed examination and comparison of the Australian Energy Market Operator (AEMO) 100% Renewables Study is undertaken in this chapter given its close relationship with the work in this thesis. Further insights are given into a new view of operating the electricity supply-demand system and the sensitivity of the results to costs and technology availability. Finally, the limitations of the research are discussed.

Chapter 10 concludes the thesis. Given the positive findings, suitable policies to bring about the transformation to 100% renewable electricity are discussed. Recommendations are made for further work.

Chapter 2

Context

Climate change is an urgent problem. Large, rapid and sustained emissions reductions are now required to avoid dangerous global warming. Achieving deep cuts to greenhouse gas emissions in some sectors (eg, transportation, agriculture) is likely to be more difficult than in the electricity sector. Given the low carbon options now available for electricity generation, the electricity sector could be almost completely decarbonised to contribute towards the deep 2050 reduction targets agreed to by many industrialised countries. While full decarbonisation of such countries is indeed a formidable task, the electricity sector is a prime candidate for rapid decarbonisation due to its significant greenhouse gas emissions yet wide range of zero emission supply options. One possible approach to decarbonising the electricity sector being considered around the world is a transition to 100% or nearly 100% renewable energy (RE) sources.

This chapter places the motivation to decarbonise electricity supply into the context of an Australian and a global response to climate change. The national circumstances of Australia are outlined in Section 2.1 to give readers an appreciation of the present energy system and, in particular, the configuration of the electricity sector. The Australian National Electricity Market (NEM) is introduced in Section 2.2. Present and possible future policies to promote renewable electricity in Australia are presented in Section 2.3. These policies are briefly contrasted with the ambitious policies of Germany and Denmark in Section 2.4. Readers familiar with the Australian situation may skip directly to Section 2.4 or skip the entire chapter.

2.1 National circumstances of Australia

The national circumstances of Australia are somewhat unique for a developed country. It is an expansive country (almost 8 million square kilometres) with a small but sharply growing population of 23 million people. Australia is a highly urbanised nation with the population concentrated in five major cities with populations of more than one million people each. Around 40% of Australians live in Sydney and Melbourne, the two largest cities.

Australia also has an unusual greenhouse gas emissions profile for an industrialised country, largely dictated by the structure of the economy (Pezzey et al. 2010). Australia is a wealthy nation with a well educated workforce and a technological services sector, but with a large share of commodity exports from primary industries. Australia is a large exporter of agricultural products, minerals, coal, and liquefied natural gas.

Australia contributes around 1.5% of total world-wide greenhouse gas emissions (Garnaut 2011a, Chapter 12), if emissions from the combustion of the country's very significant fossil fuel exports are excluded. Australia is the highest per capita emitter of greenhouse gases among OECD member countries, with twice the OECD average and four times the world average, when the land use, land use change and forestry (LULUCF) sector is included (Garnaut 2011a). Garnaut (2011a) notes that this is predominately due to the emissions intensity of energy use. The following factors differentiate Australia from most other industrialised countries:

- heavy reliance on coal-fired electricity, discussed below;
- high population growth compared with other OECD countries due to immigration policies – 1.8% in 2012-13 (Australian Bureau of Statistics 2013);
- a substantial share (15%) of national greenhouse gas emissions from the production of agricultural commodities including meat, grain, wool and

cotton (Department of the Environment 2014);

- a net source of emissions in the LULUCF sector due to ongoing land use change (Department of the Environment 2014); and

- exports of energy intensive materials and products, with Australia being one of the largest exporters of thermal and coking coal in the world by volume (Bureau of Resources and Energy Economics 2013b).

Structural aspects of the economy and historical planning decisions are responsible for the high per capita emissions in Australia. While other OECD countries have been moving to lower emission electricity generation over previous decades for reasons largely unrelated to climate protection, Australia increased its dependence on coal (Garnaut 2011a). Coal is an abundant fuel available across Australia, can be extracted cheaply, and avoids the need to import fossil fuels.

The mix of electricity generation in Australia has been shaped substantially by the expansionary period after World War II. Individual states explicitly chose to avoid fuel dependence on other states. Coal mining strikes in 1949 in New South Wales led Victoria to pursue greater use of locally available brown coal (Saddler 1981). Significant substitution of oil with coal and natural gas occurred in the decade following the oil price shocks of the 1970s (Bureau of Resource Economics 1987). The Tasmanian Government pursued a long-term economic plan, the so-called hydro-industrialisation of Tasmania, by substantially expanding the use of hydroelectric power. This plan was ultimately hindered by environmental opposition to dam building. This opposition, and widespread public opposition to nuclear power, further entrenched coal use in Australia. Furthermore, as Molyneaux et al. (2013) notes, low cost coal-fired electricity was expanded in the 1980s to attract foreign investment in energy intensive manufacturing such as aluminium. These factors have contributed to an electricity industry in Australia that is highly emissions intensive by world standards, with an ageing fleet of fossil-fuelled generators (Figure 2.2) and dependence on domestic supplies of brown and black coal (Garnaut 2011a; Ison et al. 2011).

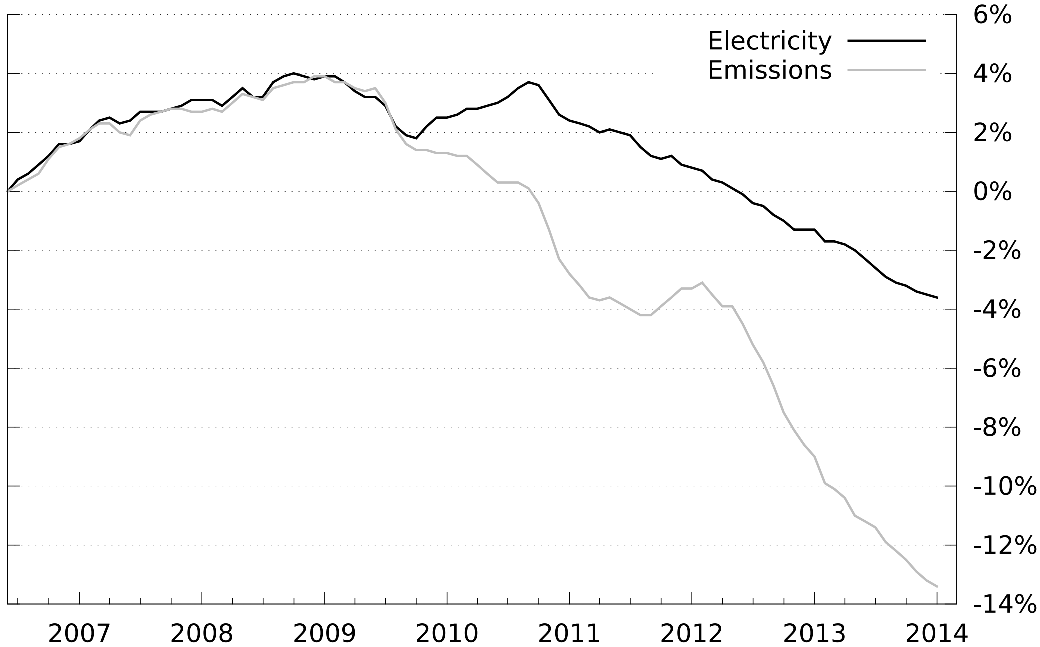

Figure 2.1: Percentage change in electricity generation and electricity emissions in the NEM. Data source: pitt&sherry CEDEX®, based on AEMO data, sourced via NEM-Review.

In 2008, greenhouse gas emissions from the electricity industry in Australia peaked at 205 megatonnes (Mt) of CO_2-e (Department of the Environment 2014). The electricity sector is the single largest source of emissions by sector and still represents over one third of national emissions. Since then, as a result of the policies to promote renewable electricity and unfavourable economic conditions for Australian manufacturing, emissions from the electricity sector have declined due to lower emissions intensity and lower demand (see Figure 2.1). Over the past decade, and even with relatively modest RE targets, there has been significant deployment of wind and solar generation.

If Australia, currently one of the world's highest per capita greenhouse emitters, is to make its fair contribution to such emission reductions then its highly emissions intensive electricity industry must rapidly transition to zero carbon sources (Garnaut 2011a). Given the long life of electricity industry assets, Australian energy and climate policy must therefore now consider the potential for future low emission electricity systems based on rapid deployment of commercially available zero carbon technologies. The only zero carbon 'sources' that are commercially

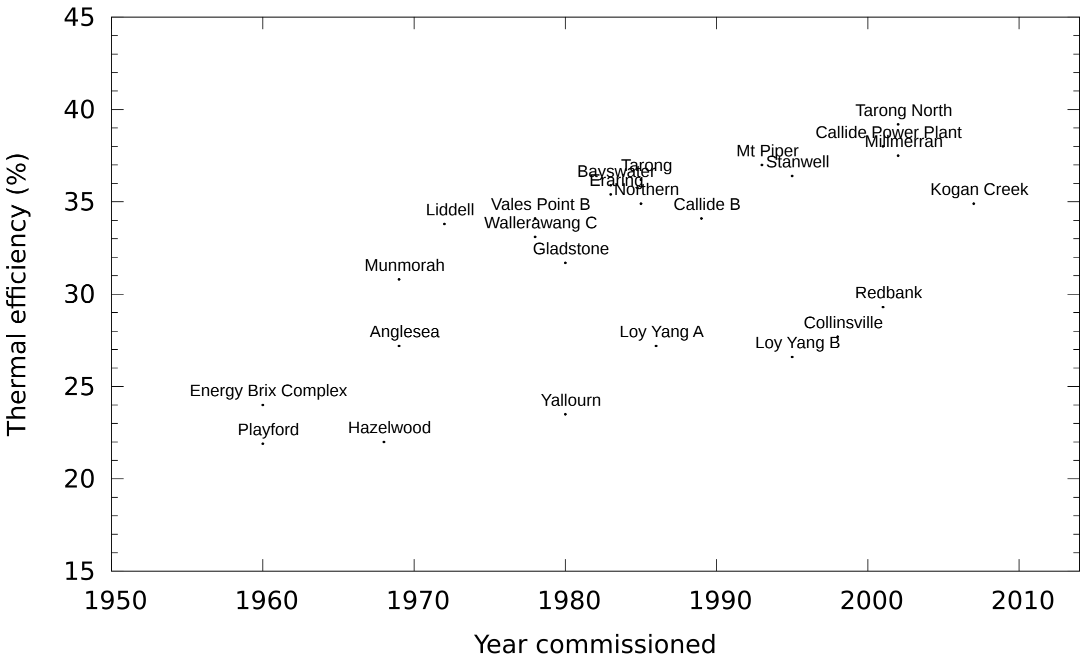

Figure 2.2: Approximate commissioning age versus thermal efficiency for current NEM coal-fired generators. Data source: AEMO (2012b)

available and seem likely to be able to make large contributions before 2020 in the Australian context are certain RE sources (Department of Resources, Energy and Tourism 2012) and demand reduction through efficient use of energy.

2.2 The Australian National Electricity Market

The electric supply systems in each state of Australia developed in isolation. Small, privately owned electricity generators emerged in the late 1800s in each city to supply electricity for two main uses: lighting and motive power. Generators were consequently situated close to load centres. With the development of high voltage transmission lines, state governments favoured centralised generation situated close to fuel sources and away from populated areas. Dams were established in Tasmania for hydroelectricity and coal mines opened on the mainland. The first major central power station on mainland Australia was the Yallourn station in the lignite-rich Latrobe Valley, linked to Melbourne via a 160 km transmission line (Brady 1996). Government policies fostering rural electrification further expanded the electricity network into country areas (Brady 1996). This also made existing distributed generation, mainly diesel generator sets, obsolete in these areas.

Each state and territory government operated a vertically integrated electricity industry. With the introduction of the NEM in the 1990s, each participating state and territory began restructuring their vertically integrated industries into four types of market participant: generator, transmission network service provider (TNSP), distribution network service provider (DNSP) and retailer. Initially, these were originally publicly owned corporations, but over time some states (eg, Victoria) privatised these corporations. Other states, such as New South Wales (NSW), retained some level of public ownership (Outhred 2004). The National Electricity Market Management Company (NEMMCO) was established in 1998 to function as both the power system operator and the financial market operator. In 2009, the AEMO superseded NEMMCO and now operates a wholesale market for natural gas as well.

The NEM is the amalgamation of restructured electricity industries in the states of Queensland, Victoria, NSW, Tasmania, South Australia (SA) and the Australian Capital Territory (ACT). The NEM has five market regions, one region for each of the states listed. The ACT does not have its own market region and is subsumed into the NSW region. The NEM supplies around 80% of electricity generated in Australia (Department of the Environment 2014).

The NEM is the largest interconnected power system in the world, spanning 5,000 km from Far North Queensland to South Australia (AEMO 2012a). Figure 2.3 illustrates how the network spans an area of almost four million square kilometres across diverse climate zones from the tropical far north to the cool temperate climate of Tasmania in the south. Climatic conditions in each zone can result in significant variation in weather systems, influencing the temporal and spatial patterns of electricity demand and renewable electricity supply on a range of time scales.

With the aim of enabling electricity trading and improving system reliability, the state grids have been slowly interconnected since the 1950s, although these

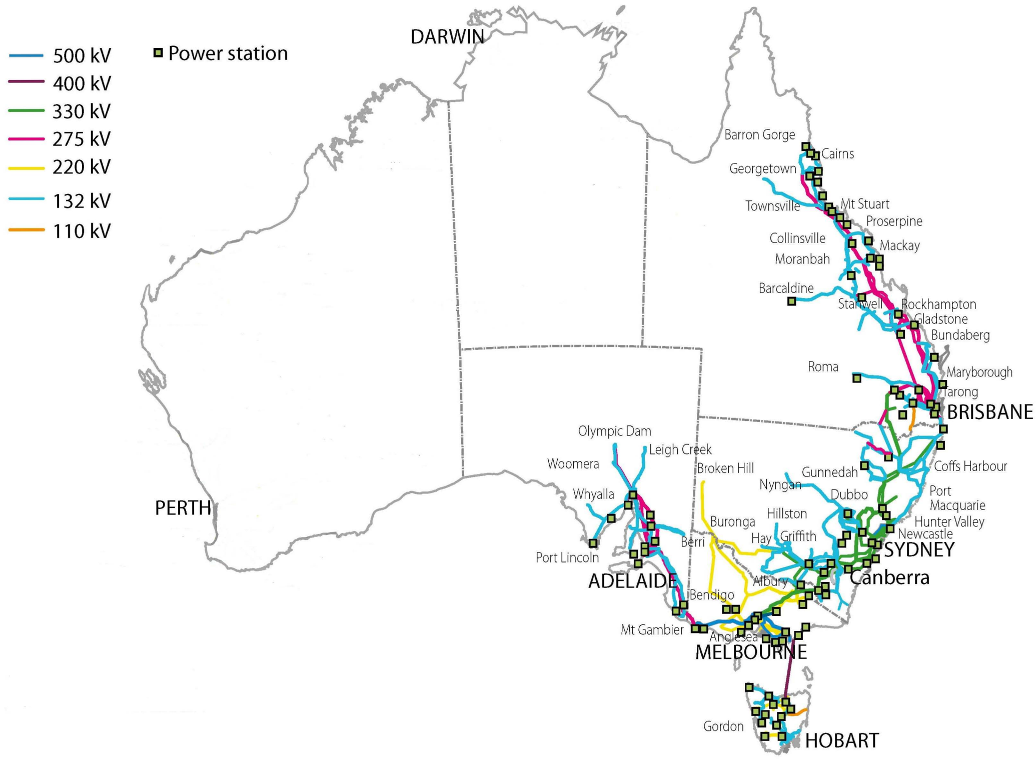

Figure 2.3: Existing power stations and transmission lines in the National Electricity Market. Locations are indicative only. Source: Geoscience Australia.

interconnections remain relatively weak (Diesendorf 2010). The main regional interconnections and transfer capabilities are:

- NSW and Victoria were first interconnected through the construction of the Snowy Mountains Hydroelectric Scheme in 1959 (Brady 1996) with a thermal transfer limit of 3,100 MW to NSW and 1,900 MW to Victoria;
- South Australia and Victoria were connected in 1990 through the Heywood interconnector (460 MW) and the high voltage direct current (HVDC) Murraylink (220 MW) (Australian Energy Regulator 2011);
- NSW and Queensland were connected through two interconnectors in 2000: Directlink (180 MW) and the Queensland to New South Wales interconnector (QNI) with a transfer capability of 700 MW north and 1,078 MW south;
- Tasmania was connected in 2006 to the mainland via the Basslink HVDC link with a capacity of 480 MW (to Tasmania) and 600 MW (to Victoria).

The current regulations governing the construction of transmission assets and access to them are a substantial barrier to the expansion of RE into regions of Australia where renewable resources may be abundant (eg, direct beam solar radiation for solar thermal plants). The legislated rules of the NEM, the National Electricity Rules (NER), employ a *shallow connection* cost model governing how costs are assigned when a generator requests connection to the transmission network. In this model, generators pay for connection to the most suitable transmission connection point. Hence, it is important to minimise these costs, which are not necessarily faced by an incumbent generator. Before electricity industry restructuring, state governments in Australia constructed transmission lines to reach these generators.

The NER specifies a regulatory test that describes the circumstances under which a transmission network must be reinforced by the TNSPs. If the regulatory test does not support reinforcement, a generator may still self-fund an increase in transmission capacity. However, an open access policy permits other generators to connect to the network and benefit from any reinforcement. The open access policy introduces a further barrier to generators funding their own network reinforcement.

Generators, TNSPs, DNSPs and retailers are market participants in the NEM and operate under varying degrees of government regulation. With TNSPs and generators functioning as separate entities, the pathway for efficient investment in transmission is not straightforward (Chattopadhyay 2011). TNSPs may be reluctant to extend the network at the scale required for long-term development of generation in a region. Constructing a transmission network extension at an appropriate scale may be more economically efficient in the long run, but introduces a risk to the TNSP that the forecast generation does not materialise. Similarly, generation projects are unlikely to proceed without guaranteed available transmission. The problem is exacerbated by the large disparity in the time taken to construct smaller scale RE plants (2–3 years) and new transmission infrastructure at up to 10 years (Mills et al. 2009).

A proposed change to the NER in 2011 attempted to overcome the scenario described above by improving the public availability of information to market participants (Australian Energy Market Commission 2011). By allowing participants to better coordinate network extensions, the risk of network duplication or stranded assets can be minimised. This minimal approach to regulation provides no guarantee that the transmission network will be extended to connect a distant generator.

Experience in other more densely populated countries suggests that the expansion of transmission networks can be controversial, often requiring right-of-way through areas of conservation or heritage value, or raising community opposition to visual impact. Yeleti and Fu (2010) report that transmission line construction can be slow due to rights to land and planning approval. Georgilakis (2008) identifies inadequate transmission planning and unclear planning objectives as a significant barrier to the wider deployment of wind energy in the United States.

2.3 Policies to promote renewable energy in Australia

In the past decade, Australian state and federal governments have enacted numerous pieces of legislation to mitigate greenhouse gas emissions, with varying degrees of success. The scale and urgency of the climate change problem is not shared among the major political parties in Australia and the only policy that has weak bipartisan support is a 5% reduction in year 2000 greenhouse gas emissions by 2020. The lack of bipartisan support causes continual change of policy direction. Support policies for solar photovoltaic (PV), in particular, have changed so frequently and drastically that the solar PV industry has coined the term 'solar coaster'. In this section, the currently legislated policies in Australia to promote RE are presented, although their future is very uncertain. These are then briefly compared with the long-term energy policies of Germany and Denmark.

2.3.1 Carbon pricing

The Australian Government legislated the Clean Energy Future package in 2011 to put a price on greenhouse gas emissions using an emissions trading scheme. For the first three years of operation, permits would be assigned a fixed price and there would be no emissions trading. In 2015, the fixed price period was to end and emissions trading was to commence. The Government announced in 2013 that the fixed price period was to end a year earlier with emissions trading to commence in July 2014.

The policy includes a target of reducing emissions to 5% below 2000 levels by 2020 and, conditional upon certain specified international cooperation, potentially deeper cuts of up to 25% below year 2000 levels by 2020. A long-term target of 80% below year 2000 levels has been set for 2050. Only the low 5% target has bipartisan support. The Government elected in 2013 plans to abolish the carbon pricing scheme enacted by the previous government and replace it with a suite of 'direct action' measures including an emissions abatement fund (Naughten 2013). An indication of the effect of the carbon price in reducing the emissions intensity of electricity can already be seen in Figure 2.1, although there are other

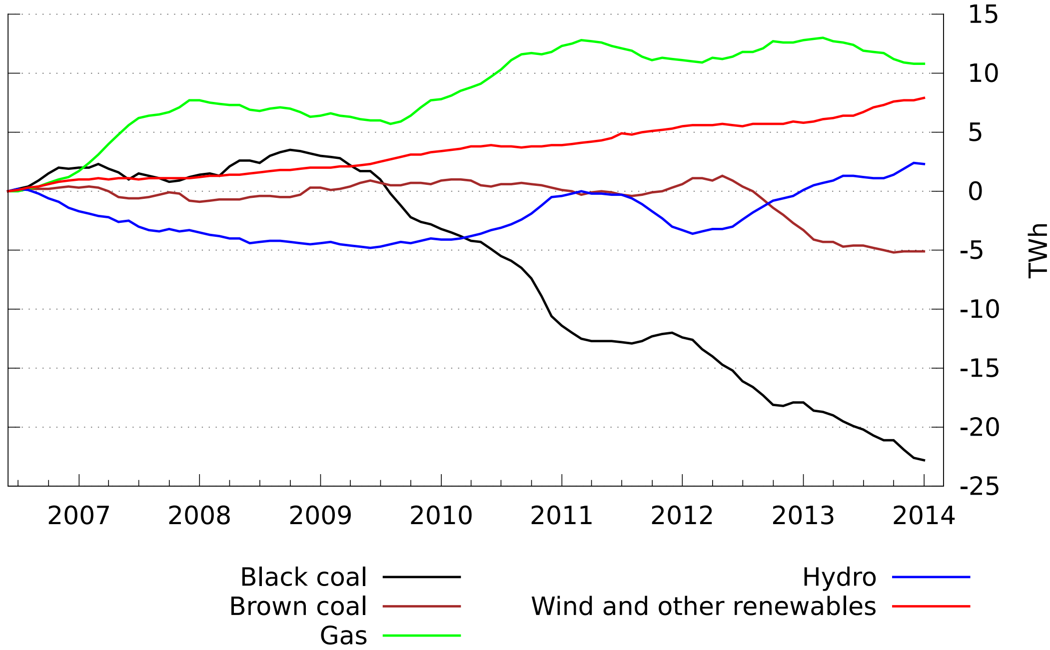

Figure 2.4: Change in electricity generation (TWh) by fuel source in the NEM. Data source: pitt&sherry CEDEX®, based on AEMO data, sourced via NEM-Review.

contributing factors including a rising share of renewable electricity.

2.3.2 Renewable energy targets

Australia's first legislated RE target, the Mandatory Renewable Energy Target (MRET), was introduced in 2001. The MRET specified that 9,500 GWh, or approximately 2% of national annual electricity demand would be generated from renewable sources by 2010 (Kent and Mercer 2006). In 2010, an expanded Renewable Energy Target (eRET) was legislated to source 45,000 GWh from renewables by 2020 – an estimated 20% of the electricity demand in 2020. As Figure 2.1 shows, electricity demand has been in decline in recent years. By 2020, eRET may deliver in excess of 25% of 2020 demand. When the legislation was introduced, environmental groups opposed the fixed 45,000 GWh target, fearing that electricity demand would grow faster than expected and that 45,000 GWh would represent less than 20% of demand in 2020. Industry bodies lobbied for a fixed target, arguing that it offered certainty. Against expectations, the decline in electricity demand since 2011 means that 45,000 GWh is likely to represent as much as 25%, contingent on further reductions in demand between 2014 and 2020.

The effect of the eRET and the fixed carbon price can be seen in the reduced intensity of emissions from electricity in Figure 2.1 and the change in fuel mix in Figure 2.4. These policies are producing encouraging results in South Australia. In 2012, South Australia produced 30% of its annual electricity from RE with the majority of this being generation coming from wind power (Pitt and Sherry 2013a). The experience with South Australia gives a brief glimpse into the way that the transition to 100% renewable electricity might occur.

2.3.3 Feed-in tariffs

From 2008, state governments introduced feed-in tariff schemes to promote small-scale solar PV and, in a few cases, small wind turbines. First to introduce a feed-in tariff was the Parliament of South Australia (2008). At the national level the Federal Government has instead favoured renewable portfolio standards (the eRET) over feed-in tariffs for large-scale generation.

The various feed-in tariff schemes around Australia differed in their design. Some schemes employed gross metering and some employed net metering, where only electricity exported to the grid was eligible for premium payments. Most schemes set long periods of guaranteed payments, but some had very short periods such as the NSW Solar Bonus Scheme. The Solar Bonus Scheme was to run for seven years and consequently used a high tariff level to give a sufficiently high return on investment. Moreover, the scheme did not guarantee payments for all seven years. The program was open for seven years in total, so entrants in the fourth year were guaranteed payments for only three years. This created a stampede in the first several years and the total costs of the program grew very quickly. The scheme was not only cancelled, but the NSW Government unsuccessfully attempted to retrospectively cancel payments for existing PV system owners.

As the cost of PV systems fell and incentives became too attractive, support programs were terminated abruptly and replaced with much less attractive incentives. For example, in 2014, a PV system owner in NSW is paid around 8 c/kWh for electricity exported to the grid. Self-consumed electricity, which tends to be limited for many households, is credited at the retail tariff.

State governments were not effective in managing tariff levels as the costs of PV fell dramatically between 2010 and 2014. While arguably poorly managed, these programs were successful in fostering a small-scale PV industry in Australia. Over one million households in Australia have a rooftop PV system in 2014 totalling over 3 GW of capacity. In South Australia, around one in four households has rooftop solar PV.

2.4 A contrast with Danish and German energy policies

The political environment for climate policy in Australia in 2014 is best described as fractious. The main policies used in Australia to address climate change, carbon pricing and the use of RE, are structurally sound, but lack bipartisan support and are not ambitious enough to match the recommendations of the Intergovernmental Panel on Climate Change (IPCC). There are also strong political barriers to the wider adoption of renewable energy in Australia (Effendi and Courvisanos 2012). In contrast, two nations that are leading the world in RE policy are Denmark and Germany. The motivation of both countries extends beyond climate protection. The promotion of RE is based around a desire to eliminate the use of imported fuels and to gain leadership in the design and development of clean technologies.

2.4.1 Denmark

In February 2011, the Danish Government released a long-term energy plan titled *Energy Strategy 2050* (Danish Government 2011). Denmark has expressed a desire to be free of the economic risks associated with rising and volatile prices for imported fossil fuels. The plan therefore emphasises the goal of becoming independent of fossil fuel by 2050 for reasons of energy security, foreign policy, climate protection and growth in Danish clean energy industries. In 2009, 12% of Denmark's exports were in this sector (Danish Government 2011). The Danish Government is conscious of the impacts of such a transition on public budgets and the competitiveness of Danish companies. The short-term initiatives in the plan are said to be fully financed.

Denmark has been making this transition for some time. The shift in the fuel mix in Denmark began after the 1970s oil shocks. Since 1980, energy consumption in Denmark has been virtually constant (Mathiesen et al. 2012) while the Danish economy has continued to grow and, consequently, Denmark is a leader in energy efficiency. Energy Strategy 2050 places a strong emphasis on the on-going role of energy efficiency.

A stated goal of the Danish strategy is a greenhouse neutral energy system using either 100% RE or a mixture of RE and, if necessary, coal-fired electricity equipped with carbon capture and storage (CCS). However, it is clear that the Danish strategy is not contingent on CCS technology becoming available. The plan sets out a 60% renewable electricity target for 2020, with two-thirds of this coming from wind power. The remaining 20% will be mostly sourced from bioenergy. The plan entails the following core elements:

- energy efficiency in buildings, particularly retrofits to existing building stock;
- electrification of heating, industrial processes and, where possible, transportation (eg, electric passenger vehicles);
- further expansion of wind power and other renewable technologies;
- increased use of bioenergy in the form of biomass and biogas in existing gas grids;
- increased use of efficient district heating; and
- smarter use of energy through demand shifting, storage, electric boilers[1], and expanded regional trading of electricity;

[1]It is notable that Denmark anticipates a role for electric boilers in integrating larger amounts of

The Danish strategy acknowledges that the technologies required for the transition are in various stages of maturity. The plan therefore classifies initiatives as belonging to one of three different tracks: a short-term transition track, where energy efficiency and commercially available renewable technologies are deployed; a track for medium-term planning; and a research and development track for developing the technologies that will ultimate be required in the long-term.

2.4.2 Germany

In Germany, the *Energiewende* or 'energy transition' was an idea that emerged in the early 1980s to transition Germany away from nuclear power and oil. A number of policies were introduced in the intervening years to bring this transition about, although progress was slow. In 1991, the world's first feed-in tariff legislation was implemented through the Electricity Feed-in Act. In 2000, the legislation was overhauled and renamed the Erneuerbare-Energien-Gesetz (EEG) or Renewable Energies Act.

In 2010, the German Federal Government (hereafter, the German Government) released the Energy Concept 2010 plan (German Federal Ministry of Technology and Economics 2010). This long-term plan outlines how Germany will meet its 2050 emissions reduction target and how it can transition to predominantly RE by the middle of the century. The German Government called on energy system experts to produce energy scenarios for the Energy Concept. These showed that 'the path to the age of renewable energy is possible and passable', subject to numerous caveats (German Federal Ministry of Technology and Economics 2010). The required investment is estimated to be around €20 billion (A$ 31 billion) per year.

The objectives of the plan include energy security, economic competitiveness for Germany, and climate protection (German Federal Ministry of Technology and Economics 2010). There are four pillars to the plan: the use of RE, energy effi-

variable renewable generation, while various Australian state governments have banned the use of electric water heaters in new homes because they are usually powered by emissions intensive electricity.

ciency mainly in the building sector, reinforced electricity grids (including smart grid technology and time of use pricing), and energy storage (eg, by promoting electric vehicles, pumped storage hydroelectricity, and biomass plants as sources of dispatchable power).

The plan is not highly detailed and avoids being prescriptive in view of technological advancements and economics that cannot be anticipated so far into the future. As an example of the difficulty in making such long-term predictions, the Energy Concept, released in September 2010, recommended extending the service life of the 17 existing German nuclear power stations as interim low-carbon generation. Power stations commissioned prior to 1980 were to be operated for a further eight years. Those after 1980 would be operated for 14 more years. The Fukushima Daiichi nuclear disaster occurred in March 2011 and in June 2011 an abrupt shift in German Government policy on nuclear power led to a revision of the Energy Concept plan. Eight of the operational reactors were shut down soon after the Fukushima disaster and the remainder will be shut down by 2022.

The Energy Concept reinforces the point that, although Germany is committed to the Energiewende, the government is highly aware of the costs and is actively developing policies to enact the transition at lowest possible cost. For example, after 14 years of operation, the fixed feed-in tariff payments to renewable electricity generators are being modified to incorporate a greater degree of market orientation. Generators can now elect to accept a premium payment above electricity market prices. Additional policies will be enacted to ensure that bioenergy use does not compete with food or feed production, that subsidies to hard coal production are cancelled, and to 'promote the construction of highly efficient fossil fuel power plants that are CCS-ready.' The German Government recognises that electricity markets may need to be redesigned due to the large amount of electricity generation with low marginal costs and the requirement for firm capacity to be appropriately compensated, such as by using a capacity market.

The Energy Concept includes long-term planning for the rapid reinforcement of the grid, something that is not often discussed in Australia. In addition to the identified need for a north-south transmission spine to transmit wind power from the north to load centres in the south, the plan includes improving interconnection with neighbouring countries. The plan incorporates the use of a public awareness campaign on the role of electricity networks in achieving a highly renewable electricity supply, given that building transmission lines can be contentious in Europe.

2.5 Chapter summary

The long-term plans of Denmark and Germany show that both countries envisage a future energy system that is largely free of fossil and nuclear energy. The plans are necessarily indefinite due to the uncertainties involved in planning an energy system 35 years hence. Nevertheless, these documents demonstrate the political will in some countries to transition to RE sources for a range of reasons. The Australian Government has also been engaging in long-term planning for the future energy system (Department of Resources, Energy and Tourism 2012). In these analyses, there is a persistent assumption that fossil fuels, mainly natural gas and coal with CCS, will continue to play a significant role in the Australian energy system well into the future.

In contrast to Germany and Denmark, Australia has weak near-term greenhouse gas reduction targets and RE targets. By comparison with the energy policies of Germany and Denmark, the policies of Australia appear simplistic, disjointed, and lacking in commitment. Progress is being hindered by a lack of public insistence for climate change action, which will impose some costs, and only partisan support for the necessary policies. Some of the recent changes to policy direction at state and national levels, outlined above in Section 2.3, could be interpreted as attempts to slow the deployment of RE. It is in the context of national energy planning like the Energiewende in Germany and Energy Strategy 2050 in Denmark that 100% renewable electricity scenarios become a relevant and timely field of research.

Chapter 3

The literature

3.1 Introduction

Studies of scenarios with high levels of renewable energy (RE) demonstrate the ability for cities, states and countries to transform their energy systems to RE. Scenarios can be used to inspire the population, inform public policy, or to simply counter claims that it is impossible to drastically reduce the use of fossil fuels. The use of the scenario approach to the radical transformation of energy systems was pioneered by Sørensen (1975) for Denmark in the year 2050. In the 1970s, the rationale for aggressive use of RE by countries such as Denmark was to achieve independence from imported oil. Today the emphasis has shifted somewhat to improving national energy security more generally and reducing greenhouse gas emissions. Some of Sørensen's predictions of developments in the 21st century are remarkably accurate. In 1975, Sørensen anticipated a future where telecommuting, videoconferencing and online shopping 'based on selecting merchandise from computerized video displays' could be used to reduce demand for transportation energy. Furthermore, Sørensen suggested that wind power should be the preferred method of producing electricity, and potentially heat, a prediction that still may come to pass in Denmark. Building on earlier work demonstrating, at a broad level, the technical feasibility of high penetration renewable electricity, models are becoming more sophisticated.

Scenarios are typically set in a future year, commonly the year 2050. This choice is influenced by the goal of significantly reducing or eliminating the use of fossil fuels by mid-century. Due to the complexity of the task, many assumptions must be made. Cochran et al. (2014b) performed a meta-analysis of 12 high penetration renewable electricity studies noting that scenarios with narrower scope are more readily compared. However, different methodologies and assumptions still make direct comparisons difficult. Accurate long-term predictions of energy demand, rates of technological progress, political will for change, and climate change policies are challenging and are discussed further in Section 3.9. Within these limitations, however, the scenarios described in this chapter are valuable in understanding what is technically feasible and what difficulties arise in the evolution of a future RE system.

Scenarios of high penetration RE remain somewhat controversial (Cochran et al. 2014b; Smil 2012; Delucchi and Jacobson 2012; Trainer 2012, 2010). Solomon and Krishna (2011) document the limited number of successful wholesale, rapid energy transitions that society has achieved: Brazil to ethanol and France to nuclear power, and argues that a transition world-wide to RE could be very slow. Beyond the potential costs and speed of a transition away from fossil fuel dominated energy systems, a range of technical concerns have been raised, particularly in the context of the electricity industry. Balancing supply and demand across the full range of time scales is a high priority for the electricity industry, given that most energy use is variable and somewhat unpredictable, and power stations sometimes experience unforeseen outages. The variability of weather-driven electricity generation raises additional challenges (MacGill 2010; Outhred and Thorncraft 2010).

It has been argued that it is not technically feasible to reliably operate an electricity industry with 100% renewable generation without major technical breakthroughs in these technologies, or complementary storage technologies (Sharman et al. 2011). Glasnovic and Margeta (2011) suggest that variable renewable generation is incapable of 'continuous electric supply' and that this problem can be overcome by coupling all variable generation to pumped storage hydro (PSH) plants with two parallel pipelines. This would enable variable flow into the upper reservoir and constant flow down to the lower reservoir. Glasnovic and Margeta (2011, p. 1876) dismiss the losses that would be experienced in such a system as 'the price paid for the new quality in green energy production'. No other scholars in the literature surveyed view the integration of RE in this way.

There are a diverse set of views in this relatively new field of research. Some scenarios are highly optimistic about what can be achieved through deep demand reductions, energy efficiency, or technological developments in energy supply. The critics view renewable energy supply on a large scale as unachievable or unaffordable. The views of both the critics and the optimistic thinkers have influenced the conservative assumptions and approach used in this thesis as a means of striking a middle ground.

3.2 Classifying scenarios

Table 3.1 summarises the main characteristics from a survey of 100% (or near 100%) RE and renewable electricity scenarios in the literature. Several literature reviews have been published contrasting the numerous scenarios in the literature (Cochran et al. 2014b; Reedman 2012). The table has been partially derived from a table by Reedman (2012) with additional data from the author and from Diesendorf (2014). The 'Year published' column of the table shows that this field has been very active since 2009. Scenarios are published in peer-reviewed journals, in books, and in the grey literature. Due to limitations of length, detailed scenarios in journals are summarised or published as a series of papers. The detailed and lengthy reports produced by industry and advocacy groups such as WWF (2011) and the Centre for Alternative Technology (Allen et al. 2013) are informally reviewed by others.

Columns of the table that are not self-explanatory are explained below:

How published – whether published in a journal, stand-alone report or book;

Sector – sector covered (electricity, electricity and heat, final energy or all sectors of the economy);

Approach – the technique or software package used for modelling the scenario (details in Section 3.4);

Demand change – whether the scenario increases future demand (to account for increased electrification) or decreases it (to incorporate improvements in energy efficiency);

Storage – whether the scenario includes storage technologies such as pumped storage hydro (PSH), compressed air energy storage (CAES) or batteries;

Transition path – whether the scenario is for a single future year or presented as a number of steps on the transition from the present to the future year;

Transmission – in the case of electricity sector scenarios, whether transmission network requirements or upgrades are considered;

Costs – whether the study includes an estimation of the costs; and

Reference (ref.) scenario – whether the study includes a reference scenario of any kind.

Author(s)	Year published	How published	Target (% RE)	Sector	Geographic scope	Location	Spatial res.	Temporal res.	Approach	Demand change	Storage	Transition path	Transmission	Costs	Ref. scenario
Global scenarios															
Riahi et al.	2012	B	90	Final energy	G	Global	Regional	Annual	MESSAGE & IMAGE	×		×		×	×
Teske et al.	2012	R	92	Final energy	G	Global	Regional	Annual	Simulation	×	×	×		×	×
Jacobson and Delucchi Delucchi and Jacobson	2011	J	100	Final energy	G	Global	1.5°	Annual	Stat. analysis	×	×		×	×	
Føyn et al.	2011	J	100	Final energy	G	Global	Multi-country	Load block	TIAM	×	×	×	×	×	×
Glasnovic and Margeta	2011	J	100	Electricity	G	Global	Multi-scale	Annual	Simulation	×	×	×			
WWF	2011	R	100	Final energy	G	Global	Multi-country	Annual	Stat. analysis	×		×			
Sørensen and Meibom	2000	J	100	Final energy	N	Global	Regional	Seasonal	GIS	×	×				
Regional scenarios															
Rodríguez et al. Rasmussen et al. Heide et al. Heide et al.	2014 2012 2011 2010	J	100	Electricity	R	Europe	50 km	Hourly	Optimisation	×	×	×	×		
Euro. Climate Found.	2011	R	100	All economy	R	Europe	Regional	Hourly	Optimisation	×	×	×	×	×	×

Note: How published: (J)ournal, (R)eport, (B)ook, Scope: (G)lobal, (R)egional, (N)ational, (S)ub-national (continued on next page)

Author(s)	Year published	How published	Target (% RE)	Sector	Geographic scope	Location	Spatial res.	Temporal res.	Approach	Demand change	Storage	Transition path	Transmission	Costs	Ref. scenario
Regional scenarios (continued)															
Schellekens et al.	2011	R	100	Electricity	R	Europe and North Africa	Multi-country	Annual	Roadmap	×			×		
Zervos et al.	2010	R	100	Final energy	R	Europe	Multi-country	Annual	Simulation	×	×	×			
Sørensen	2008	J	100	Final energy	R	N. Europe	National	6-hourly	Simulation	×	×		×		
National and sub-national scenarios															
Henning and Palzer Palzer and Henning	2014	J	100	Electricity & heat	N	Germany	National	Hourly	REMod-D		×			×	
AEMO	2013	R	100	Electricity	S	NEM	Regional	Hourly	Optimisation	×			×	×	
Elliston et al.	2013	J	100	Electricity	S	NEM	Regional	Hourly	Optimisation		×		×	×	×
Allen et al.	2013	R	99	All economy	N	UK	National	Annual	Optimisation	×	×	×			
Devogelaer et al.	2013	R	100	Final energy[1]	N	Belgium	National	78 periods per year	TIMES	×	×	×	×	×	×
Budischak et al.	2013	J	99	Electricity	S	PJM (USA)	Regional	Hourly	Optimisation		×			×	
Jacobson et al.	2013	J	100	Final energy	S	New York	State	Annual	Simulation	×	×			×	
Mason et al.	2013	J	100	Electricity	N	New Zealand	Multi-scale	Half-hourly	Optimisation		×				
Sustainable Energy Now	2013	R	100	Electricity	S	W. Australia	State	Annual	Simulation	×	×		×	×	×

Note: How published: (J)ournal, (R)eport, (B)ook, Scope: (G)lobal, (R)egional, (N)ational, (S)ub-national (continued on next page)

[1]Excludes aviation.

Author(s)	Year published	How published	Target (% RE)	Sector	Geographic scope	Location	Spatial res.	Temporal res.	Approach	Demand change	Storage	Transition path	Transmission	Costs	Ref. scenario
National and sub-national scenarios (continued)															
WWF and TERI	2013	R	100	All economy	N	India	National	Annual	MARKAL	×	×	×			×
Ćosić et al.	2012	J	100	Final energy	N	Macedonia	National	Hourly	EnergyPLAN	×	×	×		×	×
Esteban et al.	2012	J	100	Electricity	N	Japan	Regional	Hourly	Simulation	×	×				
Huva et al.	2012	J	100	Electricity	S	Victoria	1.5 km	Half-hourly	Optimisation					×	
Mai et al.	2012	R	90	Electricity	N	USA	Multi-scale	Load block/hourly	ReEDS/GridView	×	×	×	×	×	×
Tsuchiya	2012	J	100	Electricity	N	Japan	Regional	Hourly	Simulation	×	×				
Connolly et al.	2011	J	100	Final energy	N	Ireland	National	Hourly	EnergyPLAN		×				
German Adv. Council	2011	R	100	Electricity	N	Germany	10 km	Hourly	REMix	×	×			×	×
Krajačić et al.	2011	J	100	Electricity	N	Portugal	Multi-scale	Hourly	H_2RES		×				×
Sinclair Knight Merz	2010	R	100	Final energy	S	Victoria	Regional	Annual	Stat. analysis	×	×				
Wright and Hearps	2010	R	100	Electricity	N	Australia	National	Half-hourly	Simulation	×	×	×	×	×	
Fthenakis et al.	2009	J	100	Final energy	N	USA	National	Hourly	Simulation	×	×	×	×		
Lund and Mathiesen	2009	J	100	Final energy	N	Denmark	National	Hourly	EnergyPLAN			×			×
Lehmann	2003	R	100	Final energy	N	Japan	Regional	Load block	SimREN	×	×				
Note: How published: (J)ournal, (R)eport, (B)ook, Scope: (G)lobal, (R)egional, (N)ational, (S)ub-national															

Table 3.1: Scenarios of 100% (or near 100%) renewable energy; partially derived from Reedman (2012) and Diesendorf (2014)

Hart et al. (2012) suggest an alternative classification for scenarios: zeroth order, first order and second order analyses. Zeroth order analyses use annual or seasonal averages of resource availability. First order analyses use deterministic time series data to characterise resource variability. Second order analyses use stochastic programming techniques such as Monte Carlo simulation to characterise resource and demand uncertainty by means of probability distributions. Early work in this field typically involved zeroth order analyses. In contemporary efforts, first order analysis is the most common. Hart and Jacobson (2011) is the only study reviewed that can be classified as a second order analysis. This study uses Monte Carlo simulation to vary wind, solar, demand, and forced outage events while maintaining meaningful spatial and temporal correlations in the data.

3.3 Technology choices

Each scenario assumes a different set of RE technologies. This choice is influenced by the sectors covered in the scenario, RE resources available in the locality, and how conservative the scenario assumptions are. More conservative scenarios may assume no or little progress in the development of RE technologies in the future. This has the advantage of not predicating the results on the existence of any one 'silver bullet' technology. The set of eligible energy supply and demand technologies is restricted to those that are commercially available today, for example, on-shore and off-shore wind power, solar photovoltaic (PV) power, concentrating solar thermal (CST), hydroelectricity, PSH, combined heat and power (CHP), heat pumps, electric vehicles, biomass, and demand management. Some studies use a restricted set of technologies to explore optimal mixes such as wind and PV (Heide et al. 2010) or wind and CST (Huva et al. 2012). This does not suggest that other technologies are not suitable or beneficial.

Every scenario in Table 3.1 includes on-shore wind power and, where applicable, existing hydroelectric facilities. There is a consensus that, with the exception of countries like China (Liu et al. 2011), conventional hydroelectricity potential has been largely exploited in industrialised countries. The widespread use of wind power in the scenarios reflects the maturity of this technology. Cochran et al. (2014b) found that on-shore wind is frequently the largest contributor in the scenarios they surveyed. The authors include an insightful plot comparing the share of electricity from each scenario they examined. It has not been reproduced here, but the reader is referred to Cochran et al. (2014b).

Off-shore wind is utilised in most of the global scenarios. It also features in national scenarios where there is either a good off-shore wind resource or prior experience with this recently commercial technology (Allen et al. 2013; Mai et al. 2012). None of the scenarios for Australia consider off-shore wind power, perhaps because there is so much on-shore wind potential still to be utilised. Huva et al. (2012) use a numerical weather model (NWM) to produce wind speed data over land, which could readily be expanded to produce off-shore wind data.

Solar PV is a popular technology in all scenarios, with the exception of García-Olivares et al. (2012), which includes CST but not PV in their global scenario. The authors exclude PV due to concerns about the scarcity of materials required to manufacture PV modules, a claim invalidated by evidence from Jacobson and Delucchi (2011). Scenarios utilising rooftop solar PV also tend to include utility-scale PV, however studies that favour distributed generation technologies may exclude utility-scale PV (Allen et al. 2013). In some locations (eg, those with a high population density) the share of energy from rooftop PV may be limited. The high dependence on CST sited in regions of high direct beam solar radiation in the García-Olivares et al. (2012) scenario makes the transmission requirements much larger. This is discussed further in Section 3.7.

A plausible assumption of some scenarios is that RE technologies in the demonstration stage today will be available before the scenario target year is reached. Jacobson and Delucchi (2011) include technologies that are at the demonstration stage. Wave and tidal power are utilised in many scenarios (Jacobson and Delucchi 2011; Føyn et al. 2011; Allen et al. 2013; Sinclair Knight Merz 2010; Lund and Mathiesen 2009). Enhanced (or engineered) geothermal systems are included in a small number of scenarios (Føyn et al. 2011; AEMO 2013a; WWF 2011). Technologies still in the research and development (R&D) phase of maturity, such as solar updraft towers and ocean thermal energy conversion are not included in any scenario.

There are some notable technology choices in some of the scenarios. Wright and Hearps (2010) chose a large capacity of central receiver CST systems to meet 60% of Australian electricity demand due to the superior technical performance of central receiver systems over parabolic troughs, although this technology is arguably still at the demonstration stage. Jacobson and Delucchi (2011) limited the RE technologies to those using wind, water and sunlight (WWS): PV, CST, wind, wave, and tidal power, hydro and geothermal. Bioenergy is excluded due to concerns about competition for land use, water use, and air pollution. Fthenakis et al. (2009) also express concerns about the widespread substitution of bioenergy for fossil fuels. In *Zero Carbon Britain* (Allen et al. 2013), electricity is generated entirely from renewable sources with surplus electricity diverted to the production of synthetic fuels. Relatively small shares of solid, liquid and gaseous renewable fuels are used for demands that are difficult to satisfy with electricity (eg, industrial processes) or for balancing electricity supply and demand. Allen et al. (2013) chose biomass to generate heat and synthetic fuels using land formerly devoted to livestock and reclaimed due to lowered meat consumption.

The choice of storage technologies is where the scenarios differ the most. Scenarios that make more conservative technology choices must exclude some of the more promising storage options that are not yet commercially available. More cautious scenarios limit storage technologies to PSH, biomass and CST thermal energy storage. At the start of this research in 2010, widespread use of hydrogen as a form of energy storage was a fairly futuristic idea. However, it features in many scenarios in the literature today and will be expanded on below. Some scenarios include CAES, an established technology with half a dozen plants operating in Germany, the United Kingdom, and the United States (US Department of Energy 2014b). There are several more planned. Fthenakis et al. (2009) is a highly solar-specific scenario with 69% of all electricity generated from PV or CST. In this scenario, CAES storage is charged using surplus electricity.

Some scenarios envisage the use of hydrogen, produced by electrolysis using renewable electricity, as a substitute fuel for liquid and gaseous fossil fuels (Henning and Palzer 2014; Rasmussen et al. 2012; Jacobson and Delucchi 2011; Connolly et al. 2010; Fthenakis et al. 2009; Sørensen 2008; Lehmann 2003). Allen et al. (2013) suggest a role for hydrogen in vehicles that cannot readily be powered with electricity, such as long-haul trucks. Henning and Palzer (2014) suggest that synthetic methane could be stored in caverns or in the existing natural gas grid. Rasmussen et al. (2012) find that short-term hydrogen storage has a significant benefit in balancing electricity demand across Europe. In some of the Energy Rich Japan scenarios (Lehmann 2003), domestic Japanese energy supply can be so constrained as to require hydrogen imports. However, the broader idea of 'power to gas' – the use of surplus renewable electricity to produce synthetic gases – is now gaining acceptance, particularly in Europe, as a means of balancing electricity generation. Audi (2014) opened its first 'e-gas' plant in Werlte, Germany in 2013, producing renewable synthetic methane.

3.4 Approach

A wide variety of modelling approaches have been used to quantitatively analyse future RE scenarios. Scenarios are now becoming more detailed and sophisticated. With them, so are the modelling tools. Connolly et al. (2010) reviewed 37 energy modelling software tools. The tools were classified by their capabilities, geographic scope, energy technologies modelled, timeframe and time step. Many of the scenarios in Table 3.1 are evaluated using custom models (ie, those entries listing 'Simulation' or 'Optimisation' in the Approach column). The models are described in sufficient detail to support the work, but their implementations are rarely described, nor whether they have been released for others to use. Sørensen and Meibom (2000) used a generic Geographic Information System (GIS).

The various International Energy Agency (IEA) energy system models have a long history (Loulou and Labriet 2008). Figure 3.1 shows the relationship between

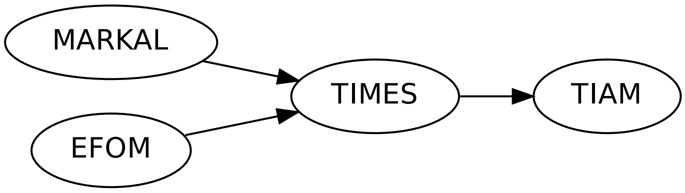

Figure 3.1: Relationship between IEA energy system models

these bottom-up, linear optimisation models. Succeeding the MARKAL[2] model is TIMES[3], which incorporates features from EFOM[4]. TIMES can model energy system development out to the year 2100, optimising for minimum net total cost (Loulou and Labriet 2008). TIMES Integrated Assessment Model (TIAM) is a global version of TIMES that divides the globe into 15 regions. These models are commonly used for modelling the energy system of an entire economy, although TIMES can be used to model a single sector like electricity (Loulou and Labriet 2008). Føyn et al. (2011) examined the potential for TIAM to model a global 100% RE scenario using its existing technology and resource database. WWF and TERI (2013) modelled a 100% RE scenario for India using MARKAL. Devogelaer et al. (2013) similarly modelled 100% RE for Belgium using TIMES with scenarios for different levels of imported electricity and biomass. Similar to TIAM, the scenarios of the Global Energy Assessment (GEA) were developed in parallel using two integrated assessment models (Riahi et al. 2012): MESSAGE[5] using 11 regions, and IMAGE[6] using a mixture of 26 regions for socio-economic modelling and high spatial resolution (0.5°) for modeling physical systems such as land-use change (Bouwman et al. 2006).

Electricity sector scenarios are typically tested using hourly dispatch models and, in more sophisticated studies, a combination of capacity expansion models and hourly dispatch (Mai et al. 2012). Nelson et al. (2012) identified the need for high resolution models that co-optimise capacity expansion and economic dispatch, and developed a tool called SWITCH[7] to model lower carbon electricity

[2]Market Allocation
[3]The Integrated MARKAL-EFOM System
[4]Energy Flow Optimisation Model
[5]Model for Energy Supply Strategy Alternatives and their General Environmental Impact
[6]Integrated Model to Assess the Global Environment
[7]Solar, Wind, Hydro and Conventional generation and Transmission Investment

futures for the Western Electricity Coordinating Council (WECC) in the United States. SWITCH is a mixed-integer linear program with a cost minimisation function. The expansion of the system is modelled until 2030.

Mai et al. (2012) input promising candidates from the high-level Renewable Electricity Deployment Systems (ReEDS) model into ABB GridView, so does not co-optimise as Nelson et al. (2012) suggest. GridView is a production cost model that simulates power system operation including hourly dispatch, ramp rate limitations of generators, minimum generator operating levels, and transmission limits. A single run using this pair of models takes around 10 hours to complete (Mai 2012). GridView examines transmission requirements between balancing areas and the requirement to extend transmission lines to connect new generation. It also considers the need to expand transmission links between the three main grids in the United States (US): Electric Reliability Council of Texas (ERCOT), WECC and the Eastern Interconnection. Chaining different models together, or soft-coupling, is a powerful technique (Schmid et al. 2013).

Where scenario objectives are sufficiently alike, tools used in previous studies can be successfully reused. The EnergyPLAN model from Aalborg University has been used to simulate 100% renewable scenarios for Denmark (Lund and Mathiesen 2009), Ireland (Connolly et al. 2010) and the Republic of Macedonia (Ćosić et al. 2012). EnergyPLAN is an input/output model that simulates one year in hourly time steps (Lund et al. 2011). Inputs include demand, RE resource data, costs and operational strategies. The model outputs include the annual energy production, fuel consumption, import/exports and total costs (Lund et al. 2011). The system can be optimised according to technical criteria or minimum cost. A multitude of supply and demand technologies are modelled including batteries, hydrogen electrolysers, CHP, residential solar hot water, electric boilers and hydrogen vehicles.

Simulations for Germany (Henning and Palzer 2014; Palzer and Henning 2014) were carried out using Renewable Energy Model-Deutschland (REMod-D), an integrated model of the electricity and heat sectors that simulates a full year with hourly time steps. The authors state that no existing software package met the requirement for a cost optimisation model of both electricity and heat. The system is optimised for least cost using the Regula-Falsi method to modify free parameters in the 11-parameter system (Henning and Palzer 2014). An advantage of the Regula-Falsi method is that it is deterministic and easily reproduced. Like other search techniques, the Regula-Falsi method can become trapped in local minima. Henning and Palzer (2014) find that many local minima exist, producing markedly different system configurations, but with similar annual costs. The authors suggest this provides the option of using additional criteria in the optimisation of the system (eg, to accommodate community preferences).

A similar cost minimisation model used by Budischak et al. (2013) is based on five parameters: generating capacity of on-shore wind power, generating capacity of off-shore wind power, generating capacity of PV, power capacity of one of three storage technologies, and the energy capacity of the storage. Each parameter has 70 possible values, based on a linear spacing from zero to the maximum feasible value, giving 70^5 (1.6 billion) possible points in the parameter space. The parameter space is exhaustively evaluated using a 3,000 node computer system with a runtime of 15.5 hours (Budischak et al. 2013).

H_2RES (H$_2$RES 2014; Krajačić et al. 2009) was developed with a focus on island power systems, but has also been used to model a national scenario for Portugal (Krajačić et al. 2011). H_2RES models demand for electricity, desalinated water, heat and hydrogen at hourly resolution. H_2RES includes generator models for wind turbines, solar PV, wave power, hydroelectricity, geothermal, biomass, fossil fuelled generation, PSH, batteries, and hydrogen storage.

Some scenarios have retained a small amount of energy supply from fossil or nuclear sources to evaluate the impact of a high penetration of renewables on the existing generation (Nelson et al. 2012; Mai et al. 2012; Denholm and Hand 2011). In a scenario of 100% renewable electricity in New Zealand, the system is simulated by eliminating the residual share of energy supplied by fossil fuels and replacing this with renewables (Mason et al. 2013, 2010).

3.5 Locations

Table 3.1 ('Location' column) gives the physical location of each scenario in the literature survey. The table groups scenarios with global, regional, national and sub-national geographic scope. Selected studies from each of these groupings are discussed briefly below.

3.5.1 Global scenarios

Several comprehensive studies have examined the potential to meet most or all of the global end-use energy demand from RE sources including by Teske et al. (2012), Jacobson and Delucchi (2011), WWF (2011) and Sørensen and Meibom (2000). The one exception is Glasnovic and Margeta (2011) which is limited to the electricity sector. Global scenarios are challenging due to the enormous scale and the difficulty of determining energy demand at fine spatial and temporal resolution. The scenarios are necessarily simplified. A common approach to reducing the complexity of the global scenarios is to divide the globe into smaller regions. Sørensen and Meibom (2000) investigate a global RE scenario for 2050 using two different supply-side options: one completely decentralised system, and another that integrates a small amount of centralised generation to assist in densely populated regions where energy demand exceeds supply (for example, urban environments with high rise residential buildings).

Jacobson and Delucchi (2011) propose two broad approaches to achieving a global 100% WWS energy system. First, end-use energy demand is reduced through energy efficiency and, where possible, by converting demands to electricity (eg, heat pumps for water and space heating, and electric vehicles). Next, for demands that cannot be easily converted to electricity (eg, shipping, aviation and high-temperature industrial processes), these are fuelled with hydrogen produced from renewable electricity.

The World Wide Fund for Nature (WWF) commissioned consultancy firm Ecofys to assess the potential to achieve 100% RE for the world by 2050 (WWF 2011). In the study, the world is divided into ten regions, which may only exchange energy within the region (eg, via transmission lines). Importantly, the study advocates strict standards for the production of bioenergy in order to minimise disruption to existing agricultural land and areas of high conservation value.

The International Institute for Applied Systems Analysis (IIASA) completed the large Global Energy Assessment (GEA) of energy system pathways to achieve climate stabilisation (Riahi et al. 2012). The details listed for this scenario (Riahi et al. 2012) in Table 3.1 correspond to only one of 60 pathways examined, namely a scenario from the GEA-Efficiency group with an emphasis on energy efficiency and restrictions on the availability of other options such as carbon capture and storage (CCS) and nuclear power. The 90% RE target listed in the table is not an explicit target in this scenario, but is the share of RE found to achieve the climate objectives.

3.5.2 Regional scenarios

Regional scenarios to date focus on the European Union (EU) and northern Europe due to harmonised climate and RE policies within these blocs, close proximity of countries, existing grid interconnection, and the ability to trade RE across a larger geographic area. The EU is motivated to adopt RE due to fossil fuel imports exposing the EU economy to rising and volatile fuel prices. Additionally, the EU is becoming sensitive to the risks of supply shocks. Energy independence is now viewed as an important goal as well as climate mitigation (Zervos et al. 2010). Schellekens et al. (2010) include imported CST electricity from Northern Africa in a European scenario. Zervos et al. (2010) present a 100% RE scenario for Europe produced by members of the European Renewable Energy Council (EREC) and is therefore likely to err on the optimistic side in terms of technology development and potential cost reductions.

Sørensen (2008) examined the potential for northern Europe to use RE for all final energy. The study included Denmark, Norway, Sweden, Finland, and Germany. Simulations performed at individual country level showed that all of the Nordic countries could easily meet their demand from renewable sources due to plentiful wind, hydro and biomass resources, but that Germany could not due to limited renewable resources and a much larger population. A subsequent simulation permitting energy trading across borders found that Germany could meet demand through the importation of electricity and hydrogen.

3.5.3 National and sub-national scenarios

National scenarios examine the possibilities for RE at a more localised level and, in the case of scenarios published in reports, may offer insights for specific groups such as local RE industries and decision makers. Energy policies are typically enacted at the state or national level, so national scenarios can be highly relevant to decision makers. Furthermore, by narrowing the geographic scope of the study, scenarios can be completed with a higher degree of resolution and detail.

National circumstances – including RE resource types and availability, population, industries, and energy use patterns – vary by country. Reviewing the literature of national scenarios serves three purposes. First, it builds an increasing body of evidence about the feasibility of 100% renewable electricity using a variety of modelling tools and data sets. Second, it enables the research community to share techniques for evaluating and optimising local scenarios. Third, it covers a diversity of RE mixes. A subset of the national scenarios from Table 3.1 are briefly described below.

Germany

There is much interest in RE and carbon mitigation scenarios for Germany due to the Energiewende (Section 2.4.2) and legislated targets for high penetrations of RE in the grid by 2050. Schmid et al. (2013) compared 10 German mitigation scenarios (published in German) and found that wind is the most important technology in the scenarios surveyed, accounting for 55–70% of annual electricity generation. Biomass played an important role (10–30% of generation) and, due to a relatively poor solar resource, PV contributed just 3–16%. Of the scenarios analysed by Schmid et al. (2013), imports from other European countries ranged from 11–25%, depending on the assumptions.

A German scenario for near-100% RE in the electricity and heat sectors has been completed by Henning and Palzer (2014). The scenario allows for limited energy exchanges with neighbouring European countries and limited use of fossil fuel for high efficiency applications (eg, electricity from combined cycle gas turbines). A coarse estimate of transmission costs is included. With the assumed costs, the authors find that the annual cost of the scenario would be € 111 billion (A$ 170 billion) per year, estimated to be comparable to current annual costs in Germany. A number of significantly different system configurations produces a range of costs of € 111–120 billion per year. The German Advisory Council on the Environment (2011) scenario used the high resolution REMix model from the German Aerospace Center (DLR). The model consists of two components: RE resource data at high spatial resolution in hourly time steps, and a linear optimisation to solve for minimum costs. The model includes a direct current (DC) powerflow approximation of the transmission network, storage (PSH, compressed air, hydrogen production and batteries), heat demands and production, and electric transportation. REMix is not available to the public.

India

WWF and TERI (2013) produced a 100% RE scenario for India. The scenario projects a transition to the year 2050 and aims for 100% RE supply of final energy. A 100% RE scenario for a developing country is in contrast to most 100% RE scenarios, which consider industrialised countries with established energy systems. The transition includes the need to substantially and sustainably increase energy supplies to improve the living standards of many. This work reinforces the importance of strong policies in countries where per capita emissions are currently low due to lack of access to energy services.

Japan

One of the earlier and more radical 100% RE scenarios is *Energy Rich Japan* (Lehmann 2003). Lehmann (2003) identifies a number of factors that make Japan one of the more difficult regions of the world to implement 100% RE and posits that if this can be achieved in Japan, it will be much easier to achieve elsewhere in the world:

- a small land area, much of which is mountainous;
- a large population (127 million people, although declining);
- an industrial economy with significant electricity demand; and
- limited potential to exchange electricity with other countries.

Lehmann (2003) only examines the technical feasibility of RE. Six scenarios are produced: 50%, 75% and 100% of demand supplied by RE, with and without the effect of the forecast decline of 27 million people by 2050. Some scenarios rely on imported RE in the form of hydrogen. A premise of the study is that no demand side changes are made which would reduce industrial production or a decline in living standards. Actual demand data were not available, so demand was estimated from load curves.

New Zealand

Sovacool and Watts (2009) point out that New Zealand had a 100% renewable electricity system once before – in the 1950s – based on hydroelectricity supplemented by geothermal. Nowadays New Zealand generates the majority of electricity from hydroelectricity with approximately 32% from fossil fuel sources. The potential to return to 100% renewable electricity supply in New Zealand has been evaluated using a novel technique (Mason et al. 2013, 2010). Using six years of historical electricity demand and generation data from existing generation sources, the fossil fuel generators were removed from the data. The model then optimises the system to eliminate this shortfall using wind power at varying degrees of penetration.

United Kingdom

Allen et al. (2013) present the third *Zero Carbon Britain* (ZCB) publication on scenarios for complete carbon neutrality in the United Kingdom by 2030. It is unique among the scenario studies in the breadth of its analysis of the whole economic system. Allen et al. (2013) find that, after fuel switching from fossil fuels to renewable electricity and renewable fuels, emissions of 45 Mt CO_2-e per year remain and are difficult to eliminate. These emissions are neutralised with carbon sequestration: planting new forests, restoring peat lands, biochar, and locking up carbon in timber structures like buildings.

ZCB has some characteristics that stand it apart from all other studies. Most scenarios address the technological aspects of emissions intensive energy use, but Allen et al. (2013) recognise the scope of behaviour changes that will be required. ZCB emphasises whole-of-economy approaches, economic benefits, health benefits and well-being. The main shortcoming of the ambitious ZCB scenario is that there is no modelling of the costs.

United States

Scenarios have examined the United States at the level of interconnected systems. Budischak et al. (2013) have cost-optimised a high renewables system for the Pennsylvania-New Jersey-Maryland (PJM) Interconnection in the north-east US. The integration of higher levels of wind power has been examined for the US Eastern Interconnection (National Renewable Energy Laboratory 2011). Likewise, wind and solar integration has been examined for the WECC (National Renewable Energy Laboratory 2010). Jacobson et al. (2013) have built on earlier work at a global scale constructing a 100% RE scenario for the state of New York. Almost all energy is generated within the state borders and off the Atlantic coast using off-shore wind turbines.

Two renewable electricity scenarios were reviewed for the continental United States: Fthenakis et al. (2009) and the National Renewable Energy Laboratory (NREL) Renewable Electricity Futures Study or RE Futures (Mai et al. 2012). RE Futures is a highly detailed analysis of increasing levels of renewable electricity into the US electric sector. RE Futures is the most detailed and comprehensive analysis of high penetration RE scenarios undertaken. Over 100 people contributed to RE Futures from 35 organisations including US national laboratories, industry and academia. RE Futures can be considered the state of the art for simulations of renewable electricity at the scale of a large nation.

RE Futures considered future electricity scenarios for the continental United States in 2050 at hourly resolution. The study examines renewable penetrations from 30% to 90% with a focus on the 80% level. Only RE technologies commercially available in 2010 are included: on-shore wind, off-shore wind, PV, CST, hydroelectricity, hydrothermal geothermal, biomass, and biomass co-firing with pulverised coal. Other low carbon generation options such as nuclear power and CCS are excluded.

Mai et al. (2012) include a detailed set of sensitivity analyses:

- A baseline, or reference, scenario.
- Exploratory scenarios of 30% to 90% renewable generation with two different assumptions about the rates of performance and cost reductions in renewable technologies: incremental technology improvement (ITI) and evolutionary technology improvement (ETI).
- Six scenarios with 80% renewable penetration. All assume a lower level of future electricity demand.
  - three scenarios based on different rates of technological progress for performance and cost reductions: no technological improvement (NTI), ITI and ETI. The NTI assumes no improvement over time, the ITI assumes a cautious view of improvement, and ETI assumes more significant progress, but does not include any significant breakthroughs.
  - three scenarios where an aspect of the scenario is constrained: constrained transmission, constrained power system flexibility and constrained resource availability. All of these scenarios use the ITI assumptions.
- Several scenarios using higher projected electricity demand in 2050. The baseline scenario and 80% RE scenarios are repeated with 30% growth in electricity demand.

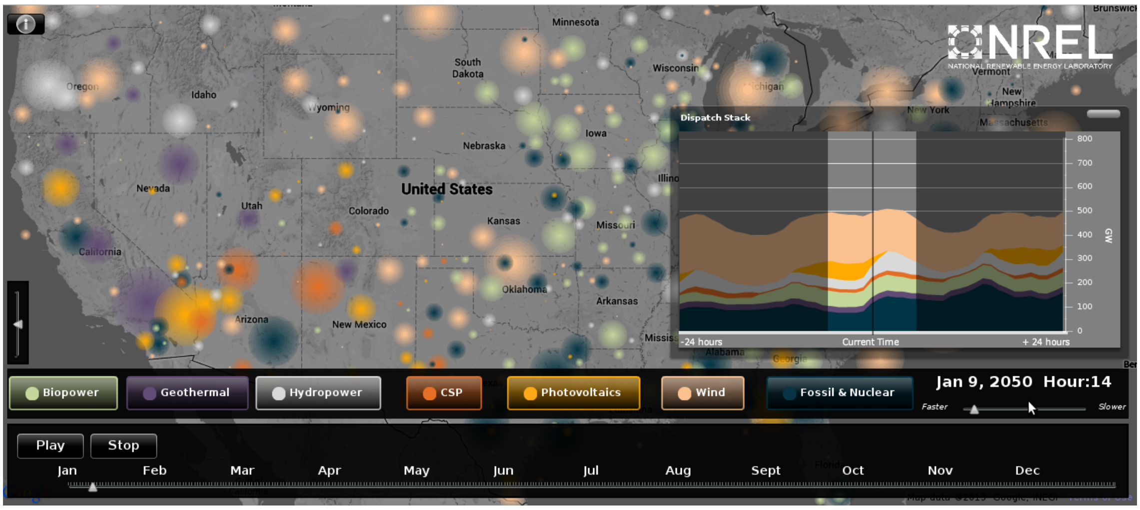

Figure 3.2: Screen capture of Renewable Electricity Futures Study visualisation tool showing hourly operation in 2050; dispatch stack shown inset (National Renewable Energy Laboratory 2014)

- Two fossil fuel scenarios using an 80% RE scenario and the baseline scenario with changes in fuel price and improvements in fossil-fuelled technology costs and performance.

NREL has published the data and key results from RE Futures on a website[8] that allows users to visualise the system as the simulation proceeds. Figure 3.2 shows a screen capture of hourly dispatch operation in 2050. Mai et al. (2012, p. 2-25) conclude that the high penetration RE scenarios 'would be demanding but achievable'.

Australia

It is appropriate to devote particular attention in this chapter to previous scenarios for Australia. Australia has some unique characteristics which are likely to make scenarios for the country quite different to other localities. First, the National Electricity Market (NEM) covers a very large geographic area across multiple climate zones from the tropical far north to cool temperate climates in the south. Australia has a large, sparsely populated land mass and massive RE resources from a variety of sources (Geoscience Australia and ABARE 2010). The NEM

[8] http://www.nrel.gov/analysis/re_futures/

is large, but is also an island electricity system and is currently unable to trade electricity with Western Australia or neighbouring countries.

Zero Carbon Australia Stationary Energy Plan The climate advocacy organisation Beyond Zero Emissions published the first scenario of this kind for Australia in 2010 called the *Zero Carbon Australia Stationary Energy Plan* (Wright and Hearps 2010). The plan describes a single scenario of Australia moving to 100% RE for all stationary energy use by 2020. Like WWF (2011) and others, this plan emphasises widespread electrification of transportation, heating, and other uses which can easily be powered by electricity.

In the scenario, the locations of central receiver CST systems with 17 hours of thermal storage, wind farms, and transmission lines were explicitly chosen. The system was modelled at half-hourly resolution over two years (2008 and 2009). Wind power was determined by scaling up published half-hourly wind farm generation data. There is no PV generation included in the scenario. The CST model estimates heat collection using daily solar exposure data from the Bureau of Meteorology and then dispatches at half-hour resolution based on storage levels. This is a legitimate approach since the storage capacity is so large and has the advantage of allowing the dispatch of the CST plants to be matched to the frequency of other time series data in the simulation.

The plan includes several striking but potentially expensive ideas such as:

- connecting Western Australia to the rest of the NEM with a transmission line from east to west across the vast Nullarbor Plain;
- obtaining 60% of electricity from CST central receiver systems, with the balance from wind power, existing hydro and biomass; and
- co-firing the CST power stations with biomass to ensure system reliability during long periods of low solar irradiance.

The choice of CST, the RE technology with the highest capital cost of the commercially available technologies, for such a large share of generation is remarkable.

It is possible to speculate that Beyond Zero Emissions chose to use CST in this way to demonstrate that CST could be operated to supply 'baseload' power, or based on the belief that the cost of this technology would fall significantly before 2020. Co-firing CST with biomass is an interesting idea that requires the biomass to be transported by rail to the CST stations. An alternative is to co-locate CST plants in regions with biomass resources and this is an active area of research in Australia (Peterseim et al. 2014). This approach has the advantages of requiring minimal modification to the CST plant and allowing the existing CST steam turbine to be operated at higher utilisation.

The main limitations of Wright and Hearps (2010) are that only one scenario with a limited mix of RE technologies was developed, and no economic optimisation of the scenario was performed. Since 2010, the price of distributed PV has fallen significantly and the previous assumption that CST would be cheaper than PV no longer holds. It would be valuable for Beyond Zero Emissions to update this plan using some revised assumptions and more recent cost data. Finally, the choice of 2020 as the target year for the transition attracts scrutiny for being unrealistic given the labour, material, and capital requirements, and the fact that such a transition would 'strand' most of the power generation assets in Australia.

Victoria Huva et al. (2012) bring a unique perspective by using an NWM to optimise a fleet of wind and CST generators in the state of Victoria. The state is treated as a 'copper plate'. Rather than use weather observations to estimate renewable generation, Huva et al. (2012) use the output from the Weather and Research Forecasting (WRF) model, which has the advantage of giving high spatial (1.5 km) and temporal (30 minute) resolution uniformly across Victoria. Huva et al. (2012) note that using an NWM rather than the observational network of weather data enables a much greater number of locations to be included in the optimisation with further reduced variability from the renewable sources.

A gradient optimisation is used to find the optimal capacities of wind and solar generation sites to maximise wind and solar generation (and hence, minimise gas-fired generation). A screening process was used to reduce the grid points to a subset suitable for wind and solar generation. A full year was not simulated, however, due to the high computational workload. Only four seasonal snapshots of five days each (a total of 20 days at half-hourly resolution) are used. A statistical model of demand was used to estimate demand from ambient temperature. This application of least cost optimisation begins to answer questions about the siting of future solar and wind generation and how spatial and temporal diversity can reduce variability. The study confirms that the spatial diversity of wind in south-east Australia is much greater than for solar radiation. Furthermore, the work demonstrates that with just two variable generation sources (the CST has no storage), that only a small amount of generation from gas-fired plant is required.

AEMO 100% Renewables Study Following the 2010 Australian federal election, a Multi-Party Climate Change Committee (MPCCC) was formed in an attempt to reach a cross-party agreement on climate change mitigation policy for Australia. The agreed package of policies included commissioning the power system operator, the Australian Energy Market Operator (AEMO), to undertake a detailed techno-economic feasibility study of 100% renewable electricity in the NEM. AEMO already performs short-range scenarios for advising electricity industry participants on investment planning (AEMO 2013b). The request from the Government was to extend this planning to 2030 and 2050 to evaluate the technical feasibility and cost of a 100% renewable electricity system using similar analyses that are applied today.

A draft report of the AEMO study was released in May 2013 and a final report was released in September 2013. The AEMO study was well received as an authoritative statement by the power system operator about the technical feasibility of 100% renewable electricity. The expertise and experience of AEMO appeared to be held in high regard. The AEMO final report was released shortly after the second of two papers was published by the author (Elliston et al. 2012a, 2013).

The AEMO study is the closest scenario to the work presented in this thesis. It is difficult to compare the AEMO work with the present research without reading further. Hence the AEMO study will be compared in detail in Chapter 9.

3.6 Scenario scope and resolution

3.6.1 Geographic scope and spatial resolution

The literature contains scenario studies undertaken with a variety of geographic scopes and spatial resolutions. The survey in Table 3.1 contains seven global scenarios, five regional scenarios (all for Europe), 17 national scenarios, and seven sub-national scenarios. The smallest sub-national geographic areas considered are New York state (Jacobson et al. 2013) followed by Victoria (Huva et al. 2012). Scenarios with much larger geographic scope (eg, the globe) tend to have a correspondingly larger spatial resolution by necessity. Some global scenarios use a regional subdivision of the globe (Sørensen and Meibom 2000), while Jacobson and Delucchi (2011) evaluate the annual average wind and solar energy resources at 1.5° resolution. Spatial resolution is a dominant factor in the computational complexity of scenario modelling. Doubling the resolution of two-dimensional spatial data potentially increases the simulation workload four-fold. It can also be difficult to obtain high quality data in all of the required domains at the same spatial resolution. Depending on the spatial resolutions and type of data involved, it may not be valid to average data to alter the spatial resolution.

The majority the scenarios in the literature review have been developed with the geographic scope of a single country. Since 2011, a multitude of scenarios have been produced for countries all over the world. These may have been motivated by a desire to demonstrate the potential of RE in a home country or to guide national RE policies. National scenarios may use national resolution (ie, no subdivision of the area) or sub-national spatial resolution (eg, Mason et al. 2013; Mai et al. 2012; Esteban et al. 2010; Lehmann 2003). This is usually achieved by dividing the country into smaller geographic regions, but can also be performed by dividing the country into spatial grids when appropriate gridded data are available (eg, German Advisory Council on the Environment 2011; Heide et al. 2010, and associated papers).

Scenarios using meteorological outputs from NWMs can employ a much higher spatial resolution and greater coverage without relying on an observation network

(Huva et al. 2012). This allows scenarios to potentially include areas off coastlines for off-shore wind farms. Generation from wind or solar generators, for example, can be estimated for each grid cell (Nelson et al. 2012; Huva et al. 2012). NWM data from a European weather model at 48–50 km spatial resolution is used by Rasmussen et al. (2012) and Heide et al. (2011, 2010). Similarly, Huva et al. (2012) use wind and solar data at 1.5 km resolution for the Australian state of Victoria, although the authors report a high computational workload at this resolution, necessitating a reduced temporal range (discussed below).

3.6.2 Temporal range and resolution

The scenarios in the literature employ time series data (eg, demand data, weather data) over different timeframes and at different resolutions. Most commonly, scenarios model a single year. Where data are available, scenarios may consider a wider range of years: two years (Wright and Hearps 2010), three years (Mason et al. 2010), six years once three more years of data became available (Mason et al. 2013), eight years (Heide et al. 2010), and ten years for ZCB (Allen et al. 2013). Ten years is the longest simulation completed to date. Mason et al. (2013) note that using six years of data for New Zealand countered criticisms that the earlier study (Mason et al. 2010) avoided a dry year and did not meet statutory security of supply risk criteria. The model was modified and the six-year data set updated to include the lowest rainfall year since 1931. Security of supply continued to be maintained (Mason et al. 2013).

A complication of scenarios using data with high spatial resolution is that temporal range may need to be sacrificed to keep the simulation time reasonable. Huva et al. (2012) used a synthetic time series of just 20 days spliced together (five days from each season) due to the high computational cost of producing high resolution NWM data. A longer range of years gives greater confidence in the results as more extreme weather events are likely to be captured in the meteorological data.

Existing studies have also employed a number of different temporal resolutions. In scenarios with lower temporal resolution, which tend to be those with wider geographic scope, energy demand is matched to available RE generation on an annual basis (Teske et al. 2012; WWF 2011; Jacobson and Delucchi 2011; Schellekens et al. 2010). Scenarios at annual resolution can be evaluated without detailed simulation and offer the ability to use more easily accessible RE resource and demand data as either annual energy or average power.

Modelling the electricity sector requires higher temporal resolution to demonstrate that supply can be matched instantaneously with demand at all times and, if modelled, all locations across the network. With the exception of Schellekens et al. (2010) and Sustainable Energy Now (2013), which compare annual RE potential with annual electricity demand, all of the electricity-only scenarios surveyed use hourly or half-hourly resolution.

Hourly resolution can be considered an acceptable resolution at present. However, simulation at hourly resolution does not fully capture events that occur on shorter time scales. Half-hourly resolution is preferable if the data are available, as this only requires twice as many simulation steps. No 100% renewable electricity scenarios have yet been modelled at higher than half-hourly resolution. To do so will require higher frequency meteorological data and RE generation models capable of modelling generator output at the required frequency. The System Advisor Model (SAM) PV model, for instance, currently only models PV output at one-hour intervals.

A useful temporal resolution between annual and hourly resolution can be achieved using *load blocks*. In simulations employing load blocks, longer time steps (eg, four or six hours) are used. Load blocks can be selected from different times of the day, months, seasons, or years to provide a snapshot of demand and renewable generation conditions at different times throughout a longer time series. This is useful in developing simulations that run quickly, having a small number of simulation steps. For example, in Mai et al. (2012), the ReEDS tool is used to perform high-level supply and demand balancing using 17 time slices: four time slices per day per season and an additional time slice for the summer peak demand period. Using only 17 time steps allows computing time to be devoted to simulating at higher spatial resolution. Load blocks are also employed in Devogelaer et al. (2013), Føyn et al. (2011), and Lehmann (2003). Nelson et al. (2012) combine a capacity expansion model with an economic dispatch model which runs over 576 hours: four investment periods spaced between 2014 and 2030, 12 months per investment period, 2 days per month, and 6 non-contiguous hours per day. Additional post-optimisation checks of system reliability are performed using 100 weeks of hourly data from 2004 and 2005.

3.7 The role of transmission networks

Some scenarios of electricity power systems use a simplifying assumption that the area of interest can be treated as a 'copper plate'. That is, power can flow unconstrained from any generation site to any load site as if there is an infinite capacity transmission network spanning all possible locations of generators and loads. This simplification is helpful when resource and load data have poor spatial resolution and avoids the need to consider power flows in transmission networks. However, once models have a sufficiently high spatial resolution, it is possible to represent transmission networks. Expanded transmission networks are anticipated to play a critical role in 100% renewable electricity systems, however this will depend on the relative development of distributed and centralised generation technologies. Studies such as Rodríguez et al. (2014), Mai et al. (2012), and Tröster et al. (2011) anticipate the need for much larger transmission capacities than are encountered today. This is evident from the screen capture in Figure 3.3 showing some transmission links with power flows exceeding eight gigawatts in one RE Futures scenario.

The European grid has been studied closely due to the close proximity of European countries with ambitious long-term RE targets and diversity of RE sources. Schaber et al. (2012b) use a high resolution model of the European power system (83 regions with 33 being off-shore, and 48 representative weeks of hourly data taken from the Heide et al. (2010) eight year data set) to investigate the merit of an overlay high-voltage transmission network to aid the integration of variable renewable energy (VRE). Schaber et al. (2012b) conclusively demonstrate the eco-

Figure 3.3: Screen capture of Renewable Electricity Futures Study visualisation tool showing power flow in 2050; legend shown inset (National Renewable Energy Laboratory 2014)

nomic benefits of grid extension in a highly renewable European power system. In a case study of 60% penetration of VRE, grid extensions reduce the required VRE generating capacity, dispatchable generating capacity, over-production, supply/demand mismatch, and overall costs. The model has also been applied to a study of electricity market economics in Europe in 2020, with only partial renewable supply (Schaber et al. 2012a). It was found that in the short-term, increased transmission capacity reduces the ramping of thermal generation as the balancing duty can be shared by a wider range of more flexible thermal generators elsewhere in the network (Schaber et al. 2012a).

Models of transmission networks in electricity-only scenarios are still relatively simple at this stage. Transmission networks are, at best, analysed with DC optimum power-flow models. Transmission networks may be constrained (Nelson et al. 2012; Mai et al. 2012) or unconstrained with the maximum flows noted (Rodríguez et al. 2014). Rodríguez et al. (2014) model the European grid using a 30-node network (one node per country) and unconstrained transmission links. An unconstrained version of the model determines network requirements, similar to the approach taken in this thesis (Chapter 6). By imposing transmission constraints for a small number of hours per year (2% of total hours), Rodríguez et al. (2014) find that this reduces the total transmission capacity from 11.5 times the current network capacity to 5.7 times. This demonstrates that full system optimisation including transmission is important for 100% RE scenarios.

Tröster et al. (2011) modelled European transmission requirements in 2030 and 2050 using a simplified 224 node network and the generation mix specified for the EU-27 by Teske et al. (2010). An iterative process performed the lowest cost grid upgrades in a minimalist fashion. In this model, preference was given to local generation dispatched in each region to minimise line flows (Tröster et al. 2011). This had the undesired effect of sometimes favouring local conventional generation and increasing curtailments (eg, of wind power) elsewhere in the network. The simulations were modified so that variable generation was always dispatched first, regardless of its location in the network. This has a significant effect on reducing curtailments across the network and reducing the share of conventional generation.

Tröster et al. (2011) found that grid reinforcement in Europe will be required in the future between Spain and central Europe via France (for PV, CST and wind power), from central Europe and Norway to Great Britain, from Italy to central Europe (for PV and wind power) and, optionally, from Northern Africa to central Europe (for CST). The system was found to be reliable, even under extreme weather conditions. Transmission and storage are competing mechanisms for managing variable generation. Tröster et al. (2011) conclude that transmission is always much cheaper than using storage to reduce curtailments. In the long run, the balance will be dictated by the economics and social acceptance of large transmission lines.

Transmission projects have long planning periods, and in some parts of the world, poor social acceptance (Schaber et al. 2012a). Schellekens et al. (2011) identify grid expansion as the most important barrier to the successful transition to 100% renewable electricity in Europe. Overall, the literature indicates that transmission projects in Europe are highly contentious. There is a trade-off that can be made between more local generation (eg, PV) and less transmission capacity, or more large-scale generation sited in areas further from the loads and more transmission capacity (Tröster et al. 2011). Due to the complexity involved, none of the scenarios considered future modifications to the distribution network.

3.8 Generator flexibility

An idea explored in early research on integrating higher levels of RE into electricity systems was that variable generators could be organised to substitute for conventional 'baseload' power stations. Using a numerical probabilistic model Martin and Diesendorf (1980) showed that, at low penetration of wind power, the capacity credit of wind power is approximately equal to the average wind power. This was repeated analytically by Haslett and Diesendorf (1981). For large penetrations of wind power, the capacity credit of wind power tends to a limit (Martin and Diesendorf 1980) that is proportional to the probability of non-zero wind power (Haslett and Diesendorf 1981). Martin and Diesendorf (1982) studied the economic value of wind power in an optimal mix of wind power and conventional power stations. With a small amount of additional peak load capacity, operated infrequently, the system operates with the same loss of load probability as the pre-wind system. This peak load capacity, having a low capital cost and low annual operating costs, can be considered to be reliability insurance with a low premium (Martin and Diesendorf 1982). Denholm et al. (2005, p. 1903) noted that combining wind energy with battery storage yields generation that is 'functionally equivalent to a baseload coal or nuclear power plant'. Mills and Keepin (1993) examined the potential for solar thermal electricity to serve baseload demand. Mills (2010) has since refined this view, stating that a mix of flexible and inflexible generation is needed. In this context, *inflexible* means less controllable (eg, PV), rather than having the limited operational flexibility of a coal-fired or nuclear power station. This view of using high penetrations of variable generation in conjunction with forms of flexible, dispatchable generation (eg, gas turbines, hydro, CST, batteries) is now gaining broad acceptance in the RE literature (Diesendorf 2014; Pregger et al. 2013; Mai et al. 2012; Wright and Hearps 2010).

In NREL work prior to the RE Futures study in 2012, Denholm and Margolis

(2007) investigate three options to increase the penetration of PV beyond minimal levels: increasing the operational flexibility of conventional generators, load shifting to improve supply and demand matching, and energy storage. The authors found that increasing the operational flexibility of conventional generators is necessary to increase penetration of variable generation, but that some combination of the other options will be required to address natural mismatch in demand and PV generation. The paper introduces the concept of *flexibility factor* for high penetration renewable electricity systems. The flexibility factor is the fraction of generation – of all types – that can rapidly respond to changes in demand. Energy storage is found to add significant benefits. For example, a modelled combination of 11 hours of storage and an 80% flexibility factor enabled PV to meet 50% of electricity demand (Denholm and Margolis 2007). Cochran et al. (2014a) document a case study of a coal-fired power station in North America that has achieved greater operational flexibility through plant modifications and changes to operating practice.

3.9 Demand modification

A difficulty with setting a scenario reference date decades into the future is predicting demand factors such as population growth, geopolitical factors (eg, the dramatic collapse of the Soviet Union), income growth, and unexpected technological shifts. Over the past 50 years, reliable forecasts of the most basic energy industry variables such as primary energy consumption and the price of oil has been shown to be extremely difficult (Bezdek and Wendling 2002). This brings substantial uncertainty into the picture.

The scenarios in Table 3.1 indicated in the 'Demand' column employ two main approaches to modifying demand to assist in the transition to 100% RE:

1. energy efficiency measures in areas such as buildings, water heating, and lighting to reduce overall demand, so-called 'powering down' (Allen et al. 2013); and

2. electrification of existing non-electricity services – García-Olivares et al. (2012) envisage a complete electrification of society. This may increase electricity demand, but significantly reduces total primary energy demand through the higher efficiency of machines such as electric vehicles and heat pumps (Allen et al. 2013; Jacobson and Delucchi 2011).

Depending on the chosen assumptions, the scenarios may have higher or lower demand in the future. Generally, scenarios considering final energy assume significant reductions in total energy. In scenarios employing widespread electrification, demand may increase as a result of the electrification of other sectors. In Jacobson and Delucchi (2011), electricity demand increases from 20% of final energy to 50%. However, electrification of these sectors usually offers an easier path to renewable energy than substituting fossil fuels with renewable fuels. This step also introduces potential loads that can be interrupted to assist with electricity supply and demand balancing (Allen et al. 2013).

Zero Carbon Britain (ZCB) is the most holistic of all scenarios surveyed (Allen et al. 2013). ZCB proposes various means of reducing transportation energy demand: modal shifts to walking, cycling, car pooling and the replacement of domestic air travel with high-speed rail (Allen et al. 2013). Biofuels are promoted for a diminished number of international flights. Freight transport is shifted from road to rail. Allen et al. (2013) optimistically anticipate a 78% reduction in transportation energy.

3.10 Costs

Around half of the studies reviewed examine the cost of the scenarios and most of these have been published since 2011. There are two explanations for this. First, reliable cost data for a range of RE technologies are only recently available. Second, only once scenarios become sufficiently specific and the RE technologies they use are sufficiently mature, does it become possible to reliably calculate costs. The costs of some RE technologies are still highly uncertain and are constantly being revised. Recent reports of cost developments have been produced for

CST (Lovegrove et al. 2012; International Renewable Energy Agency 2012a), PV (Feldman et al. 2012; International Renewable Energy Agency 2012b), wind power (Lantz et al. 2012; International Renewable Energy Agency 2012c), and a range of generation technologies in the United States (Energy Information Administration 2013) and Australia (Bureau of Resources and Energy Economics 2012a).

In countries that are dependent on fossil fuel and uranium imports, the future cost of fuel is also highly uncertain. Pregger et al. (2013) believe that RE technology costs are therefore less uncertain in the long-term because, with the exception of bioenergy, they consume no fuel. Schmid et al. (2013) highlight the difficulties of comparing costs between scenarios: different modelling approaches, non-uniform treatment of costs, and incomplete reporting of costs and assumptions.

Scenario studies that calculate costs express them in two main ways. Studies such as Wright and Hearps (2010) strictly consider capital costs (in this case, with a short ten year deployment plan), which discounts operating and maintenance (O&M) costs and replacement costs. The other approach, particularly used in electricity-only scenarios, expresses costs in dollars per MWh averaged over annual generation (Mai et al. 2012) or as an impact on retail tariffs in cents per kWh (AEMO 2013a). This is useful for making comparisons with current-day electricity systems.

Jacobson et al. (2013) present a novel way of thinking about the costs of 100% renewable systems: the payback time of the system in terms of (i) air pollution costs; (ii) plus climate change damage; and (iii) plus electricity sales at no profit or at 7% profit. In a scenario for the state of New York, Jacobson et al. (2013) consider the impacts of the scenario on state tax revenues, noting that alternative taxation measures will need to be found.

A surprising finding from reviewing the literature is that scenarios examining 100% renewable electricity in detail, and using recent cost data, produce costs that are all in approximate agreement (around US$100–150 per MWh). Mai et al. (2012) produce costs with a fairly narrow range of uncertainty; one 90% renewable scenario estimates wholesale prices in 2050 of US$109–140 (present day dollars). Another consistent result is that the costs of expansive, high capacity transmission networks do not significantly add to the costs of the scenarios.

3.11 The need for the present thesis

The literature contains a large body of evidence suggesting that 100% RE for electricity or final energy is technically feasible at a range of geographic scales from small islands to the entire world using an array of RE technologies, many of which are commercially available now. As noted in Chapter 1, Australia has some characteristics that make the operational and economic feasibility of 100% renewable electricity likely to be rather different to other locations: a large land mass, outstanding RE resources, and a pattern of highly urban settlement. It is therefore necessary to undertake such a study for the NEM. For Australia, existing scenarios are less developed than the more detailed studies originating from Europe and the United States. The AEMO 100% Renewables Study, discussed in Chapter 9, advances our understanding of 100% renewable electricity in the NEM, and was released after most of the work in this thesis was published.

The *Zero Carbon Australia Stationary Energy Plan* (Wright and Hearps 2010) simulated a single scenario for the whole Australian continent over two years at half-hourly resolution. The scenario makes some rigid technology choices, does not explore the effect of different assumptions on system reliability and costs, and did not perform an economic optimisation. Huva et al. (2012) have performed a least cost optimisation in one region of the NEM (Victoria) using only solar and wind generation at a high spatial resolution. This thesis fills a gap in the literature by undertaking a study for the NEM that is less ambitious in scope than earlier work, more cautious in approach and assumptions, and optimises the system for lowest cost. Scenarios simulated at an appropriate level of detail are suitable for optimisation and can contribute to our understanding of the operational and economic challenges of 100% renewable electricity in the NEM.

Some of the existing studies in the literature include a reference scenario, although these differ widely in their definition. There are no reference scenarios published for the NEM under similar assumptions to a 100% renewable electricity scenario (ie, near-zero operational emissions). Typically, a reference scenario represents the 'business as usual' case relevant to the locality, although Schmid et al. (2013) note the particular difficulties in establishing a reference scenario for Germany, where 'business as usual' is highly uncertain due to fuel price volatility, climate policy, and abrupt changes in nuclear energy policy. However, with plausible assumptions and sensitivity analysis of uncertain variables, it is possible to devise a range of alternative scenarios that can be compared with a 100% renewable electricity scenario. To the author's knowledge, there are no costed scenarios, apart from the present author's, based on the optimal mixes in the NEM of:

(i) a like-for-like replacement of the current coal-fired and gas-fired generation with modern, efficient plant;

(ii) a medium-carbon scenario almost exclusively based on gas-fired generation;

(iii) coal with CCS plus open cycle gas turbines (OCGTs); and

(iv) combined cycle gas turbines (CCGTs) with CCS plus OCGTs.

It is apparent from the literature review that there is limited agreement on what the capabilities of a model for developing and evaluating 100% RE scenarios should be, although there is more similarity among the electricity sector-only models. A major problem at present is that new modelling tools continue to be developed because the profusion of existing tools are either (i) proprietary or costly (eg, GridView), (ii) only available through paid consultancy (eg, SimREN), or (iii) not available under an open source license that permits a user to adapt the software to their purposes (eg, SAM, ReEDS, EnergyPLAN). A way to overcome this predicament is to develop a sufficiently general model and release the software with an open source license. It is the author's hope that the model presented in the following chapter, and used throughout this thesis, meets the needs of other users.

Chapter 4

Model

This chapter describes the design and construction of a model for simulating 100% renewable electricity systems. The examination of radically different electricity supply systems necessitates computer simulation[1]. As with computer simulations of any kind, a trade-off must be made between computational effort and simulation fidelity. A system that is modelled in too much detail may add little insight and increase the computational effort such that simple experimentation becomes laborious. An overarching principle of the model is that it only simulates the required level of system behaviour. The model was developed solely by the author for this research and draws upon freely available libraries of supporting code.

Section 4.1 introduces the model design and gives the rationale for certain design objectives and decisions. Section 4.2 describes the computing environment used for developing and running the model. The simulation tool has three components and these are documented in the succeeding sections: a framework that supervises the simulation and is independent of the energy system of interest (§ 4.3), a library of simulated power generators (§ 4.4), and a large integrated database of historical meteorology and electricity industry data (§ 4.5). Section 4.6 presents a transmission model that was added to the model for approximat-

[1]The Kombikraftwerk project at the Fraunhofer Institute for Wind Energy and Energy System Technology is progressing beyond modelling of 100% renewable electricity systems using a test rig with a number of renewable generators sited around Germany (discussed in Chapter 9).

ing transmission network costs. Section 4.7 outlines how a genetic algorithm was then overlaid on the simulation framework, running the simulation many times to search for system configurations of least cost. This is the basis of the economic modelling presented in Chapters 6 and 7. Finally, Section 4.8 describes a software utility developed by the author to generate data files of actual weather observations for the simulation of certain renewable technologies.

4.1 Model design

The following sections provide the rationale for certain objectives and decisions that apply to both the model design and its implementation.

4.1.1 Scenario assumptions

At the start of this research in 2010, the idea of 100% renewable electricity was very controversial in Australia and it remains so, to a lesser degree, today. Consequently, an aim of this research was to develop scenarios based on as few assumptions as possible. Where assumptions were necessary, it was desirable to be conservative in the framing of these assumptions. The model was therefore designed based on the following assumptions.

The renewable energy (RE) technologies in the scenarios are limited to commercially available technologies. Concentrating solar thermal (CST) power is restricted to established parabolic trough technology for which there is 30 years of operational experience with the Solar Electric Generating Station (SEGS) plants in California. It would be beneficial to include power towers if they can be assumed to be commercially available. Power towers have higher concentration ratios than parabolic troughs (over 1,000 for towers and less than 100 for troughs), use different heat transfer media that tolerate higher temperatures, operate at higher thermal efficiency, and have better winter performance due to optical tracking of the sun's elevation (Dunn et al. 2012). Some technologies such as hot dry rock geothermal power and wave power are being developed in 2014, but cannot yet be described as commercially available. The energy resource is significant (Geoscience Australia and ABARE 2010) and the production cost of electricity is not expected to be significantly higher than other technologies, principally due to high capacity factors (Bureau of Resources and Energy Economics 2012a). Behrens et al. (2012) identify significant wave power potential around the southern coastline of Australia with expected capacity factors of over 54%.

Conservative cost projections were used in the scenarios for the chosen technologies. Although technology cost data are collected and closely tracked in other parts of the world, mainly Europe (International Renewable Energy Agency 2012c) and the United States, data for Australia have only recently become available. Preference was given to cost data specific to Australia, where costs can differ quite markedly from other countries. For example, residential solar photovoltaic (PV) capital costs are currently lower in Australia than the United States, but utility-scale wind power costs are higher. Preference was also given to cost data that are derived by independent agencies and not industry bodies, which may be optimistic in their forecasts. The scenarios use cost projections from the Australian Energy Technology Assessment (AETA). These data are described in detail in Section 6.1.1.

Electricity demand was taken from the National Electricity Market (NEM) in a recent year. The choice of year is discussed in Section 4.1.2. Energy efficiency is often suggested as a low cost means of integrating higher levels of RE into electricity grids – so called 'powering down' (Kemp and Wexler 2010; Allen et al. 2013). It was felt that it would be more instructive to investigate how 100% renewable electricity could meet *unmodified* demand in a recent year. At the outset of this research, the expectation was that demand would continue to grow in future years and that using 2010 as the chosen year might be too optimistic. Annual demand has instead declined and, as of July 2013 has returned to 2005 levels (Pitt and Sherry 2013b). This decline can be attributed to consumer response to higher electricity prices, energy efficiency schemes, and the deployment of solar PV on residential rooftops (Pears 2013). It is now less certain that electricity demand in 2030 will necessarily be significantly higher than the current level.

The model uses realistic simulated generators that estimate electricity output using true weather observations at hourly resolution in the simulated year. This is important, as the weather conditions experienced in the simulated year influence generator output and are a determinant of demand, particularly heating and cooling loads.

Two valuable RE sources are somewhat contentious in Australia: hydroelectricity and electricity derived from bioenergy. Damming for hydroelectric power generation has been, and remains, opposed by conservationists due to its environmental impact. The use of bioenergy for electricity generation is contentious in Australia. There is a recognition that bioenergy must be used carefully in future energy systems utilising a high fraction of RE (Mathiesen et al. 2012). Public concerns arise from the belief that Australia has limited water for food production, that farms should be used for food production and not bioenergy crops, and previous publicity about electricity generation using waste timber from native forests. Therefore, the electricity generation from these two sources is kept to low levels – perhaps below what is economic and ecologically sustainable.

4.1.2 Choice of simulation year

The model simulates and evaluates the cost in present-day dollars of a generation system for the NEM in the year 2030 to reliably meet a 2010 NEM load profile. The year 2010 was selected for the following reasons:

- all of these data sets must be chosen for a consistent year. Weather influences renewable electricity generation, and weather influences electricity demand;
- in the year this research was started (2010), installed wind capacity in the NEM was at its highest level. Earlier years of data suffered from having less installed wind generation, as the expanded Renewable Energy Target (eRET) in Australia has led to a significant expansion of wind power. Using real wind farm output was more desirable than modelling generation by fitting synthetic wind speed data, such as that computed by the CSIRO Cubic Conformal Atmospheric Model (CCAM), to a wind turbine transfer function;

- Bureau of Meteorology (Bureau) satellite-derived solar radiation data and weather data from automatic weather stations were available with a satisfactory level of data quality. In earlier years, significant problems of data quality were present, particularly with the solar radiation data; and
- complete Australian Energy Market Operator (AEMO) demand data for 2010 were available.

The economic modelling presented in Chapters 6 and 7 requires the choice of a target year, as this determines the projected costs of RE technologies in that year. The year 2030 was chosen as a reasonable choice in the medium term, and technology cost projections for 2030 are available (Bureau of Resources and Energy Economics 2012a). Many 100% RE scenarios use 2050 as a target year, which coincides with the scientific consensus that it will be necessary to virtually eliminate greenhouse gas emissions by the middle of the century. However, using the year 2050 suffers the drawback that projecting costs and forecasting the development of different technologies over such a long time frame is more difficult and more likely to deviate from the prediction. In its Zero Carbon Australia Stationary Energy Plan, Wright and Hearps (2010) suggested that the stationary energy sector could be transformed by 2020. This choice, it was felt, is unrealistic and 2030 was chosen. It is straightforward to modify the model to test 2030 and 2050 cost data, or cost data from sources other than the Bureau of Resources and Energy Economics (2012a).

4.1.3 Open source license

The software for the model is freely distributed under the GNU General Public License (Free Software Foundation 2014) so that other researchers can use, modify, or validate the model. The software is now available on the Internet and is already being used by a research group at the University of Jaén in Spain. Open source modelling tools for energy system research in Australia are considered valuable for public research and is the subject of a government funded research project between the University of New South Wales and the University of Melbourne.

4.1.4 Extensible design

The model was developed incrementally so that model features were not developed until they were required. In software developed for research it can be difficult to anticipate what is required, so it is wasteful to expend effort developing features that are never used. By following this principle, the source code remained easy to understand and small enough to verify by inspection. Confidence was gained with the model with greater use, providing a foundation on which to build more complex model features.

Another objective of the model design was to keep it open to extension and easy modification. The model does not have a complex graphical user interface that predetermines the way the tool can be used. Users can write extensions to use the program in ways unanticipated by the author. As a simple example, a user can perform a sensitivity analysis by repeatedly varying the capacity of a single generator and inspecting the impact of this change on the results.

4.1.5 Stateless design

The model does not maintain any internal state variables. All state information for a simulation run is contained within a *context object*. Context objects are a technique drawn from object-oriented software design that groups a number of state variables into a single object or variable. This technique makes the design more robust because it reduces the possibility that old state information from a previous run can contaminate a subsequent run. All previous state information can be confidently discarded by destroying the context object. The use of context objects also enables exploration with the simulation tool. For example, two context objects can be created with different settings. After running the simulation twice, the results stored within each context object can be compared side-by-side.

4.1.6 Performance

A crucial requirement of the model is short running time. When the computational cost of running a single simulation is sufficiently low, it becomes feasible to employ simulation-based optimisation techniques to explore the problem space. With the high performance computer used for this work, eight parallel simulations can be completed every few seconds. This contrasts with other more detailed models such as the ReEDS/GridView combination employed by the National Renewable Energy Laboratory (NREL) in the Renewable Electricity Futures Study with a single run time of around 10 hours (Mai 2012).

By keeping the computational cost of a single simulation sufficiently low, it becomes feasible to employ simulation-based optimisation techniques to explore the problem space. The simulation framework is driven by a genetic algorithm (GA) to search for the lowest cost generating system. This is described in more detail in Section 4.7.

4.2 Computing environment

4.2.1 Hardware

The simulation software was developed and run on a high performance computer located at the National Computational Infrastructure (NCI) National Facility at the Australian National University. Other research projects at the NCI National Facility share the same physical hardware, but are completely isolated within virtual machines. This computer is suited to data intensive projects with fast disk performance and a large amount of memory. The computer is now less advanced than it was at the start of this research in 2010. A higher specification machine would be used if this work was started again today. The machine specifications are:

- Eight 2.27 GHz Intel Xeon CPUs;
- 48 GB of memory;
- 1 TB of network attached storage; and
- running the GNU/Linux operating system.

4.2.2 Programming environment

The Python programming language (version 2.6) was chosen to code the model. Python has a strong following in the scientific community and was selected because of the author's prior experience with it. Python is an interpreted language with a rich set of standard libraries and useful data types, which supports rapid prototyping of software. One advantage of an interpreted language such as Python, as opposed to a traditional compiled language, is that the program can be experimentally modified by users while the program is running. Python is free software, so others wishing to use the model can do so without requiring proprietary and potentially expensive software packages. A wide range of free, add-on libraries are available to add facilities such as scientific computing tools. These are often written in *C* so do not have the performance overhead of libraries that are strictly interpreted. Four third-party libraries were installed:

Matplotlib – adds 2-dimensional plotting;

Numpy – adds fast N-dimensional arrays and linear algebra routines;

Pyevolve – toolkit for evolutionary computing (genetic algorithms); and

PyTables – adds support for very large data tables.

These libraries provide the capability for handling and visualising large solar radiation and weather data sets. The PyTables package is important for work involving very large data sets. Usually array sizes are limited by the amount of virtual memory in a computer. PyTables overcomes this limitation by allowing very large tables to be stored on disk and accessed in segments as array elements are referenced. PyTables also allows tables to be compressed on disk, reducing disk space requirements by about 90% due to the compressible nature of often repetitive array data. Matplotlib is used to produce the hourly balancing plots such as in Figure 4.1. These plots can be either viewed interactively, with facilities for panning and zooming, or written to disk in common image formats.

Source code for the model was kept in version control using the Git version control system. The repository is now publicly available on the Internet at git://git.ozlabs.org/nemo.git.

4.3 Simulation framework

The simulation tool has three components: a framework that supervises the simulation and is independent of the energy system of interest, a large integrated database of historical meteorology and electricity industry data, and a library of simulated power generators. The library only contains the generator types of interest for the present research, but new types can be easily added or extended from existing types. A verification suite is included to demonstrate that the model functions correctly.

The simulations are deterministic and assume ideal generator and transmission network availability. Unlike the NEM, where Minimum Reserve Levels (MRLs) are routinely calculated for each region to ensure that the NEM reliability standard (0.002% unserved energy) is maintained, no spinning or non-spinning reserve capacity is modelled. Sub-hourly generation fluctuations are also not captured by the model. The model does not consider minimum operating levels, minimum start-up/shutdown times and ramp rates.

A review of 37 energy modelling software tools available in 2009 classified the tools by their capabilities, geographical scope, energy sectors included, timeframe and time step (Connolly et al. 2010). Using the terminology of the review, the model presented here can be approximately described as a simulation tool, a bottom-up tool, an operational optimisation, and an investment optimisation. It is similar to tools such as SimREN and EnergyPLAN, discussed in Chapter 3, that have been used to model national scenarios based on 100% renewable electricity overseas.

Each scenario specifies a generator list that determines the type and location of generators and the dispatch order. For each hour of the year, every generator in the merit order is invoked to handle some portion of the load for that hour.

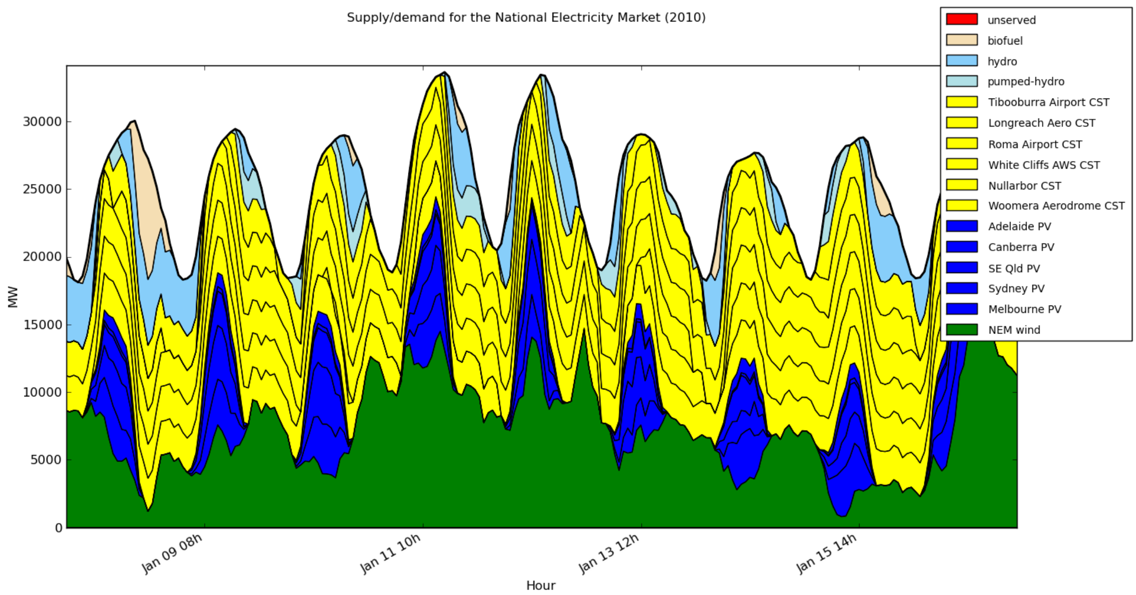

Figure 4.1: Sample supply and demand plot for the simulated NEM

For the weather-driven technologies, the simulated generators use meteorological observations from 2010 to estimate electrical output at a given location for each hour over the year. Each generator is given an opportunity to dispatch, even if it is not required. This gives all generators an opportunity to evaluate the state of the system in each simulation step and respond in some way, such as updating internal state variables.

In general, dispatch proceeds from the lowest operating cost plants without energy storage (PV and wind) before the dispatch of flexible plant with energy storage (CST, hydro, and gas turbines). If supply cannot meet the demand, the shortfall is recorded and the hour is marked as *unmet*. Conversely, if available supply exceeds demand, which can occur with high levels of lower capacity factor and zero fuel cost generation such as PV and wind, the simulation attempts to find another generator in the system that can store the excess power such as a pumped storage hydro (PSH) station. Any remaining power is then regarded as surplus.

At the end of a simulation run, the model produces a report and an hourly plot for the year showing the demand and the dispatched generation (Figure 4.1 shows an example). Any hours of unmet demand are indicated on the plot. The report includes the annual generation, CO_2 captured where applicable, and CO_2

emissions where applicable, of each generator. The report also summarises total energy surplus to demand, the number of hours of unmet demand and the total unserved energy for the year as a percentage of demand.

In the early simulations, the entire NEM geographic region is treated as a 'copper-plate': that is, power can flow unconstrained from any generation site to any load site. Hence, demand across all NEM regions is aggregated, as is supply. This assumption is partially removed in Chapter 6 to assess the transmission requirements between NEM regions.

4.4 Simulated generators

The simulation currently has the following classes of generators:

- on-shore wind power
- PV
- CST
- conventional hydropower
- pumped storage hydro
- open cycle gas turbines (OCGTs) fuelled by bioenergy or fossil gas
- coal with carbon capture and storage (CCS)
- combined cycle gas turbine (CCGT)
- CCGT with CCS

The hierarchy of generators is shown in Figure 4.3. Using object-oriented programming techniques, a new generator may be derived from an existing class of generator. All generators derive from the base Generator class which defines the behaviour common to all generators. Each generator may provide definitions for the following functions:

```
TAS wind (TAS1), 6.0 GW
  supplied 14.9 TWh, spilled 2.2 TWh, capcost $940.8M, opcost $209.9M
```

Figure 4.2: Example of generator summary output

step – every generator must define a step function that returns the energy generated for the hour and the amount of energy that is surplus (eg, for wind and PV). This function is invoked for every generator at each simulation step, even if generators low in the merit order are not required to meet the demand.

store – generators capable of storage (eg, pumped storage hydro) may optionally define this function to simulate the storage of surplus energy. If the generator is capable of storage, it must also set the object variable `storage_p` to `True`.

capcost – returns the annualised capital cost of the generator at its configured capacity. The base generator type defines this to be the capital cost, in $/kW/year, multiplied by the generator capacity.

opcost – returns the operating and maintenance costs of the generator at the end of the simulation run. The base generator type defines this to be operating and maintenance (O&M) costs, in $/MWh, multiplied by the total energy generated over the year.

summary – returns a summary string at the end of the simulation run including the amount of energy delivered, surplus energy, CO_2 captured where applicable, CO_2 emissions where applicable and the costs. This is used when producing the report at the end of the simulation run. An example summary for a single generator is shown in Figure 4.2.

set_capacity – change the generating capacity.

reset – reset the internal state of the generator for another simulation run.

One or more generator objects may be created from a generator class. For example, all PV generation may be represented in the system by a single PV generator object, or by multiple generator objects grouping sites or regions.

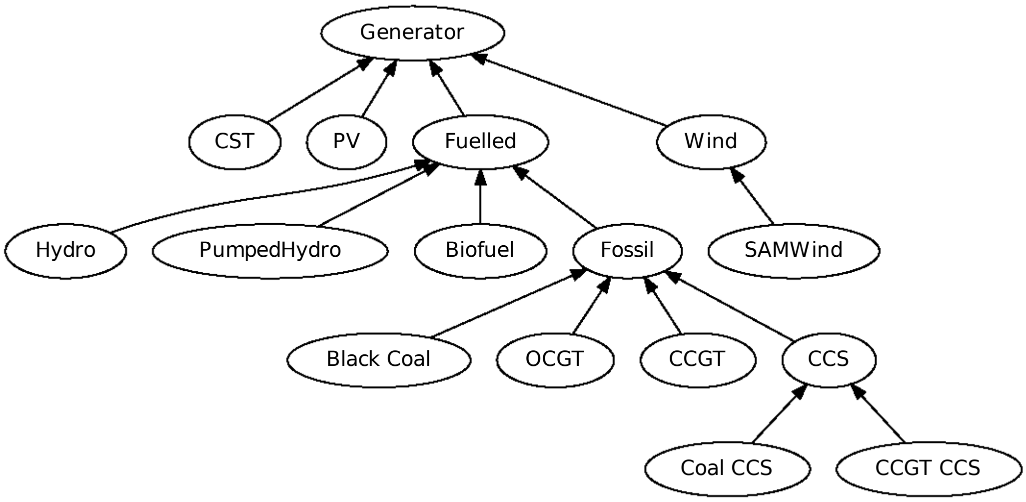

Figure 4.3: Generator class hierarchy

4.4.1 Wind power

The wind power model uses aggregated wind farm generation data from the NEM in 2010 and scales it on a proportional basis to the desired capacity. In 2010, there was approximately 1555 MW of wind power installed in the NEM. The placement of wind farms is unmodified and therefore there is no change in the shape of the wind power time series. The wind power model curtails any additional power that is surplus to demand. Off-shore wind was not considered. Australia is a sparsely populated country with ample land area for on-shore wind, unlike countries such as Denmark and Germany where off-shore wind is now being deployed. The east coast of Australia quickly goes to great depths making off-shore wind an expensive option. Messali and Diesendorf (2009) performed a search for promising off-shore wind sites and found that the best sites were off the coast of Western Australia, far from the NEM.

4.4.2 Photovoltaics

The PV model utilises detailed PV generation traces produced once, off-line using the System Advisor Model (SAM) PVWatts model with weather data for chosen locations in 2010. SAM is a software package produced by NREL that performs technical and financial performance modelling of numerous renewable energy technologies. SAM can model PV, CST, utility-scale wind power, geothermal power, and other technologies at hourly resolution using synthetic or observed renewable resource data. In the simulations, PV is distributed within the built environment of the major mainland cities of the NEM: Adelaide, the greater Brisbane region, Canberra, Melbourne and Sydney. The hourly power generation was modelled for a 1 MW PV system sited in each city, facing due north and tilted at the latitude angle. The generation of the 1 MW plant is then scaled to the desired capacity for each city. Note that this will underestimate the potential diversity value of large PV plants located in regional areas of the NEM to the west of the major load centres. In future scenarios, this could extend to utility-scale centralised plants sited in regional areas or multiple sets of generation data for a single city with different azimuth orientations. PV generators discard any additional energy that is surplus to demand.

4.4.3 Concentrating solar thermal electricity

Modelling the performance of CST power plants in specific high insolation locations was initially carried out using SAM and actual meteorological year data files generated for those locations in 2010 using a utility described in Section 4.8. The benefit of using SAM for CST modelling is that it uses a highly detailed physical model and incorporates meteorological variables that affect CST performance such as ambient temperature, wind speed and relative humidity. The disadvantage of this approach is that the SAM performance model operates outside of the simulation framework and cannot be sensitive to partial or non-existent demand. In a given hour, the load may be mostly met using generators higher in the merit order, leaving a small residual demand to be met by a single CST generator. Therefore, the CST generator is only required to operate at part-load, and additional CST plants further down the merit order are not required in that hour. When a simulated CST plant is not required for dispatching in a given hour, the simulation can divert solar thermal energy to storage for conversion later in the day. If the thermal storage is fully charged, additional power from the collector field is dumped, limiting the extent to which plant can be operated in a non-generating mode during the day.

To overcome this problem, the CST generator model was rewritten to integrate into the simulation framework. This comes at the expense of the detailed physical model in SAM. The new model is based on SIMPLESYS, a solar thermal performance model using an instantaneous energy balance (Stine and Geyer 2002). A reference implementation of SIMPLESYS is freely available in the JavaScript language. With permission from Stine (2013), this JavaScript program was hand-translated to Python and verified by verifying that identical results were obtained from the two implementations given the same inputs.

The new CST model includes storage modelling and sources of heat loss at a high level (see Figure 4.4). This level of detail in the model was deemed to be sufficient for this purpose. To retain as much of the detailed SAM physical model as possible, SAM was used to produce hourly traces of thermal power from the collector field at the chosen sites. These hourly traces are used as an input to the new CST model. Figure 4.5 shows the six operating modes of the CST model over the course of a clear day:

(1) collecting heat from the collector field to heat up the system before starting;

(2) collecting heat from the collector field to generate electricity;

(3) diverting heat above the demand level into storage;

(4) dumping some heat when the storage is full;

(5) collecting heat to generate electricity as in mode 2; and

(6) serving demand from thermal storage with no heat from the collector field.

In the original SIMPLESYS model, thermal power demand (QL in Figure 4.4) is constant. Whenever demand cannot be met by the collector field and/or thermal storage, power is supplied from an auxiliary source (QA). In the new CST model, demand may vary hour-to-hour. There is no auxiliary power source, so QA can instead be treated as unmet load. The thermal to electrical conversion efficiency of the CST plant is assumed to be 0.4.

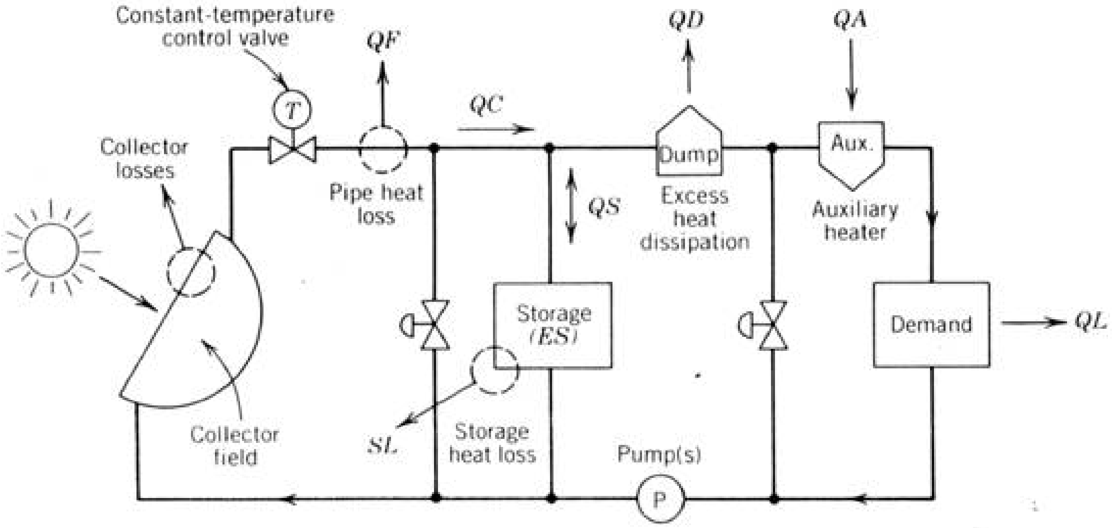

Figure 4.4: Schematic of the solar power system modelled by SIMPLESYS. Source: Stine and Geyer (2002)

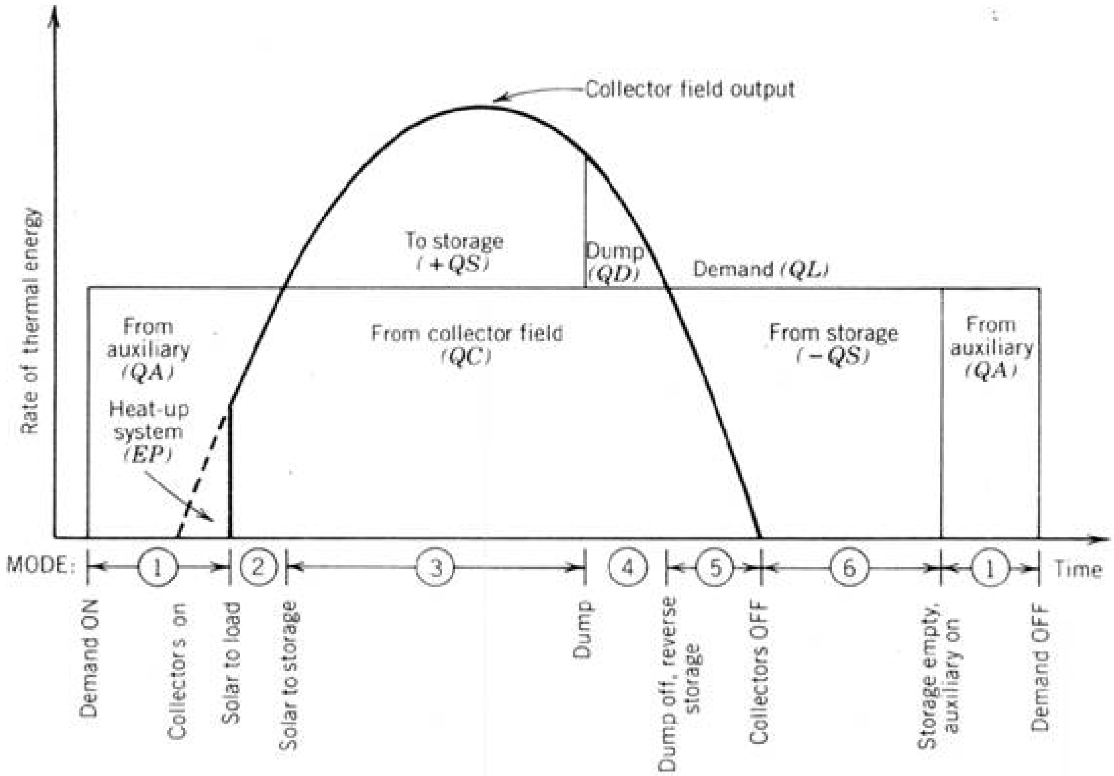

Figure 4.5: States of operation of the SIMPLESYS model. Source: Stine and Geyer (2002)

4.4.4 Hydroelectric stations

The hydroelectric generator model is a simple representation of a conventional dammed hydroelectric station that can always generate up to the rated capacity. The model does not simulate inflows or outflows from the reservoir (eg, rainfall, snow melt, evaporation, environmental flows). While dam levels will vary throughout the year, the model assumes that sufficient water is always available for generation. Resource limits for hydroelectric generation are instead imposed through the use of constraints. These are discussed further in Section 4.7.2.

4.4.5 Pumped storage hydroelectric stations

The pumped storage hydroelectric generator model simulates a PSH station with a single pump-turbine that can be operated as a pump or a turbine. The model represents a single pipeline linking the upper and lower reservoirs, such that the plant can only be pumping or generating in any given hour, but a change of mode can occur from one hour to the next. Half of the water volume is placed in the upper reservoir as an initial condition. When a PSH generator is defined in the simulations, the generating capacity and storage capacity must be specified. The model uses a default round-trip efficiency of 0.8, although this can also be specified.

4.4.6 Fuelled generators

The OCGT, CCGT, CCGT with CCS and coal with CCS models are all based on the same common code for dispatchable generators that consume fuel (see Figure 4.3) and so are described collectively here. The models assume that sufficient fuel is always available for generation. Resource limits for biofuelled OCGT generation, in particular, are imposed through the use of constraints, as for hydroelectricity. Generators that consume fossil fuel have an associated CO_2 emissions rate. A subset of these are equipped with post-combustion CCS and have a specified rate of emissions capture of 0.85.

```
/ (RootGroup) 'Integrated NEM modelling database'
/dni (CArray(113952, 679, 839), shuffle, blosc(6)) ''
/ghi (CArray(113952, 679, 839), shuffle, blosc(6)) ''
/aux (Group) ''
/aux/weather (Table(4445597,), 'BoM weather observations'
/aux/wstations (Table(515,), 'BoM weather stations'
/aux/aemo2010 (Group) ''
/aux/aemo2010/demand (Array(5, 17520)) 'NEM 2010 demand'
/aux/aemo2010/nonsched (Table(2618779,), 'NEM 2010 non-scheduled'
/aux/aemo2010/rrp (Array(5, 17520)) 'NEM 2010 regional ref. prices'
/aux/aemo2010/wind (Array(8760,)) 'NEM 2010 wind generation'
```

Figure 4.6: HDF5 database object tree showing the database contents and layout. CArray is the Pytables term for compressed arrays.

4.5 Model database and data sources

The integrated database incorporates a number of data sources. The data are maintained in separate tables in a single self-contained database. The database is in Hierarchical Data Format version 5 (HDF5) format, allowing different types of data to be separated using a naming structure similar to regular disk directories (see Figure 4.6). Each data set is now described in turn.

4.5.1 Electricity demand

In 2010, total electricity demand in the NEM was 204.4 TWh. Electricity demand data for the NEM in 2010 were obtained from the AEMO. Demand in the NEM is reported in each market region at 30 minute intervals. Due to the way that NEM data are reported, the demand data include the auxiliary loads of power stations to run conveyors, pumps, fans, and other equipment. These loads vary widely by generation technology. For example, auxiliary loads are negligible for wind farms, about 1% for hydroelectric stations, 7–8% for black coal stations, and 9–10% for brown coal stations (AEMO 2012b). The demand data therefore include a small, but not insignificant, contribution from loads that would not exist in a 100% RE system.

As the simulations are performed with hourly time steps, half-hourly demand is averaged into hourly values. Electricity demand is stored in the database on a regional basis. In some scenarios, demand is aggregated. In others, where regional demands are of interest, it is not.

4.5.2 Wind generation

Electricity generation data reported by wind farms over 30 MW rated capacity and operating in the NEM in 2010 were obtained from AEMO. These data supply average wind power at each wind farm over the five-minute dispatch interval and were averaged into hourly values.

4.5.3 Solar irradiance data

To realistically model the performance of solar PV and CST systems in chosen locations around Australia, solar radiation data of high coverage and good quality are required for the simulation year. The National Climate Centre at the Bureau produces two grid-based irradiance products, one for global horizontal irradiance (GHI) and one for direct normal irradiance (DNI). The estimates of GHI are made using satellite images collected from three satellites over the past 13 years: GMS-5 (Japan Meteorological Agency), GOES-9 (U.S. National Oceanic and Atmospheric Administration), and MTSAT-1R (Japan Meteorological Agency). A physical model progressively developed by Weymouth and Le Marshall (1999, 2001) is in operational use at the Bureau based on earlier work by Gautier et al. (1980) and Diak and Gautier (1983).

The Bureau now relies on satellite images produced by the MTSAT-2 (or Himawari-7) satellite operated by the Japanese Meteorological Agency (see Figure 4.7). MTSAT-2 is positioned at 145° longitude over Japan and Australia and these two countries are the principal users of the images it produces. MTSAT-2 produces images every hour over the southern hemisphere. The Japan Meteorological Agency (JMA) expects to launch two new, higher capability weather satellites named Himawari-8 and Himawari-9 in 2015 and 2016, respectively. The new satellites will be able to perform a full observation of the earth's disc in 10 minutes giving much higher temporal resolution than is currently available. This high frequency data will enable sub-hourly modelling of solar electricity systems. One difficulty is that the new data will only be available from the commissioning date, so it will be some time before a long range data set is available.

Weymouth and Le Marshall (1999) presented the physical model in operational use at the Bureau, emphasising the operational requirements of a solar radiation service. Weymouth and Le Marshall (1999) gave two main benefits of space-based estimates over ground stations. First, the reliability of satellite images is much higher than a network of ground stations that require regular cleaning and calibration. Second, the cost of the service is lower, as the satellites are already put into service to provide data for weather forecasting. For a large and sparsely populated country like Australia, it is unrealistic to expect that a large network of pyranometers could be cost effectively operated. This makes a space-based service appealing.

Feedback adjustments to the model from a limited number of pyranometer readings are used to eliminate bias due to sensor calibration errors, biased estimates of water vapour from the numerical weather prediction model, and aerosol effects (Weymouth and Le Marshall 2001). These corrections are, on average, less than 1%. With these corrections applied, the satellite-derived data is comparable in uncertainty to good quality pyranometers. Weymouth and Le Marshall (2001) provided evidence that satellite derived observations are consistently accurate enough to undertake solar resource assessment studies using data currently available from the Bureau. Although it is clearly infeasible to establish a network of pyranometers across the continent at the required density, this work highlights the important role that a selected number of carefully sited pyranometers plays in eliminating bias from the model.

DNI is estimated from global horizontal irradiance using an adapted version of a diffuse fraction model by Ridley et al. (2010). The data set will be briefly described here, but full details are available in a meta-data document that accompanies the data sets (Bureau of Meteorology 2010b). The spatial extent of both data sets includes the entire Australian continent (10.05°S to 43.95°S, 112.05°E to

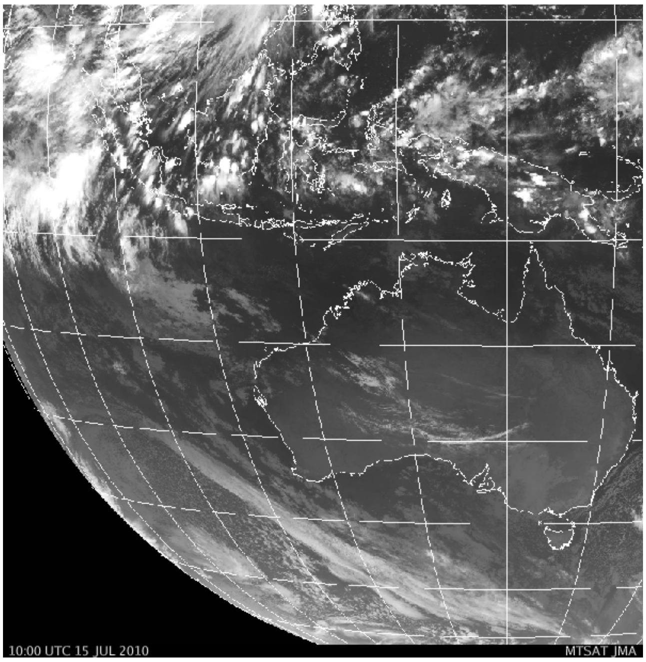

Figure 4.7: MTSAT infrared image of Australia at 0500 UTC, July 15, 2010. Source: Japan Meteorological Agency

153.95°E). The spatial resolution is approximately 5 km by 5 km. The temporal resolution of the data is one hour and the range is shown in Table 4.1. No data are available from July 1, 2001 to June 30, 2003 due to a long transition from the GMS-5 satellite imagery to GOES-9 imagery. Additional grids beyond December 2012 are being produced as images become available. The data includes up to 18 hourly grids per day. Hours 12 to 17 UTC are excluded for brevity, as these grids are dark on every day of the year. Additional grids may be missing due to absent or poor quality images. This data set represents the most comprehensive estimate DNI available for the Australian continent. Although data derived from high availability weather satellites should be much more reliable than a network of ground stations that require regular cleaning and calibration, the data set is missing numerous hourly grids. The data for the year 2010 are largely complete, however 22 hourly grids are missing and were filled in by interpolation. Around 1.7% of all hours in the 13 years of data is missing. A small number of anomalies in the data were detected by consistency checks included in the script that loads the data into the table. These problems were reported back to the Bureau.

The Bureau of Meteorology solar irradiance data are supplied as human-

Start date	End date	Satellite
1998-01-01	2001-06-30	GMS-5
2003-07-01	2005-10-31	GOES-9
2005-11-01	2010-12-31	MTSAT-1R

Table 4.1: Satellite sources used. Source: Bureau of Meteorology (2010a)

readable ASCII text files, one hourly grid per file. Within each file, the individual hourly irradiance observation (W/m^2) is presented in 679 lines of 839 columns of plain text. The data were loaded into a PyTables 3-dimensional array of dimensions 113,952 by 679 by 839. Unlike the original data set, the table does not have any missing grids. If an hourly grid is missing from the original data files when being loaded into the table, the table is populated with a grid of 'nodata' values. This makes it possible to traverse the entire table, hour by hour, without special handling of missing hourly grids.

4.5.4 Weather station data

Hourly weather records for every automatic weather station in the NEM region in 2010 were supplied by the Bureau. These records include relevant meteorological variables such as dry bulb temperature, wet bulb temperature, relative humidity, wind direction, wind speed and atmospheric pressure. These observations, combined with solar irradiance estimates, were used to generate weather data files for selected sites around the NEM in 2010. This process is described in more detail in Section 4.8. The files are generated in the EnergyPlus Weather (EPW) format suitable for use with SAM. SAM performance models normally use Typical Meteorological Year (TMY) data. However, it is possible to use the same file format to store an actual meteorological year, subject to limitations of the file format such as handling of leap years. SAM was used to model the hourly power generation of PV and CST systems in selected locations in 2010, allowing realistic generation data to be included in the simulation.

4.6 Transmission network model

In Chapter 6, the regional transmission requirements of 100% renewable electricity in the NEM are considered by partially removing the copper plate assumption. For this, the model was extended to consider electricity supply and demand on a regional basis. Each generator in the simulation is assigned to one of the five NEM regions, based on its geographic location (Table 6.1). Generators are selected to ensure wide geographic placement over the NEM regions, limited to the commercially available technologies described in Section 4.1, and subject to data availability.

Table 6.1 lists multiple generators of the same type. For example, hydroelectric generation is represented by three simulated generators in each of Tasmania, New South Wales (NSW) and Victoria. PV and CST generators are assigned to specific locations. CST generators are sited in locations with high annual solar insolation. PV generation is distributed within the built environment of the major mainland cities of the NEM: Adelaide, the greater Brisbane region, Canberra, Melbourne and Sydney.

Today, most adjacent NEM regions have a direct transmission connection, although some have low power capacity (Figure 2.3). Figure 4.8 shows a simplified network with the same regional interconnections as the NEM. For energy exchanges to occur between two distant, non-adjacent regions (eg, Queensland and Tasmania), energy must be transferred through one or more intermediate regions. Excluding the four cases in the opposite direction, the remaining six cases are: QLD/TAS, QLD/VIC, SA/TAS and TAS/NSW (Figure 4.8).

A 5×5 matrix $\mathbf{C}$ represents the regional connectivity between the regions. Currently, the framework only permits a single path between any two regions. There are three possible cases for each element $c_{i,j}$:

- an empty list in the diagonal entries, $c_{i,i} = \epsilon$;
- for regions that are directly connected, $c_{i,j} = (i, j)$; and
- for regions that are not directly connected, $c_{i,j}$ is a list of directly connected

Figure 4.8: Nodes in a simplified transmission network. Dashed lines indicate two additional interconnections for South Australia that are not presently in the transmission network. Map courtesy of Geoscience Australia.

	QLD	SA	TAS	VIC
NSW	1,100	1,100	1,100	600
QLD		1,200	2,200	1,600
SA			1,600	1,100
TAS				600

Table 4.2: Direct distance between NEM region centres (km)

region pairs forming a path from region i to region j.

The distance between each region is coarsely approximated using the geodetic centre of each state and territory (Geoscience Australia 2010) and is given in Table 4.2. This choice provides a reasonable compromise between the location of the major demand centres, typically near to the coastline, and the most promising locations for renewable generation, sometimes far inland. Although additional transmission infrastructure will be required to completely connect generators to demand centres, this simplified network assists in approximating the transmission requirements of different geographical and capacity configurations.

4.6.1 Regional dispatch algorithm

Originally generators were dispatched in a predetermined merit order using the following simple algorithm:

```
for each hour of the year
    for each generator in merit order
        dispatch power to meet residual aggregate demand
```

Any energy surplus to demand is either stored by storage-equipped generators (eg, pumped storage hydro), or is discarded. For modelling the system at a regional level, the dispatch algorithm is modified to dispatch power from each generator in merit order to regional loads around the NEM:

```
for each hour of the year
    for each generator in merit order
        dispatch power to meet residual regional demand
        (in proximity order)
```

Proximity order is defined as:

(i) the region where the generation being dispatched is sited;

(ii) a directly connected neighbouring region; and

(iii) a non-neighbouring region, with closer regions preferred over farther regions so as to minimise transmission losses.

Dispatching power in proximity order is not strictly necessary, as the optimisation is likely to arrive at the same result through minimisation of transmission costs. The dispatch algorithm was implemented in this way to assist the genetic algorithm with faster convergence. Using a simpler dispatch model and allowing the genetic algorithm to completely optimise for transmission costs without this guidance would be a useful future exercise. As before, surplus energy is either stored by storage-equipped generators or discarded. Storage sites are selected in order of proximity to the generating region.

It must be emphasised that the dispatch algorithm continues to meet demand in the fixed merit order, corresponding to increasing marginal cost. Within an individual simulation run, the simulation framework dispatches available plant in merit order, while the genetic algorithm operates in a supervisory role, changing the system configuration between individual runs. Electricity demand and supply are not balanced on a region-by-region basis before energy may be exchanged between regions. For example, a biofuelled gas turbine located in Tasmania is not necessarily used to serve residual Tasmanian demand if wind power, higher in the merit order, is available from nearby Victoria. It is assumed that it is preferable to meet demand using lower marginal cost, less controllable generation such as wind and solar PV from distant regions, even if this leads to larger energy exchanges between regions.

4.6.2 Energy exchanges

The simulation framework records energy exchanges each hour between every pair of regions. Capacity constraints are not imposed on the interconnections, so the transmission network is not modelled as would be traditionally done in a power system analysis. Instead, the simplified transmission network is used to gain a high level appreciation of the transmission network cost implications of different generation mixes and siting. This enables the cost of different system configurations to be better compared.

4.6.3 Cost model

A cost model is also added to the simulation framework. The cost model calculates the annual cost of the system by summing the annual cost of each generator in the simulated year. Each generator type is assigned an annualised capital cost in \$/kW/yr, fixed O&M in \$/kW/yr, and variable costs in \$/MWh. In the simulation framework, these costs are not limited to being constants. For example, in the future, a more sophisticated gas turbine model could calculate stepwise maintenance costs based on the number of running hours as the simulation advances. At the end of a simulation run, the framework calculates the total annual cost of each generator in the simulated year.

4.7 Genetic algorithm

In the simulations described in Chapter 5, the generating capacities of the various renewable plant are chosen by 'guided exploration' to ensure that low marginal cost generation such as wind and CST contribute a large share of generation, that bioenergy consumption is kept to low levels, and that the NEM reliability standard is met. In contrast, in Chapters 6 and 7, a genetic algorithm is used to vary the generating capacity of each generator in the system and ensure that various constraints are met.

A genetic algorithm (GA) is a search technique that emulates the evolutionary process of breeding and mutation over a number of generations to find the fittest individuals according to objective criteria. Goldberg (1989) is the definitive reference for readers who may be unfamiliar with these algorithms. Genetic algorithms are a powerful way of searching large, complex problem spaces by evaluating only a small number of the total possibilities. An appealing feature of genetic algorithms is that they encourage the user to specify a minimal number of constraints and not anticipate the possible solution space. Sometimes this can lead to unexpected and interesting results.

A wide range of meta-heuristic methods are available for search problems involving function minima. In addition to GAs, simulated annealing (Ekren and Ekren 2010) and particle swarm optimisation (PSO) are two other possible approaches. GA was chosen due to the author's experience with them. Knowing when a GA is performing acceptably comes with experience and it was felt that the choice of search algorithm is a means to an end in this research. Experience was therefore deemed more important than choosing an algorithm that may be marginally superior in other respects. The model presented here can employ many more parameters than exhaustive approaches such as by Budischak et al. (2013). For example, additional parameters could be introduced to represent the thermal storage capacity in CST plants instead of fixing the storage capacity at 15 full-load hours.

Hassan et al. (2005) tested the effectiveness (whether solutions are within 1% of the known optimum) and the number of objective function evaluations to converge on a solution by GAs and PSOs on eight benchmark problems. PSO was found to have comparable effectiveness as GA, but better performance than GAs on problems with continuous design variables, so is worthy of future investigation. The use of PSO is not expected to significantly alter the results, but could allow for larger problems to be attempted.

Pyevolve is a Python toolkit for genetic algorithms and is used for this work (Perone 2009). Pyevolve requires a programmer to supply only a suitable genetic representation for each individual and an evaluation function to score the fitness of each individual. The genetic representation and the evaluation function are described in the following sections.

4.7.1 Genetic representation

There are 25 generators in the scenarios (Table 6.1). The existing NEM hydroelectric stations, represented by five generators, have fixed generating capacities and are excluded from the genetic representation. Each individual is therefore encoded with 20 real values, each value representing the capacity of a generator as illustrated in Figure 4.9. It is possible for the GA to exclude a generator by setting its capacity to zero.

4.7.2 Evaluation function

The evaluation function calculates a projected annual cost of meeting 2010 demand in the NEM in 2030 in billions of dollars per year (2012 \$). Hence, the GA searches for the individual with the *lowest* fitness score. The evaluation function is defined as the sum of:

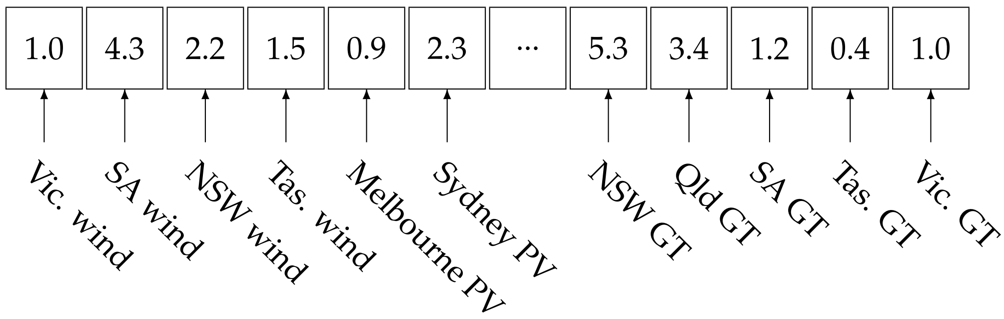

Figure 4.9: Genetic representation of a single generator system with contrived capacities (in GW) in each box.

- total annualised capital cost of generating capacity (excluding hydro);
- total fixed O&M costs for the year;
- total variable O&M costs for the year;
- penalty functions to enforce three constraints:
  - unserved energy shall not exceed 0.002% of annual demand D:

$$f(x) = \max(0, x - \frac{D}{50000})^3$$

  - generation from bioenergy shall not exceed 20×10^6 MWh (20 TWh):

$$g(x) = \max(0, x - 20 \times 10^6)^3$$

  - hydroelectric generation shall not exceed 12×10^6 MWh (12 TWh):

$$h(x) = \max(0, x - 12 \times 10^6)^3$$

- optionally, the estimated cost of transmission.

The evaluation function does not include the economic costs of unmet demand. With the exception of fossil fuel scenarios considered in Chapter 7, where carbon pricing is factored into the operating costs of a generator, no other externality costs are included in the evaluation function (eg, air pollution associated with the combustion of bioenergy).

Population size	100
Generations	100
Mutation rate	0.2
Cross-over rate	0.9
Selection algorithm	Rank selection

Table 4.3: Genetic algorithm operating parameters

Each of the three penalty functions are raised to its cube to guide the GA strongly towards each target value. The drawback of approaches such as using a step function with a single large value denoting a constraint violation is that it provides the GA with no indication about the degree to which an individual violates the constraint (Zalzala and Fleming 1997). An appropriate power function was found to be effective in leading the GA to converge on the target value.

The evaluation function may optionally include an estimate of the transmission network costs between the various NEM regions. As described in Section 4.6.2, the framework records the energy exchanges between regions as dispatching occurs each hour. The transmission cost t is calculated as the sum of transmission costs between every pair of regions:

$$t = \sum_{i=1}^{5} \sum_{j=1}^{5} e_{i,j} \cdot d_{i,j} \cdot c$$

where $e_{i,j}$ is the peak energy exchange encountered during the year, $d_{i,j}$ is the distance between region i and region j (Table 4.2), and c is the annualised unit cost of transmission in \$/MW-km/yr. The capital cost of high voltage direct current (HVDC) transmission has been conservatively estimated at \$800/MW-km (Bahrman and Johnson 2007). The capital cost of HVDC end stations is not included. The annualised cost of transmission was calculated using a lifetime of 50 years.

A large number of simulations are run as the parameter space is explored. After some experimentation to ensure that the parameter space was being adequately explored, the GA operating parameters in Table 4.3 were chosen. Individuals are propagated to the next generation by the rank selection algorithm with elitism, which ensures that the fittest individual in each generation is always propagated.

4.8 Generating historical weather data files

The Bureau of Meteorology (Bureau) is the authoritative source of weather and climate data in Australia. The Bureau provides these data to the public in simple, text-based formats. In recent years, the availability of modelling software that utilises weather and climate data has expanded considerably. These include thermal energy simulation packages such as TRNSYS, home energy rating tools such as FirstRate and, more recently, RE simulation packages such as SAM. This section describes a software utility that generates weather data files in file formats compatible with these packages from historical Bureau climate data.

Until recently, the aforementioned software packages have used weather data files representing a Typical Meteorological Year (TMY). Data for Australia is limited to some 70 locations (US Department of Energy 2014a). TMY is a synthetic time series with data for each of the 12 months of the year carefully chosen from a long historical record. This provides a reasonable indication of the long term average while maintaining the variability in the local climate. While this has merit for predicting the long-term technical and financial performance of a RE system, TMY data have limited application in matching time-varying solar generation to other weather dependent time series such as electricity demand or spot market prices.

Companies are emerging that sell weather data products over the Internet. Clean Power Research operates a web site called Solar Anywhere[2]. This company is progressively developing United States (US) solar radiation data at higher temporal resolution by interpolating between hourly solar irradiance values based on cloud motion. Weather Analytics[3] offers generated data files for any world-wide location, but at a coarse spatial resolution of 35 km by 35 km.

SAM is becoming increasingly popular for solar research in Australia. Maze and Miller (2010) used SAM to evaluate the performance of a CST plant with identical characteristics to the Spanish Andasol-I plant operating in 29 Australian locations. Johnston (2009) used SAM to evaluate the financial performance of a

[2]http://solaranywhere.com
[3]http://weatheranalytics.com

250 MW CST plant participating in the NEM using TMY data and NEM spot price data to estimate plant output and revenue excluding any subsidies. An Australian companion guide to SAM has recently been produced (Lovegrove et al. 2013).

4.8.1 Weather data file formats

A number of weather data file formats are used by the software packages mentioned above. To date, there has been no effort to standardise on a universal format, but a number of de facto standard file formats have emerged as it becomes clear that weather data interchange is desirable. The main formats are TMY, TMY2 (version 2), TMY3 (version 3) and EPW. EPW and TMY3 will be briefly described below. Although the TMY family of formats share their name with TMY data, the formats are capable of storing actual meteorological year data. The use of TMY3 over TMY and TMY2 is recommended because TMY3 is more readable and does not have the limitation of using fixed column numbers to delimit fields (Wilcox and Marion 2008). Therefore, the older formats will not be discussed further.

The EPW file format is used by the EnergyPlus building simulation package developed for the US Department of Energy. The format is human readable using comma-separated values and is well documented. The file consists of a number of header rows including location details and some meta data. The remainder of the file contains records of hourly values for a range of meteorological variables including wind speed, wind direction, global horizontal irradiation (over one hour) and direct normal irradiation (over one hour). The EPW format defines special values for missing data elements (eg, 9999).

The TMY3 file format is also a text-based format using comma separated values. It has a simple two line header followed by 8,760 hourly records. Unlike EPW, TMY3 cannot represent a leap year; the implications of this will be discussed later. The TMY3 hourly records have 68 fields each, representing many more meteorological variables than EPW. As with EPW, the TMY3 reference documentation describes special values that may be used for missing data elements (Wilcox and Marion 2008).

4.8.2 Australian weather data sources

Hourly observations to complete the weather data file may be obtained from Bureau climate archives, subject to record keeping and the availability of a Bureau weather station at the desired location. Weather station details such as the latitude, longitude and elevation of the station site can be found in the supplied 'station details' file. It is not possible at present to obtain hourly climate data from the Bureau web site. For hourly records, it is necessary to submit a special request and a fee is charged to cover the cost of extracting the data.

Accurate solar radiation data from the nine Bureau stations equipped to measure surface solar radiation could be used to generate weather data files in these locations. However, for this work, the Bureau satellite-derived solar irradiance database is used exclusively. For a location and year of interest, a 5 km by 5 km cell is selected and hourly values of GHI and direct normal irradiance are extracted.

4.8.3 Weather data file utility

The utility that has been developed is a Python program that will run on any computer with the Python interpreter installed. The utility has no graphical user interface. It is operated from the command line.

The utility reads a Bureau-supplied weather data file, an accompanying station details file, and a surface solar irradiance database for a given year and generates a weather data file in the chosen format: TMY3 or EPW. The initial purpose of this utility was to produce weather data files solely for use with SAM, so only the minimum number of fields are completed in the generated file. Table 4.4 lists the fields required by the SAM solar plant models, irrespective of the weather file format used (Gilman 2011). All other fields can be omitted if data are not available.

A limitation of this approach to creating weather data for actual years is that the TMY3 file format limits the number of hourly records to 8,760 and so is unable to represent a leap year. The EPW file format does allow for leap years to be represented through the 'Holidays/Daylight Saving' header record. At

Dry bulb temperature	Wind velocity	Site latitude
Dew point temperature	Wind direction	Site longitude
Wet bulb temperature	Atmospheric pressure	Site elevation
Relative humidity	Global horizontal irradiation	
Hour of the day	Direct normal irradiation	

Table 4.4: Data fields used by SAM solar plant models

present, the utility does not observe leap years, so February 29 is omitted from any generated file in a leap year. This limitation does not present any problems for the chosen simulated year (2010).

4.8.4 Summary

It can be valuable for solar researchers and practitioners to retrospectively evaluate solar power system performance using actual meteorological data. Where Bureau weather station data are available, systems can be modelled in any Australian location and for any year. This enables plant performance to be analysed in a wide range of operating conditions. Periods of uncommon, but extreme conditions such as dust storms, cyclones, heat waves or high wind conditions are of particular interest in grid integration studies. In addition, when other coincident weather dependent time series are available, such as electricity price or electricity demand, valid comparisons can be made between these time series.

The development of web sites such as Solar Anywhere and Weather Analytics suggests that there is some interest in a commercial service that provides weather data files for chosen times and locations in commonly used file formats. A similar service to provide Australian weather data files over the web using high quality meteorological data could, in principle, be provided by an authoritative source such as the Bureau.

4.8.5 Future enhancements

The utility was developed in support of simulating PV and CST generators in this thesis. It is far from a finished product, and there are several directions where this utility and associated work could be taken:

- quantify the error introduced by using several weather data sources which are not synchronised to a time reference for hourly observations. The satellite images used for deriving surface irradiance are not synchronised with the ground weather station observations. They are typically taken 46 to 52 minutes past each hour and vary with latitude;

- the utility could be enhanced in the future to correctly handle leap years when the EPW format is chosen, and to warn the user when generating a TMY3 file;

- incorporate more variables than the minimum set required by SAM. This would allow the weather data files to be used with other packages; and

- compare the simulated historical performance of photovoltaic plants located at a test bed facility, such as the Desert Knowledge Australia Solar Centre in Alice Springs, with recorded power production.

4.9 Chapter summary

This chapter has provided a detailed description of the design and construction of a model for simulating 100% renewable electricity systems. In the succeeding chapters, the model is used to simulate numerous scenarios with high penetrations of renewable electricity in the NEM. These scenarios evaluate operational feasibility of 100% renewable electricity (Chapter 5), the least cost 100% renewable electricity scenarios in the NEM (Chapter 6), and a comparison with other low- and medium-carbon electricity scenarios based on fossil fuel (Chapter 7).

Chapter 5

Operational feasibility

5.1 Introduction

This chapter reports on the use of the model presented in Chapter 4 to simulate a scenario of 100% renewable electricity in the region spanned by the National Electricity Market (NEM) for the year 2010, using actual demand data and weather observations for that year. This provides a straightforward basis for exploring the question of reliably matching variable renewable energy (RE) sources to demand.

In the simulations, electricity demand is met by a generation mix based on current commercially available technology: wind power, parabolic trough concentrating solar thermal (CST) with thermal storage, photovoltaics (PV), existing hydroelectric power stations, and gas turbines fired with biofuels. There is no fossil fuel generation in this mix, a marked contrast from the present NEM generation portfolio. By minimising the number of working assumptions, the aim is to provide some insights into the potential contribution from different renewable sources and the reliability implications of 100% renewable electricity for the NEM.

The NEM reliability standard is currently set at 0.002% of unserved energy per year (Australian Energy Regulator 2011). This standard recognises that ensuring sufficient generating capacity to meet any plausible demand in the system would impose a significant economic cost. Hence the NEM is not operated on the basis that all demand must be met every hour of the year. Instead, system balancing can be achieved through shedding controllable loads such as aluminium smelters or very limited load shedding in specific areas over a year. The total power demand of the six aluminium smelters situated within the NEM has been estimated at over 3 GW (Turton 2002). A number of these smelters actively participate in the NEM as potential demand-side response.

The rest of this chapter is structured as follows. Section 5.2 initially describes the main baseline scenario. In Section 5.3, the results of simulating the baseline scenario with the modelling tool are given. In Section 5.4, a number of sensitivity analyses are performed using different mixes to examine their effect on the reliability and composition of the system. Section 5.5 discusses the results and implications.

5.2 Baseline generation mix

The following section presents a baseline generation mix for the scenario.

5.2.1 Hydroelectricity

Hydroelectric generation in the simulation corresponds to hydroelectric stations present in the NEM in 2010. This is limited to 4.9 GW of conventional hydro and 2.2 GW of pumped storage hydro (PSH). Although the potential for significant further expansion of hydroelectric energy generation is limited by a lack of water and environmental concerns (Geoscience Australia and ABARE 2010), there may be potential for substantially increasing pumped hydro generating capacity and hence peak load generation, even with low levels of energy storage (Blakers et al. 2010). Sustainable Energy Now (2013) has identified coastal cliffs in Western Australia suitable for 24 hours of energy storage. The ocean forms the lower reservoir and large ponds atop the cliff, 10 metres deep, form the upper reservoir. Such proposals require more detailed investigation. Pumped hydro energy storage is initially set at 20 GWh based on prior estimates (Lang 2010). Water availability for hydro without pumped storage is not limited initially.

In normal practice, a pumped storage hydro system is charged using off-peak power and dispatched during peak periods. In these simulations, pumped storage hydro plants are opportunistically charged using surplus renewable power with a round-trip efficiency of 0.8. It is dispatched conventionally to meet critical peak loads.

5.2.2 PV

In the initial simulations, which were not optimised economically, PV served about 10% of total energy demand at an assumed average capacity factor of 16%. The PV is distributed within the built environment of the major mainland cities of the NEM: Adelaide, the greater Brisbane region, Canberra, Melbourne and Sydney. In future scenarios, this could extend to larger, centralised plants sited in regional areas. The capacity installed in each city is chosen in proportion to the population of the city (Australian Bureau of Statistics 2010).

5.2.3 Wind

In the initial simulations, which were not optimised economically, wind energy served about 30% of total energy demand at an assumed average capacity factor of 30%, a conservative value for Australian wind farms. The wind farms are sited in the same locations as existing NEM wind farms, but the hourly generation is scaled up from the installed capacity of 1.55 GW in 2010. This will underestimate the diversity value of having future wind generation sited in other wind regimes, a subject examined in Chapter 8.

5.2.4 Concentrating solar thermal

In the initial simulations, which were not optimised economically, CST served about 40% of total energy at an assumed average capacity factor of 60%. The CST plants are air-cooled parabolic trough designs with 15 full load hours of thermal energy storage. The solar multiple is initially chosen to be 2.5. This means that the mirror field and receiver at peak output produce 2.5 times more energy than is required by the turbine at full output. The excess energy is fed into the storage for use when there is insufficient sunlight. The hourly power generation of a

100 MW-e plant was modelled in six high insolation, inland locations around the NEM (listed in Section 5.2.6). The hourly values are then scaled to the desired capacity for each location.

5.2.5 Gas turbines

Gas turbines are placed last in the merit order to meet supply shortfalls. In the scenario, the turbines are powered with biofuels derived from crop residues. Commercial gas turbines that can be flexibly powered with a variety of fuels are available with capacities up to around 350 MW. The amount of fuel consumed by the gas turbines is not limited in the simulation so that the effect of changes in generation mix on biofuel consumption can be observed. However, one objective is to minimise the use of biofuel.

Manufacturers of thermal generators are responding to the changing nature of the generation mix. Some manufacturers are now specifically marketing the flexibility of their open cycle and combined cycle gas turbines for inter-operation with wind generation. However, the requirement for more flexible operation may be at odds with the further requirement for improved heat rates to reduce fuel costs and emissions. Raising the thermodynamic efficiency of a steam plant requires a design that can withstand higher steam temperatures and pressures. These components may need to be constructed from materials that are less forgiving of stop-start operation (Boyle 2007, Chapter 6).

In countries where fossil fuel is not as abundant as Australia, bioenergy has a significant share of electricity generation: Germany 4%, Sweden 7%, and Finland 12% (Geoscience Australia and ABARE 2010). Although a small share of total electricity generation, the United States produces 70 TWh of electricity from bioenergy per year (Geoscience Australia and ABARE 2010). Previous studies have estimated that about 30% of Australia's current electricity demand could be met from biomass residues alone in a year that is not subject to drought (Diesendorf 2007b, 138–41). Aiming for biofuel consumption below around 15% of total NEM demand is therefore considered realistic.

5.2.6 Generation mix summary

The generators in the baseline scenario, including their location and capacity, are summarised in the list below. The generators are dispatched in this order:

(1) Wind: existing wind farm output scaled to 23.2 GW

(2) PV (14.6 GW total):

- Adelaide (1.3 GW)
- Canberra (0.4 GW)
- Melbourne (4.5 GW)
- Brisbane and greater area (3.3 GW)
- Sydney (5.1 GW)

(3) CST (2.6 GW per site, 15.6 GW total):

- Tibooburra, New South Wales
- White Cliffs, New South Wales
- Longreach, Queensland
- Roma, Queensland
- Nullarbor, South Australia
- Woomera, South Australia

(4) Pumped storage hydro (2.2 GW)

(5) Hydro without pumped storage (4.9 GW)

(6) Gas turbines, biofuelled (24.0 GW)

For comparison, Table 5.1 shows the real installed capacity and actual generation in the NEM in 2010 from the renewable sources used in these simulations. Hydroelectric generation for 2010 is estimated using the average of 2009-10 and 2010-11 figures.

Source	Capacity (MW)	Generation (TWh)
Solar PV	483	< 1
Wind	1555	4.4
Hydro	7100	14.8

Table 5.1: Real capacity and generation from solar PV, wind and hydro in 2010. Source: AEMO (2012c), Watt and Passey (2010)

Surplus energy (TWh)	10.2
Surplus hours	1606
Unserved energy	0.002%
Unmet hours	6
Electrical energy from gas turbines (TWh)	28.0
Largest supply shortfall (GW)	1.33

Table 5.2: NEM simulation 2010 summary report

5.3 Baseline simulation results

In 2010, energy demand in the NEM was 204.4 TWh and peak power demand was 33.6 GW. Figures 5.1 and 5.2 show more detailed sections of the plot for a typical week in January and a challenging week in late June/early July, respectively. The simulation summary report is shown in Table 5.2.

The baseline scenario meets 2010 demand within NEM reliability standards, with six hours on winter evenings when demand was unmet: 15 June 6–8pm, 1 July 6–8pm, 2 July 6–7pm, 7 July 7–8pm. Comparing Figures 5.1 and 5.2, it is apparent how the seasonal variation of solar radiation influences the ability of CST plants to dispatch power. In Figure 5.1 (summer), the plants can be dispatched around the clock. In Figure 5.2 (winter), the low level of winter insolation is insufficient to fully heat the thermal stores and so the CST plant cannot generate through the night. In summer, 15 hours of storage and a solar multiple of 2.5 are more than adequate for CST to supply continuous energy day and night. Analysis of CST modelling results within System Advisor Model (SAM) shows that such a large thermal store is of limited value during the winter months, as storage larger than 5 full load hours is rarely fully charged.

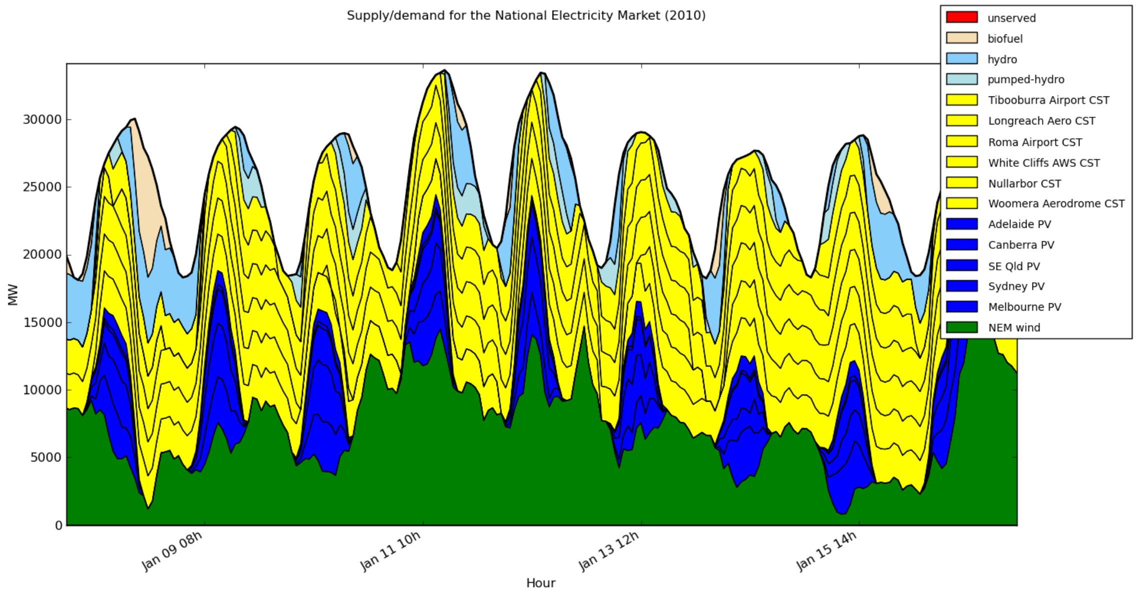

Figure 5.1: Supply and demand plot for the simulated NEM for a typical week in January 2010

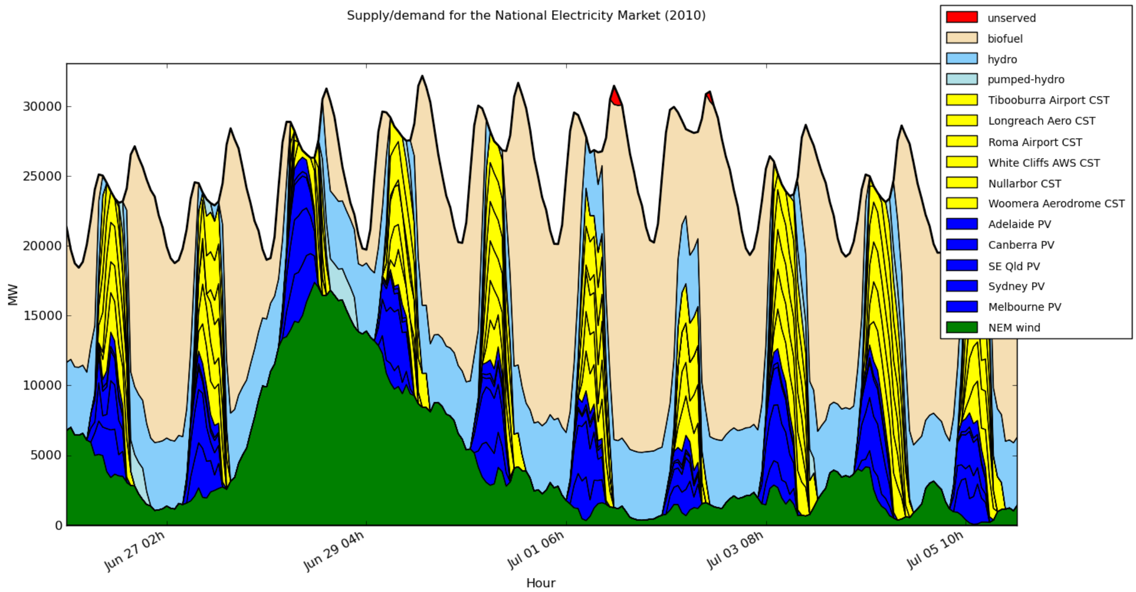

Figure 5.2: Supply and demand plot for the simulated NEM for a challenging week in June/July 2010

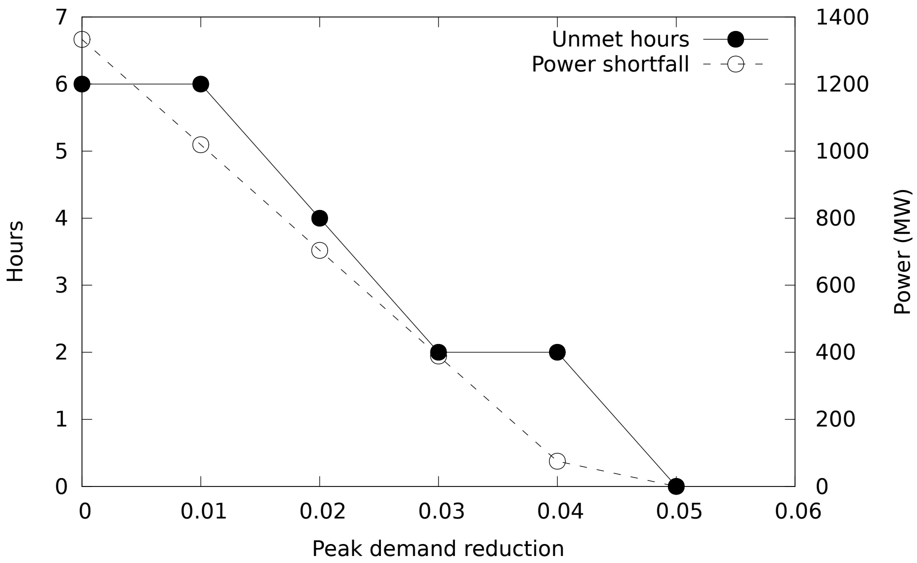

Figure 5.3: Effect of peak demand reduction on unmet hours with 24 GW peaking capacity

5.4 Sensitivity analyses

In this section, six sensitivity analyses examine various options for improving the reliability of the system or reducing the biofuel consumption through lower utilisation of gas turbines.

5.4.1 Eliminating unmet hours through demand reduction

The main challenge for a 100% renewable electricity system is peak periods when generation from variable sources may contribute little. How reliability is improved by actively managing load during these hours of otherwise unmet demand is examined. Figure 5.3 shows that a 5% reduction in the six demand peaks is sufficient to bring demand and supply into balance for every hour of the year. As these peaks occur on winter evenings, this reduction could be readily achieved through energy efficiency measures, particularly to reduce residential heating demand, or by temporarily interrupting controllable loads.

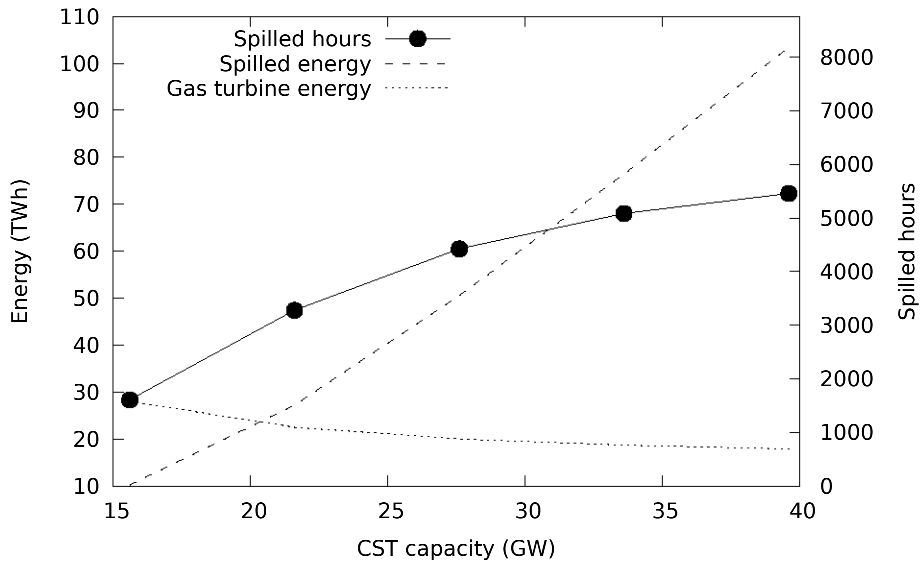

Figure 5.4: Effect of increasing CST capacity

5.4.2 Increasing solar thermal plant capacity

In the baseline simulation, CST plants have a total generating capacity of 15.6 GW. To overcome the decline in CST generation during winter and consequent increase in bioenergy consumption, the effect of oversizing the total capacity of CST plants is considered, keeping the solar multiple constant and the storage at 15 full load hours for the expanded CST generating capacity (Figure 5.4). This change reduces the number of unmet hours from six to two, reduces the gas turbine generation modestly, but increases total surplus energy significantly. This, and current high costs of CST technologies, suggest that increasing CST capacity could be a very expensive means of meeting peak demand in winter. However, it was the principal measure chosen in the single simulation reported by Wright and Hearps (2010).

5.4.3 Increasing CST solar multiple

Another strategy to reduce biofuel consumption was tested by increasing the solar multiple of the CST plants from 2.5 to 4.0, while keeping the CST generating capacity and storage capacity constant. In other words, the size of the solar field is increased. As Figure 5.5 shows, this change is much more effective than increasing

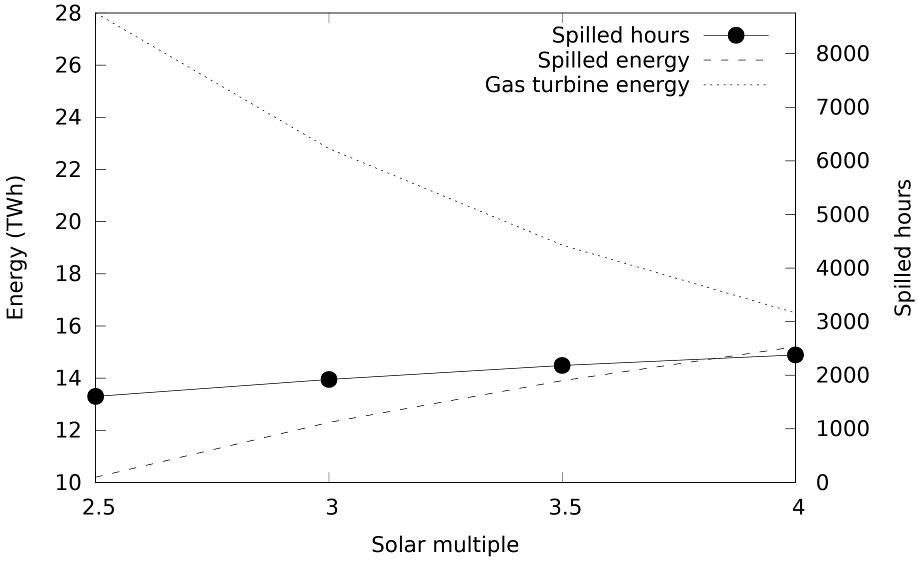

Figure 5.5: Effect of increasing CST solar multiple

the overall CST generating capacity in reducing gas turbine generation.

5.4.4 Delaying solar thermal dispatch

As Figure 5.2 shows, the dispatchable CST plants are not used to full advantage in meeting winter evening peak demand, increasing the capacity requirement for gas turbines. An alternative winter operating strategy for the CST plants is to delay the dispatch until the evening, so that peak generation coincides with evening peak demand.

Figure 5.6 shows the effect of delaying the dispatch of CST plants on the number of hours of unmet demand and the number of hours of surplus in the year. The minimum for both of these variables occurs at a delay of six hours, which corresponds to dispatching the CST plants such that peak generation occurs at 6pm (Australian Eastern Standard Time). This change has only a minor effect on the requirement for gas turbine generation. This is expected, as delaying dispatch is primarily intended to reduce gas turbine generating capacity rather than energy. Figure 5.7 illustrates how delaying CST dispatch influences the minimum gas turbine generating capacity and energy required to maintain the NEM reliability standard. Hence, the two curves in Figure 5.7 maintain constant reliability. The figure shows that delaying CST dispatch permits the gas turbine

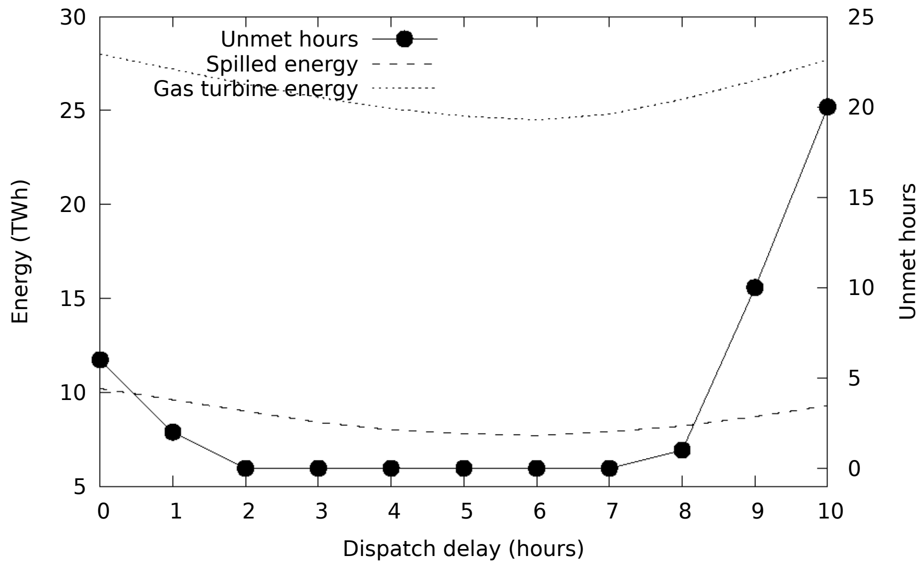

Figure 5.6: Effect of delaying CST dispatch on unmet hours and hours of surplus

generating capacity to be reduced, with the minimum capacity occurring with a five hour delay.

Figure 5.8 highlights how delaying CST dispatch creates different, complementary roles for CST with thermal storage and flat plate PV without storage. CST contributes more to the evening peak while PV contributes to supplying daytime demand. This is consistent with conclusions reported by Denholm and Mehos (2011).

5.4.5 Greater PV contribution

In Sections 5.4.2 and 5.4.3, two options were presented for decreasing the energy requirement from biofuelled gas turbines: increasing the CST generating capacity and increasing the solar multiple of the baseline CST capacity respectively. These options are expensive because they both involve building more solar collectors, currently the most expensive component of CST costs.

In the baseline scenario, the total energy provided by the two solar technologies is 50% of total demand (40% CST, 10% PV). The significant reduction in the price of PV modules in recent years raises the question of whether some of the CST generating capacity could be substituted with PV without affecting system reliability. In the simulation, when the energy contribution from PV is increased

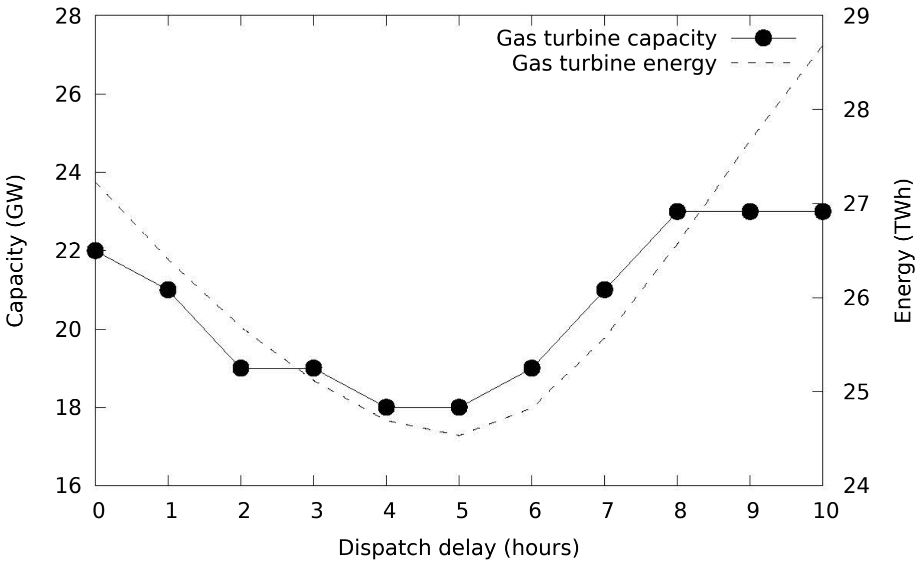

Figure 5.7: Effect of delaying CST dispatch on minimum gas turbine generating capacity and energy to maintain NEM system reliability standard

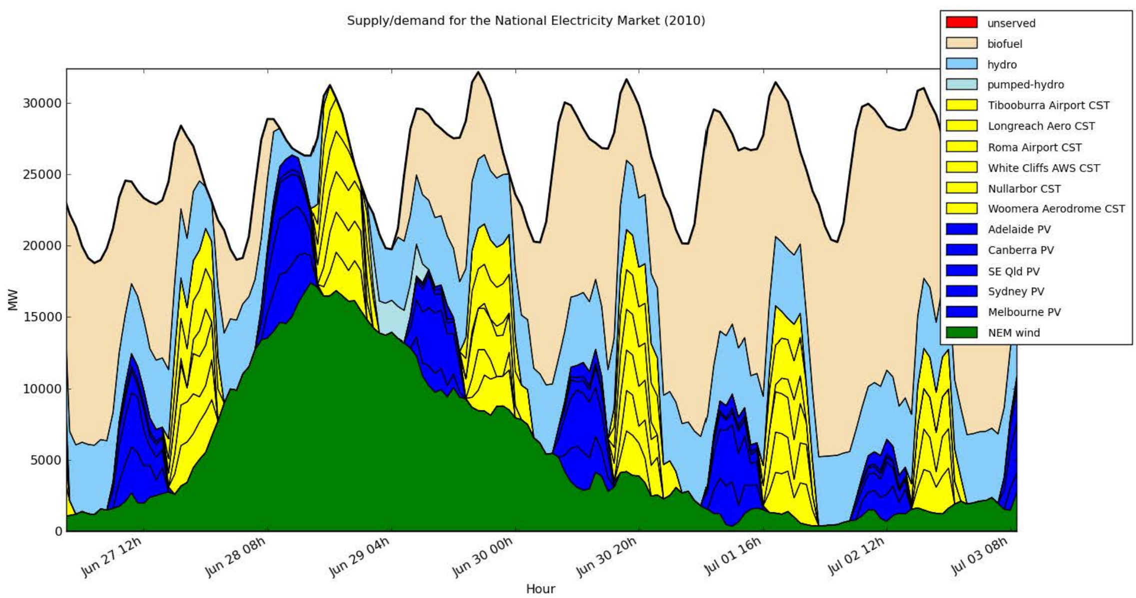

Figure 5.8: Supply and demand plot for the simulated NEM for a week with 7 hour dispatch delay

to 20% and CST reduced to 30%, system reliability is maintained. The large generating capacity of PV (29.2 GW), in combination with the baseline wind generating capacity, is frequently sufficient to meet demand around noon on summer days. This suggests that the idea of delaying the dispatch of CST plants in winter could also be applied in the summer months using CST plants with fewer hours of thermal storage.

5.4.6 Reducing peaking capacity through demand reduction

The initial capacity of the gas turbines was chosen somewhat arbitrarily for the baseline scenario, as these generators are the last to be dispatched – a consequence of the inherent energy storage of biofuels and the ability to readily dispatch this technology due to high ramp rates and fast start-up/shutdown times. A series of simulation runs were used to evaluate the effect of targeted demand response on reducing the required gas turbine capacity. For all of the unmet hours that arise with a given gas turbine generating capacity, demand was lowered until the NEM reliability standard was achieved (Figure 5.9). By reducing gas turbine generating capacity from 24 GW to 15 GW, the NEM reliability standard can be met if demand during the unmet hours is reduced by 19%. This result shows that a significant reduction in peaking capacity can be achieved with carefully designed demand-side policies. Energy from gas turbine generation is reduced by around 4%.

5.5 Discussion

These simulations provide a number of insights into the challenges of constructing a 100% renewable electricity system in Australia and possibly other regions with a high solar resource. An electricity supply system based primarily on generation that is not fully controllable leads to a supply that can be highly variable, producing excess power in times of low demand and occasional power shortfalls in times of high demand. As this work shows, the availability of RE sources is not always correlated with demand in ways that are helpful for such a system.

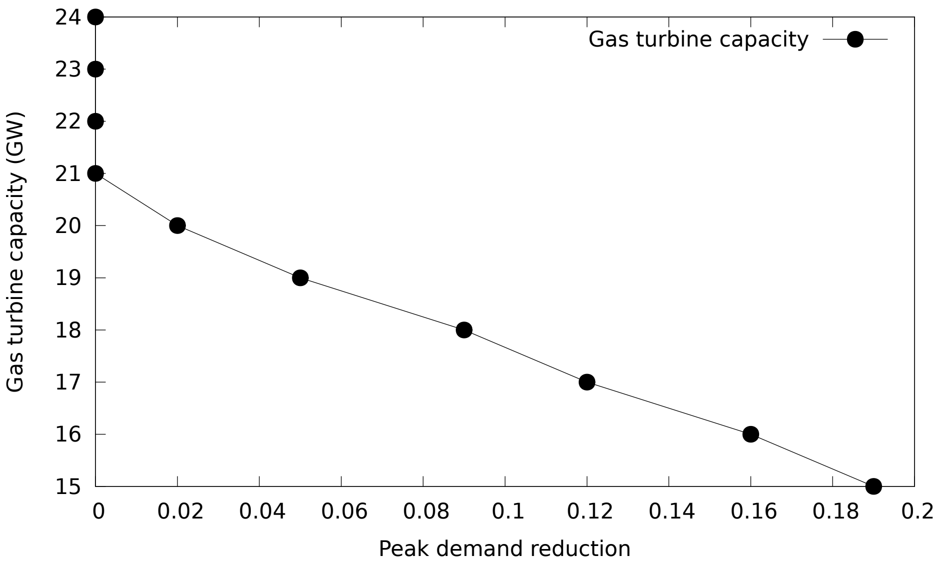

Figure 5.9: Impact of reducing peak demand on gas turbine generating capacity required to maintain NEM reliability standard

A particular challenge in the context of the NEM is, for example, calm winter evenings where both wind and solar resources are not available. It is reasonable to question whether a supply system based on a radically different mix of generation technologies should be expected to meet demand unmodified, or whether demand can be expected to accommodate to some degree the operating characteristics of the new system. The simulations show that small percentage reductions in peak-load demand in winter produce larger reductions in the required gas turbine generating capacity.

The simulated wind generation is based on actual generation data from the NEM in 2010 and the wind farm outputs at the various sites are quite strongly correlated. Currently, NEM wind farms are predominantly sited in South Australia and Victoria in the same wind regime. This situation could be improved by choosing a wider set of sites around the NEM for wind generation that reduces the correlation between individual wind farms. This is examined in Chapter 8.

With the exception of pumped hydro storage with its small capacity (2.2 GW, relative to peaks over 33 GW) and the biofuelled gas turbines, none of the generators in the mix could be described as being fully controllable. None provides firm capacity for 24 hours per day for every day of the year, although the CST plants can provide around the clock power during summer. In aggregate, however, the generation mix simulated here is able to meet power demand in almost all hours of the year (six shortfalls), with 10 TWh of surplus energy, and 28 TWh of electricity sourced from biofuels. This further demonstrates that generators with near-constant power output may not be required to meet demand even in a system with currently a very large baseload demand component. Instead, it is having sufficient capacity of dispatchable generators that is vital. This result is consistent with those of the studies on the integration of 20–30% wind energy into the eastern and western grids of the United States (National Renewable Energy Laboratory 2010, 2011).

In the present scenario, the limitations of existing NEM hydroelectric plants in supporting variable generation become apparent. First, the generating capacity (2.2 GW) and energy storage (20 GWh) of pumped storage hydro plants is very much less than the peak power demand and annual energy demand respectively of the whole NEM system. Likewise, the hydro plants without pumped storage have a limited generating capacity (4.9 GW). In reality, these hydro plants are placed low in the merit order to meet peak demands, but the benefit is limited when the supply shortfalls are large. In the simulation, rather than functioning as true peaking plants, the hydro plants serve to reduce the amount of biofuel consumed to operate the gas turbines. As mentioned in Section 5.2.1, it may be worthwhile to investigate whether there are suitable sites for expanding pumped hydro generating capacity, within the constraint of limited water availability for storage (Blakers et al. 2010).

While it is possible to meet more winter energy demand using greater levels of CST generating capacity, or increases in solar multiple, that is, the increased solar collector area to compensate for low levels of solar energy in winter, both of these options lead to very high power output and surplus energy in the summer months. As the analyses in the previous section have shown, solar generation in particular, has difficulty in year-round supply due to seasonal variations in solar radiation. In the case of CST and hydroelectric generation, storage is clearly beneficial. However, storage is only as valuable as the ability to charge it, so the siting and operation of storage is critical.

Approaching a 100% RE system requires particular attention to ensuring that short term supply and demand are balanced at all times. On those occasions when variable sources of renewable power (eg, wind and solar) are not available during high demand periods such as winter evenings, a large capacity of peaking plant is required to meet demand. Although peaking plant has the desirable properties of lower capital cost and higher marginal cost than other forms of generation, a system requiring very high levels of peaking capacity is likely to have a high cost. Mai et al. (2012) similarly found gas turbines to be a cost effective technology for meeting peak load. Lower cost alternatives may include increased diversity in renewable sources, more effective storage regimes, energy efficiency to reduce peaks in demand, and using pricing or direct load control to shift demand to better coincide with renewable generation.

It is instructive to consider what other benefits a 100% renewable electricity system might bring besides zero operational CO_2 emissions. Using wind power, PV, air cooled CST and gas turbines, and hydro would significantly reduce consumptive water use over the present, largely fossil-fuelled generation system which uses around 300 GL of freshwater per year for cooling (National Water Commission 2012; Turner et al. 2013). The distribution of RE resources, particularly solar energy, around the NEM is more uniform than the distribution of coal and gas reserves, providing the potential for jobs in all regions. Agricultural areas could become producers of food, wind power, and renewable gas injected into pipelines or gas turbines. Regional areas in sunny parts of the country could become the sites of CST power stations. In cities, households and businesses could continue to be involved in the production of photovoltaic electricity with PV panels installed in the built environment. Without fossil-fuelled generation, air quality and health outcomes could improve in towns near former mines and power stations.

5.6 Chapter summary

This chapter demonstrates that 100% renewable electricity in the NEM, at the current reliability standard, would have been technically feasible for the year 2010 given some particular RE generation mixes including high levels of variable resources such as wind and solar. This result is obtained by using RE technologies that are in mass production (wind, PV, hydro and biofuelled gas turbines) and a technology in limited commercial production (CST with thermal storage).

In a geographic region with high levels of insolation, solar energy sources, both CST and PV, can together make the major contribution to energy generation. Then the principal challenge is to generate sufficient power during the evening peak periods in the winter months. On some of these evenings there are lulls in the wind and insufficient energy in the CST thermal stores. One solution is to install a high capacity (24 GW) of peaking plant, which is around 2.5 times the peaking plant capacity in the NEM today. Although only 14% of total electrical energy is sourced from biofuels, the power requirements are large. Another solution is to increase the solar multiple of the CST power stations. Yet another solution is to delay the dispatch of CST power in winter, to improve the matching of supply and demand. Demand reduction measures, especially for the heating load on winter evenings, could prove to be the least-cost solution, however an economic analysis is needed to rank the options. The next logical question is answered in the following chapter: how much would such a system cost?

Chapter 6

Least cost 100% renewable scenarios

In the simulations described in the previous chapter, the capacities of the various renewable generators were chosen by 'guided exploration', ensuring that low marginal cost generation such as wind and concentrating solar thermal (CST) contributed a large share of generation, that bioenergy consumption was kept to low levels, and that the National Electricity Market (NEM) reliability standard was maintained. This chapter extends the work to investigate least cost options for supplying the NEM with 100% renewable electricity in 2030. Different scenarios of technology mix and locations were assessed through simulations of electricity industry operation. A genetic algorithm (GA) was used to identify the lowest investment and operating cost scenarios.

For the second phase of this study the simulation framework has been extended in three ways:

- the framework now calculates the overall annual cost of meeting demand in the simulated year including annualised capital costs, fixed operating and maintenance (O&M) costs, variable O&M costs and, where relevant, fuel costs;

- the framework can now make high level estimates of transmission costs associated with different spatial deployments of renewable energy (RE) technologies; and

- the framework can now be driven by a real-valued GA[1] to search for the lowest cost configuration in the simulated year that fulfills certain constraints such as meeting the NEM reliability standard.

Spatial mismatches between renewable electricity generation and demand may require an extensive reconfiguration of the transmission network. Australia is an increasingly urbanised country with 64% of the population living in the eight capital cities, mostly on the coast (Australian State of the Environment Committee 2011). The present transmission network is oriented towards fossil fuelled generators situated close to the points of fuel extraction (Figure 2.3). Some RE sources are more abundant in rural and remote regions of Australia. For example, the Eyre Peninsula of South Australia has high average wind speeds, and the centre of the continent has very high direct normal insolation by world standards. Transmission network refurbishment, expansion, and greater interconnection have been identified as urgent priorities for European countries to fulfill their renewable electricity objectives (Schellekens et al. 2011).

Chapter 5 contained a simplifying assumption that treated the NEM area as a 'copper plate': that is, power could flow unconstrained from any generator to any load in the NEM. Here, the 'copper plate' assumption is partially removed by separating the NEM into its five existing market regions and by introducing regional interconnections to the simulation framework. The regions are connected by a simplified transmission network with interconnectors between all adjacent regions. By accounting for regional energy exchanges, the balancing requirement between regions and the investment cost becomes evident. The ability to simulate the operation and overall costs of particular renewable technology portfolios, including transmission requirements, supports the use of evolutionary programming techniques to determine lower cost generation mixes through repeated simulations of a population of possible options.

The outline of this chapter is as follows. Section 6.1 provides an overview of the scenario used in this chapter. Section 6.2 presents the results of the search. As a preliminary basis for comparing a 100% renewable system with alternative

[1] Real-valued GAs use real numbers for chromosome values instead of binary digits.

scenarios, Section 6.3 calculates the annualised cost of a replacement generation fleet for the NEM, where each present power station is replaced with the most suitable fossil-fuelled substitute. Section 6.4 provides an analysis and discussion of the results.

6.1 Scenario overview

The scenario in Chapter 5 is now expanded to assign different RE sources to different NEM regions. These are listed in Table 6.1. Wind is aggregated in each region for 2010. For solar technologies, photovoltaic (PV) and CST generators are modelled at specific locations in 2010. The existing pumped storage hydro (PSH) and conventional hydroelectric stations are grouped into their NEM region. Gas turbine generation is also grouped, one simulated generator per NEM region. Note that capacities are not specified, as the GA will determine these in the least cost mix.

As hydroelectric stations typically have a very long design life (150 years), existing hydroelectric stations in the NEM are assumed to remain in all future scenarios and they are therefore excluded from the investment costings. As the potential for significant further expansion of hydroelectric energy generation is limited by a lack of water and environmental concerns (Geoscience Australia and ABARE 2010), the hydroelectric generating capacity is fixed in the simulations.

The genetic algorithm is described in detail in Section 4.7. Briefly, the objective function for the GA is the least cost mix of generation that fulfills three constraints: (i) meeting the NEM reliability standard by limiting unserved energy to 0.002% of annual demand, (ii) limiting hydroelectric generation to the long-term average of 12 TWh-e per year, and (iii) limiting electricity from bioenergy sources to 20 TWh-e per year. The generating capacity of each simulated generator is represented by one parameter in the GA. Using a GA has the advantage of permitting a large number of simulation parameters, which precludes exhaustive search approaches (Budischak et al. 2013).

Generator name	Region
VIC wind	VIC
SA wind	SA
NSW wind	NSW
TAS wind	TAS
Melbourne PV	VIC
Sydney PV	NSW
SE Qld PV	QLD
Canberra PV	NSW
Adelaide PV	SA
Woomera CST	SA
Nullarbor CST	SA
White Cliffs CST	NSW
Roma CST	QLD
Longreach CST	QLD
Tibooburra CST	NSW
QLD pumped hydro	QLD
NSW pumped-hydro	NSW
TAS hydro	TAS
NSW hydro	NSW
VIC hydro	VIC
NSW gas turbines	NSW
VIC gas turbines	VIC
QLD gas turbines	QLD
SA gas turbines	SA
TAS gas turbines	TAS

Table 6.1: Generators defined for the simulations

6.1.1 Technology costs

Table 6.2 lists the projected costs of the chosen RE technologies in the year 2030, taken from the Australian Energy Technology Assessment (AETA), a report by the Australian Bureau of Resources and Energy Economics (2012a). The AETA extensively examines the current and projected costs of 40 electricity generation options in Australian conditions. The Bureau of Resource and Energy Economics has stated its intention to revise the cost data every six months with an update publication issued annually and a complete report, as in 2012, issued biennially. An update was released in January 2014 (Bureau of Resources and Energy Economics 2013a), although its publication was too late to consider in detail in this thesis.

For each technology, the AETA includes capital cost for 2012, a range of projected capital costs for 2030, fixed O&M, variable O&M and levelised cost of energy. These data offer the advantage of currency, transparency and consistency of assumptions, although some figures (eg, the projected capital cost of CST) are contested (Want 2012; Beyond Zero Emissions 2012). Despite these concerns[2], the AETA figures are used for consistency with broadly accepted government and industry expectations. The AETA is now also the source of generation cost data for the Australian Energy Market Operator (AEMO) National Transmission Network Development Plan (NTNDP).

The AETA provides cost data for CST plants with six hours of thermal storage and a solar multiple of 2.0. As the simulations are based on CST plants with 15 hours of storage and a solar multiple of 2.5, the CST capital cost was adjusted. The AETA provides a breakdown of CST component costs: 33% for the solar field and 10% for storage. The capital cost of the simulated CST plant was derived by scaling the solar multiple by 1.25 and the storage by 2.5. Therefore, the range of CST costs listed in the table are derived from AETA data.

[2]As just one example, AETA assesses the fixed O&M costs of on-shore wind at $40/kW/yr and variable O&M costs at $12/MWh. For a wind farm with a capacity factor of 0.3, this leads to average O&M costs of $27/MWh. United States data suggest that total O&M costs of $10/MWh were achieved in the 2000s, with wind farms as recently as 2008 achieving total O&M costs below $10/MWh (International Renewable Energy Agency 2012c).

Throughout this chapter, the two ends of the AETA cost range, termed *low cost* and *high cost*, are used for sensitivity analysis[3]. In the low cost scenario, the lowest capital cost in the range is chosen for each technology. Similarly, the high cost scenario selects the highest estimated capital costs. These two scenarios provide a lower and upper bound for the projected capital costs of an entire generating fleet[4].

6.1.2 Discount rates

Sensitivity analyses were performed using two discount rates: 5% and 10%. This gives a total of four scenario combinations, with each scenario requiring one optimisation run. The 5% discount rate is chosen as a social discount rate and the 10% rate as a private discount rate. Although the evolving electricity supply system in Australia is likely to be built by the private sector, low emissions generation will confer significant benefits to future generations and so a social discount rate may be more appropriate.

The choice of discount rate is vigorously debated in the literature. Harrison (2010) describes two approaches to choosing a discount rate, the 'descriptive approach' where the discount rate is influenced by the opportunity cost of capital in private markets and the 'prescriptive approach' based on value judgements about the welfare of future generations. The main recommendation that Harrison (2010) makes, however, is to perform sensitivity analyses with a range of discount rates to assess the viability of a project. A discount rate of 5% is higher than the social discount rates advocated by others in avoiding damage from climate change (Stern and Stern 2007; Garnaut 2011b). Conversely, a discount rate of 10%, as used in the AETA, is a private discount rate appropriate for a higher degree of investment risk and is higher than would be used for most commercial investments.

Australia has comparatively little experience with the construction of large-scale

[3]Four digit precision in the projected 2030 capital costs is inappropriate, given the uncertainties involved.

[4]O&M costs in the AETA report are not given as ranges.

Technology	Efficiency (GJ/MWh)	Capital cost ($/kW)	Fixed O&M ($/kW/yr)	Var. O&M ($/MWh)
Supercritical black coal	8.57	2947–3128	59	8
Supercritical brown coal	10.59	3768	71	9
CCGT	6.92	1015–1221	12	5
OCGT (fossil gas)	11.61	694–809	5	12
OCGT (biofuel)	11.61	694–809	5	92
On-shore wind		1701–1917	40	14
CST		5622–6973	65	23
PV		1482–1871	25	0

Table 6.2: Estimated costs in 2030 for selected generating technologies (2012 $). 2012 operating and maintenance costs are increased by 17.1%. Source: Bureau of Resources and Energy Economics (2012a)

renewable electricity plant, in contrast to countries considered to be forerunners in the transition to RE. As of late 2013, Australia has operational wind farms with a rated capacity of around 2.6 GW, no operating CST plants of significant capacity, and the largest PV plant (under construction) has a rated capacity of 20 MW. Consequently there is little empirical data available on the costs of deploying these technologies in Australia.

Typically, European data such as those published by the International Energy Agency (IEA) and the International Renewable Energy Agency (IRENA) have been the main sources of data for Australian research. Projects commencing in Australia are likely, at least initially, to have quite different costs to projects undertaken in more experienced countries. The timeliness of data is also increasingly important due to the rapidly falling costs of some renewable technologies. The International Renewable Energy Agency (2012c) notes that, 'even data one or two years old can significantly overestimate the cost of electricity from renewable energy technologies'.

6.2 Search results

A series of GA runs showed that the aggregate capacity and energy generated by each technology remained similar from run to run. Some variation in the aggregate energy generated by each technology can be attributed to differences in capacity factors achieved by identical generators sited in different locations. The allocation of generators to regions can vary significantly when there is no cost associated with transmission. Figure 6.6 shows the performance of the GA on a single run, converging on a solution within 70 generations. Each plotted point represents the minimum value of the evaluation function at the end of each generation. Average and maximum fitness values are not shown as the penalty functions can produce excessively large values.

Table 6.3 lists the aggregate capacity and energy served by each renewable technology in the fittest (ie, the least cost) mix. Table 6.4 provides annualised costs for 100% renewable electricity fleets for three variables: discount rate, low/high cost for renewable technologies, and whether transmission costs are included. The reliability of the fittest configurations is shown in Table 6.5. The supply shortfalls are not significant and could be addressed by briefly shedding large industrial loads. Table 6.6 enumerates the loss of load events in 2010 for each scenario. Figures 6.1 to 6.5 show how supply and demand are balanced with the least cost mix, optimised over a year, on a range of days in January, April, July, August and November 2010. The plots for this least cost mix are very different to the plots of the 'guided exploration' mix in Chapter 5. Surplus energy from a generation source is shown above the solid demand line in a lighter shade of the designated colour in the legend. There are numerous instances throughout the year when there is surplus wind power in the least cost generation mix. Three hours of unmet demand are indicated in red in Figure 6.3. Note that in the summer months (Figures 6.1 and 6.5), CST is not always dispatched over the midday hours. The simulated CST generators instead collect heat for dispatching power later in the day, usually when PV power declines.

A number of observations can be made about the generation mixes found by the GA. On-shore wind is the largest contributor to annual energy supply. In the low cost scenario, wind represents around 46% of total energy supply and around 58% in the high cost scenario. Wind is deployed to such a great extent due to its relatively high capacity factor and because it is one of the lower capital cost technologies available. Reliability is achieved with the coordination of the

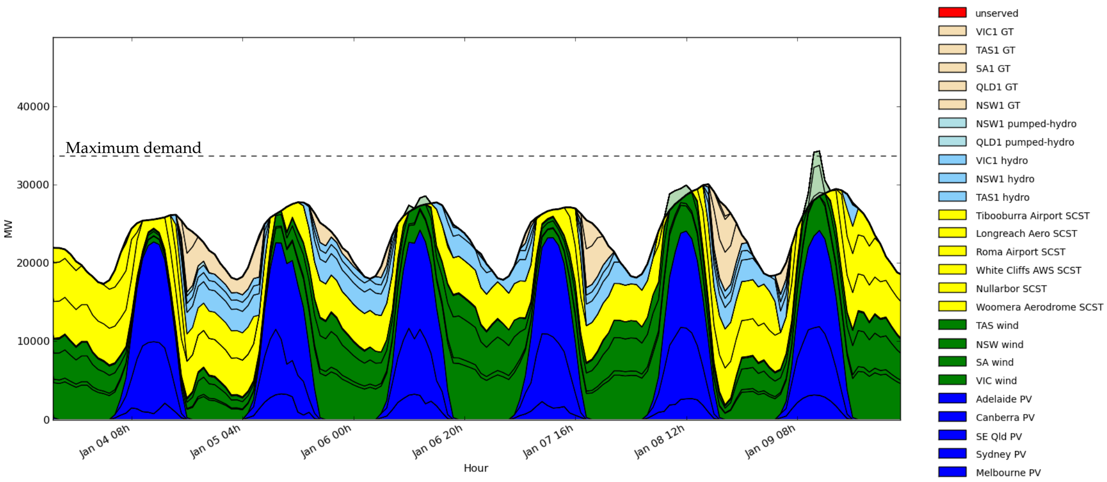

Figure 6.1: Hour by hour plot of the least cost system in January 2010 (low cost scenario, 5% discount rate). Surplus energy shown in lighter shade above solid demand line.

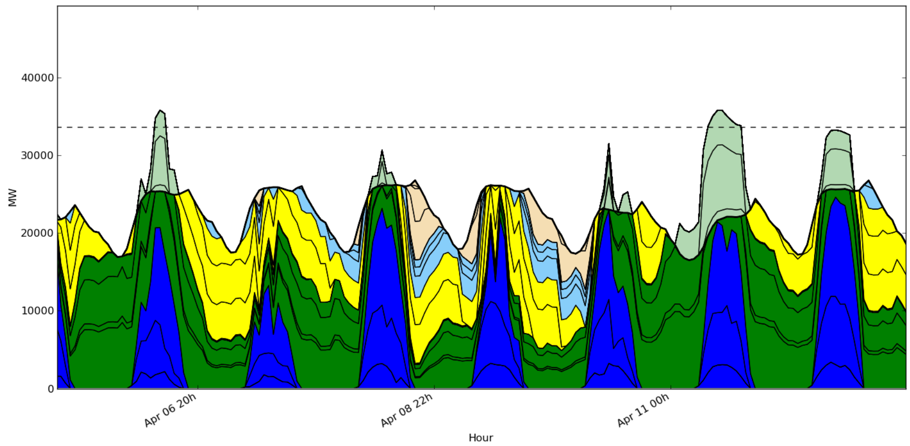

Figure 6.2: Hour by hour plot of the least cost system in April 2010

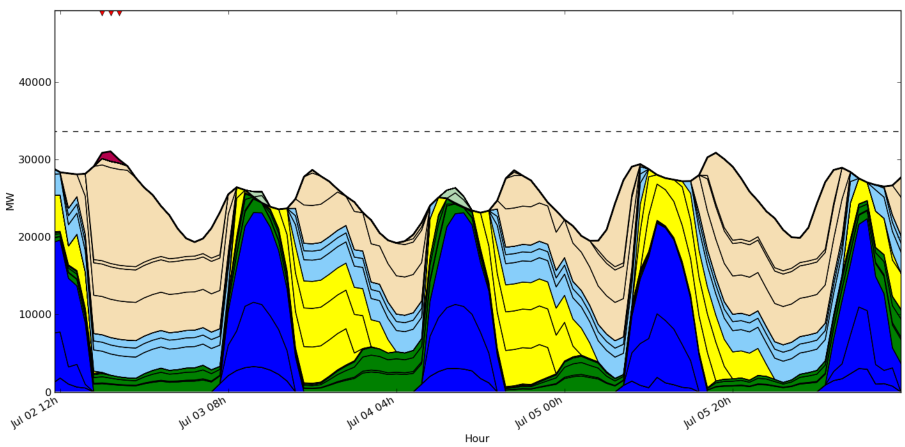

Figure 6.3: Hour by hour plot of the least cost system in July 2010 (red markers show unserved demand)

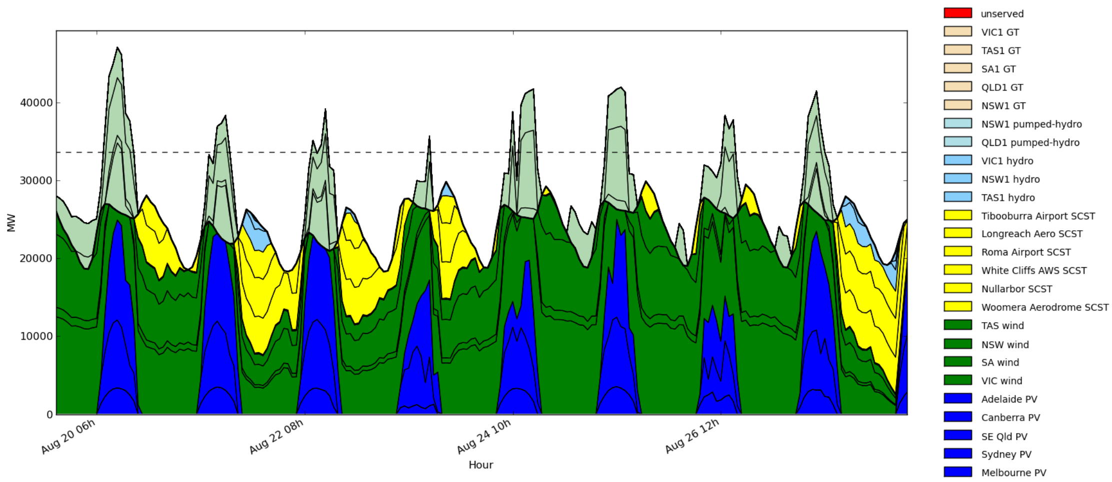

Figure 6.4: Hour by hour plot of the least cost system in August 2010

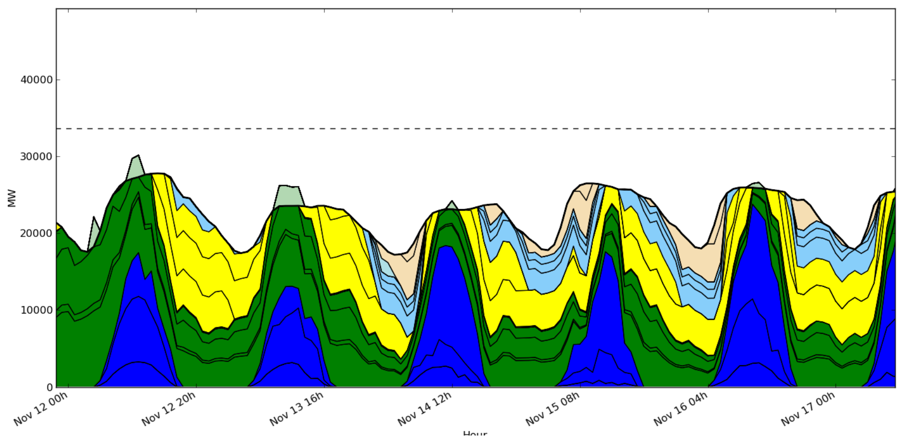

Figure 6.5: Hour by hour plot of the least cost system in November 2010

whole generating system, even with a high fraction of downward dispatchable generation. The generation mix in Table 6.3 is in agreement with the technology mix found for world-wide RE supply in Jacobson and Delucchi (2011): 50% wind, 20% PV, 20% CST, 4% hydroelectricity and 6% from other sources. In that study, the need to balance demand using a diversity of more costly energy sources was recognised.

In the high cost scenarios, significantly more energy is surplus as a result of the large contribution from relatively low cost, downward dispatchable generation. This occurs despite the availability of higher cost, dispatchable generation, demonstrating that in some cases, RE over-generation can be economically optimal. This agrees with a conclusion of Budischak et al. (2013), that least-cost generation mixes may involve significant over-generation because storage to reduce the incidence of surplus generation may not be cost effective. Budischak et al. (2013) also suggests that some value of this surplus electricity can be recovered by diverting it to thermal loads, thereby potentially displacing fossil fuel use in other sectors.

In the high cost, 5% discount rate scenario, 9.4 GW of CST plant generates 13.8% of total energy, illustrating that, despite the high capital costs in this study, CST power plays a valuable role in providing low marginal cost, flexible and dispatchable generation (Denholm et al. 2012), and in limiting the use of gas turbines fuelled with a constrained bioenergy resource. In all scenarios, the gas turbines produce 6.2–7.1% (12.6–14.5 TWh) of annual energy from bioenergy sources such as crop residues. Geoscience Australia and ABARE (2010) have estimated the potential for electricity generation just from grain and cotton crop residues in 2050 at 47 TWh-e per year. If other major sources of agricultural wastes such as bagasse are included, the resource is estimated at over 54 TWh-e per year. If public support for bioenergy use in electricity generation is to be ensured, the sustainability of bioenergy sources will need to be carefully managed.

The capacity of the gas turbines ranges from 22.3–23 GW, or around 63% of the maximum demand (35 GW). Hart and Jacobson (2011) have previously identified the potential new role for dispatchable plants in a high penetration renewable system, whereby 'reliable capacity is valued over energy generation'. In discussing the potential for large-scale electrical storage to replace fossil-fuelled peaking plant in the California Independent System Operator (CAISO) simulations, Hart and Jacobson (2012) find that the capacity of this storage would need to be around 65% of the peak demand. Although taken from a different locality, these results are broadly consistent.

The ability to supply 50% of electricity in 2030 (with 2010 demand and weather data) from wind power is dependent on wind conditions for that year. It is likely that this high reliance on wind power could produce more supply shortfalls in other years, although there is more research to be done to produce a high resolution wind climatology for the Australian continent over a longer period. No wind farms are simulated in the Queensland region because the only significant wind farm in Queensland (12 MW) is not required to publish generation data. Relocating some amount of wind capacity into northern Queensland reduces the cross-correlation of wind power with existing wind farms in South Australia and reduces periods of very low and high wind output. This is discussed further in Chapter 8. High penetrations of wind power in the NEM should be possible given appropriate market rules and policies that facilitate integration (MacGill 2010). However, a 50% wind energy contribution would be challenging for power system operation.

6.2.1 Energy exchanges

When including the cost of transmission in the optimisation, the peak energy exchanges in Table 6.8 are observed. A more interconnected transmission network significantly reduces the peak energy exchanges between certain regions, particularly between South Australia (SA) and Victoria. Victoria is a region with high annual electricity demand, second only to New South Wales (NSW). South Australia is a region that can host a high level of the relatively low cost wind power, which features high in the merit order. By introducing two new interconnections from South Australia (the dashed lines in Figure 4.8), a lower overall cost of transmission is achieved because this energy can be delivered via a shorter

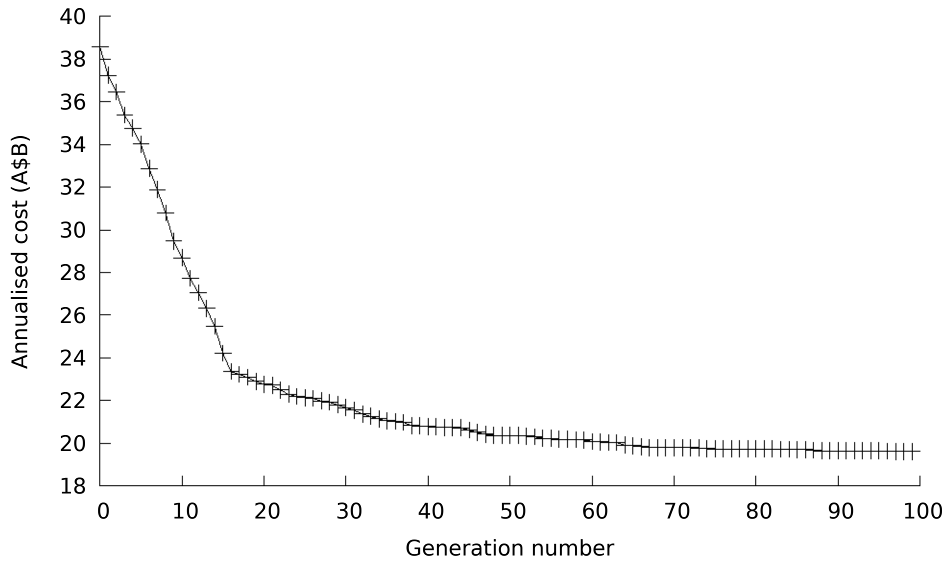

Figure 6.6: Annualised cost of the best population member in each generation of a single run of the genetic algorithm

Technology	Low cost scenario Cap. (GW)	Share (%)	Energy (TWh)	Share (%)	High cost scenario Cap. (GW)	Share (%)	Energy (TWh)	Share (%)
5% discount rate								
Wind	34.1	31.9	94.8	46.4	47.1	41.4	119.7	58.6
PV	29.6	27.7	41.0	20.1	27.6	24.2	31.3	15.3
CST	13.3	12.5	43.9	21.5	9.4	8.3	28.2	13.8
Pumped hydro	2.2	2.1	0.5	0.2	2.2	1.9	0.8	0.4
Hydro	4.9	4.6	11.5	5.6	4.9	4.3	11.1	5.4
GTs	22.7	21.3	12.7	6.2	22.7	19.9	13.3	6.5
Surplus			8.8				24.9	
10% discount rate								
Wind	35.1	33.9	97.4	47.7	46.0	39.4	117.9	57.7
PV	24.3	23.5	34.3	16.8	32.6	27.9	35.7	17.5
CST	13.9	13.4	46.2	22.6	8.8	7.5	26.1	12.8
Pumped hydro	2.2	2.1	0.4	0.2	2.2	1.9	1.1	0.5
Hydro	4.9	4.7	11.5	5.6	4.9	4.2	11.0	5.4
GTs	23.0	22.2	14.5	7.1	22.3	19.1	12.6	6.2
Surplus			6.8				27.1	

Table 6.3: Capacity and energy mix for the fittest individual generating system (four scenarios). Transmission costs excluded.

Discount rate	Low cost		High cost	
	($B/yr)	($/MWh)	($B/yr)	($/MWh)
5%	19.6	96	22.1	108
10%	27.5	135	31.5	154

Table 6.4: Least cost 100% renewable generating systems in 2030 (2012 $) excluding long-distance transmission

Scenario	Hours unserved	Min. shortfall (MW)	Max. shortfall (MW)
5% discount rate			
Low cost	5	473	1294
High cost	8	104	1032
10% discount rate			
Low cost	8	136	920
High cost	7	47	891

Table 6.5: Reliability statistics for the fittest generating systems

Date	5% discount rate		10% discount rate	
	low cost	high cost	low cost	high cost
June 1		6–7 pm		
June 15			6–7 pm	
June 21		5–7 pm	5–7 pm	
July 1		6–8 pm	6–8 pm	6–8 pm
July 2	5–8 pm	6–7 pm	6–8 pm	6–8 pm
July 5				7–8 pm
July 7	7–9 pm	7–9 pm	8–9 pm	8–9 pm
Contiguous events	2	5	5	4
Longest event (hours)	3	2	2	2

Table 6.6: Loss of load events in 2010 for each scenario

Discount rate	Low cost		High cost	
	($B/yr)	($/MWh)	($B/yr)	($/MWh)
5%	21.2	104	24.4	119
10%	31.2	153	35.4	173

Table 6.7: Least cost 100% renewable generating systems in 2030 (2012 $) including long-distance transmission

	NSW	QLD	SA	TAS	VIC
NSW		8.4	4.5		9.6
QLD	8.5		3.1		
SA	7.8	8.6			4.7
TAS					2.0
VIC	10.7		6.6	1.5	

Table 6.8: Peak energy exchanges over one hour (GWh) between regions

path. This eliminates the very high peak energy exchanges that are otherwise seen between South Australia and Victoria.

Very large energy exchanges are found to occur between different regions to balance the availability of renewable generation with demand around the NEM. The idea of operating the grid in this way is already being explored in the European context (Schleicher-Tappeser 2012; Rodríguez et al. 2014). Referring to Table 6.8, some of the largest peak energy exchanges occur between the most populous states of New South Wales and Victoria.

The cost of a transmission network to facilitate this is not particularly burdensome when considered in the context of the total cost of either the 100% renewable electricity system or the replacement fossil-fuelled fleet (Section 6.3). The annualised cost of including the simplified transmission network is \$1.6 billion to \$3.9 billion per year depending on the discount rate, or 8% to 11% of the total cost of the 100% renewable system (Table 6.4). When RE costs are taken to be at the lower end of the range of uncertainty, the transmission network represents a greater share of the total cost.

Delucchi and Jacobson (2011) performed a sensitivity analysis on transmission costs for a range of price estimates and transmission distances, finding that the cost of transmission would add between US\$3 and US\$30 per MWh to the delivered cost of electricity, with the best estimate being about US\$10 per MWh. Despite using a different methodology for estimating transmission costs, similar results were obtained in the present research: \$8 to \$19 per MWh (see Table 6.7). Similarly, Czisch (2011) similarly found that the cost of transmission in a trans-European renewable electricity system is about 7% of total costs.

6.3 Estimating the replacement cost of the NEM

In considering the cost of a 100% renewable system for the NEM, it is necessary to compare this with alternative future scenarios. Much of the existing plant in the NEM will reach the end of its economic life in the next two decades. In this section, the cost of a new fossil-fuelled generation fleet is calculated for the NEM, where every existing power station is replaced with current thermal plant technology at projected 2030 costs. These are compared with the 100% renewable system costs. A price is paid on all greenhouse gas emissions from the fossil-fuelled fleet and it is assumed there is no capturing of emissions.

In this scenario, fuel costs are assumed to remain the same for the location of each plant and projected fuel prices out to 2030 are taken from data produced by ACIL Tasman (2009). The minimum, average and maximum projected fuel prices for each fuel type are listed in Table 6.9. These projections predict stable or slightly declining prices for brown and black coal in Australia to 2030, reflecting the poor economics of exporting coal from many of the current mining locations. Brown coal in the southern state of Victoria is not exported and is unlikely to be in the future. Black coal, found more widely across the country, is exported from some regions, but in others, prices are set based on the cost of local production (International Energy Agency 2012a). These prices are well below the market prices faced by fossil fuel importing regions today. The Organisation for Economic Co-operation and Development (OECD) average price for black coal is US $5.60/GJ (International Energy Agency 2012a).

Similarly, natural gas exports are presently constrained by the availability of export infrastructure and therefore some gas is sold domestically below international prices. However, the average price of natural gas available to power stations is expected to rise from around $3/GJ today to over $7/GJ in 2030. This is still below the price paid for natural gas imports in Europe ($9/GJ) and Japan ($14/GJ) today (International Energy Agency 2012a). Fossil fuels in Australia are cheap and abundant by world standards.

Using annualised capital costs avoids treating the current generation fleet as

Fuel type	Min.	Avg.	Max.
Black coal	0.76	1.29	2.13
Brown coal	0.08	0.70	2.00
Natural gas	0.95	7.61	12.25

Table 6.9: Projected 2030 location-specific fuel prices for all NEM power stations ($/GJ)

a sunk cost and allows for a full appreciation of the costs of constructing, maintaining and retiring plant in the current generation fleet. Existing hydroelectric stations are excluded from the costings for the reasons outlined in Section 6.1.1. The present NEM wholesale market currently trades around $10 billion of electricity each year excluding the cost of emissions. Assuming that generators are pricing electricity to recover all costs and make a profit, $10 billion should be indicative of the long-run annual cost of operating the generating fleet[5].

The annualised cost of the existing generation fleet was estimated using data from ACIL Tasman (2009) and costs from the AETA. For each registered generator in the NEM, the ACIL Tasman (2009) data set provides values for technical lifetime, thermal efficiency, location specific fuel cost and emission factors. The AETA data is used for costs of new entrant plant including annualised capital cost (2012 $/kW/yr), fixed O&M and variable O&M. These new entrants represent modern thermal plant technology with higher thermal efficiency, lower fuel consumption, and lower emissions per megawatt-hour of electricity generated than currently operating plant. In general, fuel costs out to 2030 were largely unchanged. Relevant costs are given in Table 6.2. Fuel costs are not included in the table for fossil fuel plants, as these are sensitive to the power plant location. Biofuel costs for the gas turbines are included in the variable operating and maintenance (VO&M) costs.

For each fossil-fuelled plant in the NEM, the closest suitable replacement was chosen from the available new entrants. In some cases, a straightforward replacement was possible (eg, a supercritical thermal plant fuelled with black coal). In many cases, a direct replacement was not possible and the closest suitable replace-

[5]This cost does not include most transmission and distribution network expenditure, which is recovered from end users in the NEM retail market.

ment was chosen instead (eg, a supercritical brown coal plant to replace a 1970s era subcritical brown coal plant). In each case, the fuel type remains unchanged to reflect the availability and economics of the local fuel supply. In a limited number of cases, the choice of replacement is less straightforward. The following three assumptions were made:

- steam turbines fuelled by natural gas are replaced with combined cycle gas turbines (CCGTs);
- smaller plant such as reciprocating engines running on landfill gas or liquid fuels are replaced with open cycle gas turbines (OCGTs); and
- the two co-generation facilities in the NEM are replaced with CCGT technology.

The short run marginal cost (in \$/MWh) for each plant in the replacement fleet was calculated using the following equation, adapted from ACIL Tasman (2009):

$$\mathrm{SRMC_{SO}} = \mathrm{TE_{SO}} \cdot \mathrm{FC} + \mathrm{V} + \mathrm{TE_{SO}} \left(\frac{\mathrm{EF_c} + \mathrm{EF_f}}{1000} \right) \mathrm{CP}$$

where TE_{so} is the thermal efficiency (sent out) in GJ/ MWh, FC is the fuel cost in \$/GJ, V is variable operating and maintenance costs in \$/MWh, EF_c and EF_f are the combustion and fugitive emission factors in kg CO_2/GJ respectively, and CP is the carbon price in \$/t CO_2.

Electricity generated in 2010 by each existing power station in the NEM is determined by summing historical five minute dispatch data obtained from AEMO. To avoid penalising the existing fossil fuel system by including the cost of plant to maintain mandated reserve margins, any power station that generated zero energy in 2010 is excluded. The cost of replacement and operation for three selected power stations in the NEM is given in Table 6.10.

In 2010, the NEM produced approximately 193 Mt CO_2 due to combustion and fugitive emissions. The current fleet of thermal plant are generally well into their economic life, most being commissioned over 20 years ago. In one instance, the Energy Brix power station in Victoria was commissioned over 50 years ago and

	Bayswater	Hazelwood	Newport
Fuel type	Black coal	Brown coal	Gas
Capacity (MW)	2720	1640	500
Capital cost ($M/yr)	1010.9	771.5	59.7
Fuel cost ($/GJ)	1.31	0.08	4.08
SRMC ($/MWh)	39.11	32.97	42.00
Energy (TWh)	14.46	11.48	0.25
Operating cost ($M/yr)	565.7	378.7	10.6
Emissions (Mt)	12.2	11.3	0.1

Table 6.10: Costs for three replacement power stations in 2030 (2012 $, $23/t CO_2 carbon price, 10% discount rate). Data source: ACIL Tasman (2009)

has low thermal efficiency. By replacing the current thermal plant with modern equivalents, NEM emissions for 2010 would be reduced to 156 Mt CO_2, a 19% reduction. This is broadly consistent with figures produced by the IEA Clean Coal Centre (2012).

6.3.1 Externalities and subsidies

The only negative externality that is incorporated into the cost of the replacement fleet is greenhouse gas emissions. There are other negative externalities whose costs are already being paid indirectly by society including air pollution, water pollution and land degradation. Another major public concern is the effect of fossil fuel combustion on mortality and morbidity (Kjellstrom et al. 2002; Muller et al. 2011). The total health burden of electricity generation in Australia has been estimated at $2.6 billion per year (Australian Academy of Technological Sciences and Engineering 2009).

Subsidies in the Australian fossil fuel industry are also ignored in the costings, however these are believed to be of the order of $10 billion per year across the entire energy industry, principally the liquid fuel sector (Riedy and Diesendorf 2003; Riedy 2007). Specific subsidies to the electricity sector include low cost electricity to aluminium smelters creating 13% of electricity demand (Turton 2002) and access to cooling water at very low cost (Foster and Hetherington 2010). There are current plans for a state-owned coal mine in NSW to supply coal to generators at the cost of production (Tamberlin 2011). These subsidies are provided to a mature and profitable industry with few, if any, conditions that would lead to their phase out.

RE in Australia presently receives subsidies in the form of feed-in tariffs and tradeable RE certificates. These instruments are intended to transition the technologies from early stages of the product life cycle to maturity. These and other subsidies take one of two forms: research and development (R&D) funding for technologies in early stages of development, and deployment subsidies to accelerate cost reductions through learning. Deployment subsidies are usually provided on the basis that they are progressively reduced. Recent experience world-wide, including in Australia, is that subsidies have been reduced rapidly or phased out in response to the falling cost of some technologies, particularly PV.

6.4 Discussion

6.4.1 Sensitivities

The sensitivity analyses presented in the Section 6.2 highlight a number of key issues for 100% renewable electricity. Using the cost data from the AETA, wind contribution is increased in the high cost scenarios because of the narrower range of costs for wind power, making it relatively cheaper to the other options. Wind power is one of the most mature RE technologies. While there are still future cost reductions predicted, these are not as significant as for other technologies. This serves to narrow the range of uncertainty about future costs. In high cost scenarios, the share of PV and CST declines.

Due to the generation profile of rooftop PV, and without electrical storage, the penetration of PV is limited to about 20% – regardless of its cost. Hence, without storage, incentives to further reduce the cost of PV may not enable 100% renewables. It is important to reduce the cost of other commercially available technologies too (eg, CST).

The generation mix is not particularly sensitive to the discount rate. When simulating a single year, O&M costs of generation are not discounted as would

Discount rate	$23/t CO_2		$100/t CO_2	
	($B/yr)	($/MWh)	($B/yr)	($/MWh)
5%	15.3	75	27.3	133
10%	19.4	95	31.4	154

Table 6.11: Replacement scenario costs in 2030 (2012 $), low end of cost range

be the case in a multi-decade analysis. Furthermore, in each sensitivity analysis, the discount rate is used to calculate annualised capital costs for each renewable technology. Dividing the capital cost of each technology by a constant annuity factor does not change the relative costs of the different technologies in each analysis. The main effect of a varied discount rate is to change the relationship between annualised capital costs and O&M costs for each technology.

6.4.2 Implications for Australia

Assuming that the application of a higher carbon price ($50 per tonne CO_2) would not have altered plant dispatch in 2010, emissions from the existing NEM generating fleet of 190 megatonnes (Mt) would have produced a carbon liability of $9.5 billion in 2010, bringing the cost of the current system ($19.5 billion) in line with the lowest cost scenario for a 100% renewable system. At carbon prices above $50 per tonne CO_2, rebuilding the NEM generating fleet with RE becomes the lower cost option. Diesendorf (2014) has suggested that the additional annual cost ($7–10 billion per year) of operating a 100% renewable electricity system compared with the efficient fossil-fuelled scenario discussed in Chapter 6 is less than the subsidies to fossil fuels in Australia each year (Riedy 2007).

Table 6.11 shows the estimated costs (annualised cost and cost per MWh) for the replacement scenario in 2030, as a basis for simple comparison with Table 6.4 for the 100% renewable case. Only costs calculated using the low end of the AETA range of capital cost estimates are included in Table 6.11, as the capital cost range in AETA is narrow for conventional technologies. Annualised costs and costs per MWh are shown for two carbon prices. Figures 6.7 and 6.8 show the cross-over points for the annualised cost of the replacement fleet and the optimised 100% renewable system at discount rates of 5% and 10%, respectively. The figures show

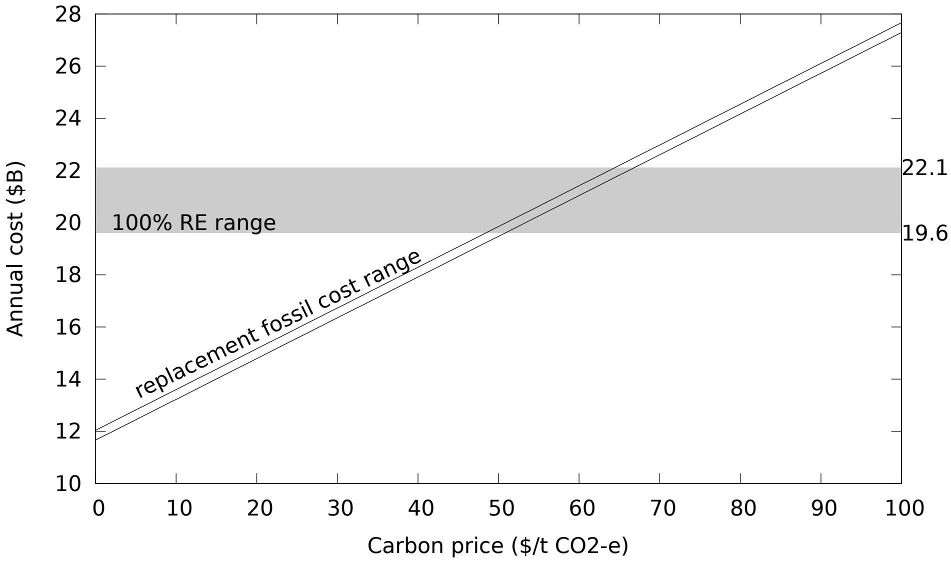

Figure 6.7: Annual costs for replacement fossil and least-cost renewable generating systems in 2030 as a function of carbon price (5% discount rate). Transmission costs excluded.

a range of uncertainty in the required carbon price to reach the cross-over point, principally due to uncertainty in the future cost of RE technologies (low and high cost scenarios). In the 5% discount rate case, the fossil fuel system is more costly on an annualised basis when the carbon price exceeds the range \$50–\$65. With a 10% discount rate, the fossil fuel system is more costly when the carbon price exceeds the range \$70–\$100. When comparing the projected 2030 capital costs of wind, solar PV and CST in the AETA with other international sources such as the International Renewable Energy Agency (2012a,b,c), the annualised costs of the 100% renewable scenarios in the Australian context are likely to be pessimistic.

The range of uncertainty in the cost of the fossil fuel system is much narrower than in the RE systems (Figures 6.7 and 6.8). This is because the replacement fossil system remains dominated by coal and forecasts by ACIL Tasman (2009) project stable coal prices around the NEM over the next two decades. Future fuel costs could be more uncertain than the ACIL Tasman (2009) data suggests. Ball et al. (2011) reports that the fuel cost for NEM generators would be 'considerably more' if generators faced international prices for black coal and natural gas. Liquefied natural gas terminals will soon be opening on the eastern coast of Australia, giving domestic natural gas producers access to potentially higher prices on the

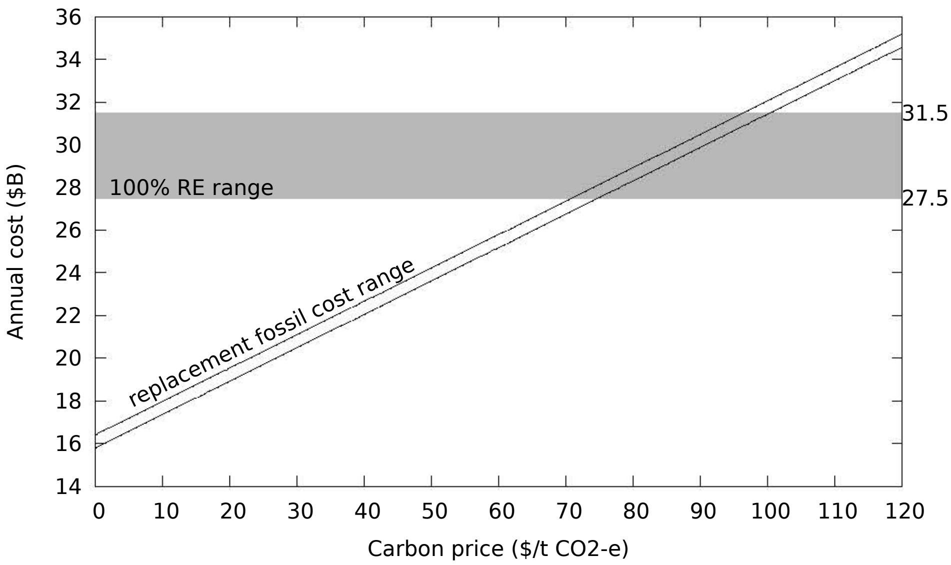

Figure 6.8: Annual costs for replacement fossil and renewable generating systems in 2030 as a function of carbon price (10% discount rate). Transmission costs excluded.

international market. The implication of higher fuel prices for the fossil-fuelled generation fleet is that operating costs will be higher and a lower carbon price will be required to make the renewable electricity system more attractive.

Figure 6.9 shows the expected Australian carbon price to 2050 as modelled by the Australian Treasury (2011) in its 550 parts per million scenario. The lateral bands in the figure indicate the range of carbon price thresholds above which the 100% renewable electricity system is lower cost than the replacement fleet. The range of threshold values is due to uncertainty in the projected technology costs in 2030. These carbon prices are expected to prevail in the years 2029–2034 (5% discount rate) and 2035–2043 (10% discount rate). It was decided in 2012 to link the Australian emissions trading system (ETS) with the European Union (EU) ETS. Due to depressed carbon permit prices in the EU, the future trajectory of carbon prices is now less certain. The IEA 450 parts per million scenario, by contrast, estimates much higher carbon prices to achieve effective action on climate change: $120 in 2035 compared with $74 (2012 $) in the Australian Treasury (2011) modelling.

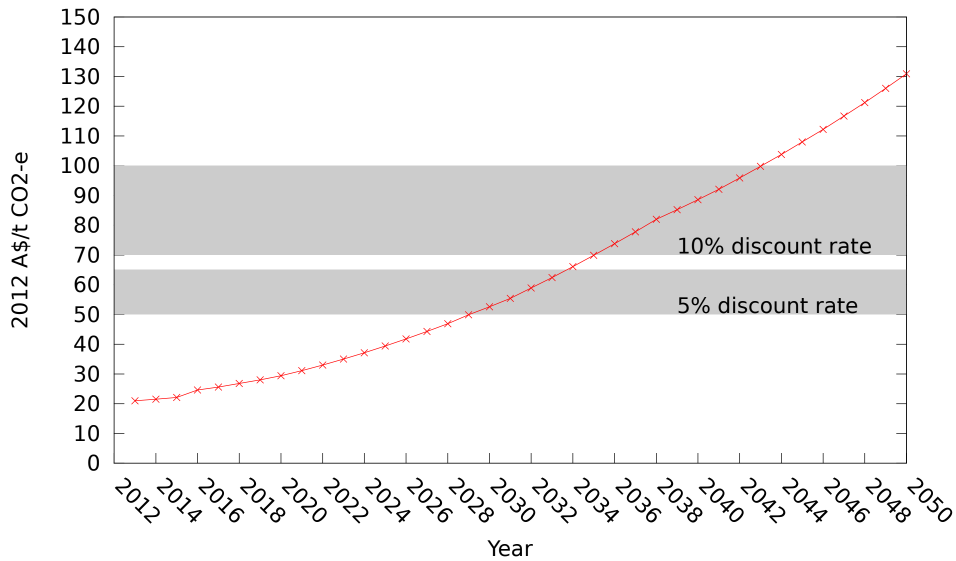

Figure 6.9: Trend in modelled Australian carbon price (in 2012 A$) with bands showing the expected range of years when the carbon price is high enough to equate the cost of the 100% renewable electricity system with the replacement fleet. Data: Australian Treasury (2011)

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6.4.3 International implications

In an international context, other regions of the world such as the Middle East and Africa have some similar characteristics to Australia: low price fossil fuels and an abundance of certain RE sources (eg, solar radiation). Despite the abundance of RE resources in Australia, the low price of fossil fuels makes the economic case for the 100% renewable system more challenging.

Some countries around the world, particularly in the EU, are well advanced on the path to renewable electricity supply. There are a number of features of the European situation which make direct comparisons with this study difficult: some that improve the economic case for 100% renewable electricity, and some that make it more difficult.

The more advanced deployment of RE in other countries would likely permit new generation to be built and operated at significantly lower cost than in Australia, at least initially. Countries with high dependence on imported fossil fuels pay a much higher price for power station fuel. This also improves the economic case for 100% renewable electricity.

There are two aspects which may make the economic case more difficult in regions outside Australia. Australia has a highly emissions intensive generating fleet that is heavily penalised by a rising carbon price. Few other electricity industries in the world are so carbon intensive and may therefore require higher carbon prices to reach the same cross-over point where a 100% renewable electricity system is the lower cost option. Furthermore, some RE sources (eg, solar radiation) are abundant in Australia and not matched in many other populated parts of the world. This difference in resource availability leads to higher generating costs in countries with poorer resource availability and a more difficult economic case for 100% renewable electricity.

Finally, the requirement for extensive transmission lines is unlikely to cause as much community opposition in Australia as it does in Europe and the United States due to the low population density.

6.5 Chapter summary

By developing and using a computationally efficient technique, a 100% renewable electricity generating system has been cost optimised over a wide geographic area, and a range of generating technologies, capacities and locations that meet reliability and sustainability criteria. Simulating with weather and demand data for the year 2010, a generating mix that is dominated by wind power, with smaller contributions from PV and CST, can meet 2010 electricity demand while maintaining the NEM reliability standard, limiting hydroelectricity generation subject to rainfall, and limiting the consumption of bioenergy.

Depending on the choice of discount rate, the 100% renewable system is cheaper on an annualised basis than a replacement fleet with a carbon price in the range of \$50–65 (5% discount rate) and \$70–100 (10% discount rate). Despite these conservative discount rates, the range of carbon prices that raise the cost of the replacement fossil-fuelled fleet above that of the 100% RE system appear modest, and below those carbon prices that appear to be required in order to effectively address climate change out to 2050. This range of carbon prices has been projected to prevail between 2029 and 2043, with the uncertainty predominately due to uncertainty in long-term carbon prices and the future cost of RE technologies. The prospect that a 100% renewable electricity system will be less costly than a renewed fossil-fuelled replacement fleet in the medium term poses some interesting policy questions about planning the construction of long-lived energy generation and infrastructure assets.

The reference scenario in this chapter provides a useful benchmark to evaluate the cost of 100% renewable electricity scenarios. However, the reference scenario does not deliver the emission reductions necessary to effectively address climate change. It can not be considered a realistic response to the need for low emissions electricity industries in Australia and elsewhere in the world. Three fossil fuel scenarios based on gas-fired and coal-fired electricity with carbon capture and storage (CCS) are considered in the next chapter.

Chapter 7

Fossil fuel scenarios

7.1 Introduction

In this chapter, the cost estimates of the scenarios for 100% renewable electricity presented in the previous chapter are compared against a number of alternative options available to policy makers: greater use of efficient gas-fired generation, and the use of carbon capture and storage (CCS). Nuclear power is not examined as it is prohibited in Australia under the Commonwealth Environment Protection and Biodiversity Conservation Act 1999. The key question being addressed is how these alternative scenarios compare with the 100% renewable electricity scenario and whether they are likely to be significantly lower cost. Indeed, is it worth either deploying gas-fired generation with lower, but still substantial emissions, or waiting for immature CCS technologies to emerge at sufficient scale? The intent of this chapter is to help inform policy as governments develop strategies in the face of significant uncertainty about technology development and costs.

The national circumstances of Australia are somewhat unique for a developed country, as was mentioned in Chapter 2. The electricity sector has an ageing fleet of fossil-fuelled thermal generators and is highly emissions intensive by world standards (Garnaut 2011a; Ison et al. 2011). Yet, Australia has manifold low carbon electricity options including wind, solar, biomass, marine and geothermal energy (Geoscience Australia and ABARE 2010), and considerable aquifer storage for '70–450 years of emissions' at an injection rate exceeding current National Electricity

Market (NEM) annual emissions (Carbon Storage Taskforce 2009). If CCS cannot be developed rapidly to commercial scale, there will be no future for coal-fired electricity in a carbon constrained world. While some mature renewable energy (RE) technologies, namely wind power and photovoltaics (PV), have experienced rapid cost reductions in recent years, progress on scaling up and commercialising CCS has been poor (International Energy Agency 2013).

The Australian Government presently has one main policy to promote utility-scale renewable electricity: a tradeable certificate scheme to reach 45 TWh per year of renewable generation by 2020, or 20% of generation forecast at the outset[1]. There is now an active discussion in Australia about long-term future energy scenarios and appropriate policies to enable the necessary electricity industry transition. The Australian Energy Technology Assessment (AETA) extensively examines the current and projected costs of 40 electricity generation options in Australian conditions including renewable, fossil and nuclear technologies; not all are commercially available today. Where technologies are not yet commercially available, the report estimates when they will become so. Although some cost figures in the report are disputed, the AETA has found wide use as a consistent basis for modelling by universities, government and industry researchers.

A body of previous research has examined the technical and economic feasibility of operating the NEM completely from RE sources, leading to zero operational emissions. Scenarios have been developed by the Australian Energy Market Operator (AEMO 2013a), by environmental research organisation Beyond Zero Emissions (Wright and Hearps 2010), and in this thesis. In evaluating the cost of a 100% renewable electricity scenario, it is necessary to compare with other future scenarios produced by a consistent method. A criticism of the AEMO (2013a) study has been that no reference scenario is provided to put the costs into context with alternative scenarios that can equally fulfill climate protection objectives (Riesz et al. 2013).

In this chapter, three lower carbon scenarios are considered for the NEM based on the estimated least cost mix to meet actual demand in 2010 of:

[1] The 45 TWh target now equates to approximately 25% of forecast generation in 2020.

(i) conventional combined cycle gas turbines (CCGTs) and open cycle gas turbines (OCGTs);

(ii) CCS-equipped coal plant and non-CCS OCGTs; and

(iii) CCS-equipped CCGTs and non-CCS OCGTs.

For these scenarios, a criterion used to select technologies for the 100% renewable electricity scenarios is relaxed: that the technologies be currently commercially available, although 2030 cost estimates are used. Scenario (i) above employs commercially available technology, but scenarios (ii) and (iii) do not.

The chapter is organised as follows. The current status of CCS, particularly in Australia, is given in Section 7.2. Section 7.3 describes each of the fossil fuel scenarios. Section 7.4 outlines sources of data used in the simulations. Section 7.5 documents the results for each of the scenarios. Section 7.6 discusses the implications of the findings.

7.2 Status of carbon capture and storage

Like other emerging energy technologies, CCS faces challenges due to competition from other lower carbon sources (eg, unconventional gas and wind power), a lack of ambition in climate policies, and a difficult policy environment. The International Energy Agency (2013) reports that there are 13 large-scale CCS demonstration projects operating or under construction world-wide. The majority of these projects are capturing, or will capture, emissions from gas processing facilities, not power stations. Several integrated CCS power generation projects are operational or under construction, capturing a small fraction of total plant emissions.

In its two degree scenario (2DS), the International Energy Agency (IEA) projected that around 65% of all coal-fired generation world-wide in 2050 would be equipped with CCS. Some pilot projects have been cancelled in recent years, causing a large shortfall in the annual rate of CO_2 expected to be sequestered by 2012: 65 Mt CO_2 per year as against 260 Mt CO_2 per year in the 2DS. The

International Energy Agency (2013) has expressed concern that, 'To deploy CCS on the scale and timeline outlined in the 2DS, policy makers will need to take immediate actions to enable and, further, to actively encourage private investment in CCS' and that, 'CCS must be developed and demonstrated rapidly if it is to be deployed after 2020 at a scale sufficient to achieve the 2DS'. Currently, there are no coal-fired power stations demonstrating CCS at commercial scale (International Energy Agency 2013). At current rates of progress, it appears difficult to achieve this level of deployment by 2050.

In Australia, there has been an expectation by government and industry that CCS will play an important role in decarbonising the emissions intensive electricity sector and, ultimately, securing the future of thermal coal exports by transferring CCS technology to trading partners (Gray 2013; Garnaut 2011c). The Australian Government has been a strong supporter of CCS through a number of research and development programs, demonstration programs, and a national CCS roadmap. Australia established the non-profit Global Carbon Capture and Storage Institute in 2009. Four coal-fired power stations in the NEM are trialling small pilot post-combustion capture units and one oxy-fuel combustion pilot is underway (CRC for Greenhouse Gas Technologies 2013; CSIRO 2012). Australia does not have specific financial incentives for operating CCS-equipped power plants. The International Energy Agency (2013) lists the United Kingdom as the only country proposing incentives to promote CCS beyond demonstration phase through feed-in tariffs, a floor on carbon prices and a minimum standard on the emissions intensity of new power stations (International Energy Agency 2013).

As a result of pressures in the 2013-14 Commonwealth Budget, the Australian Government reduced funding to the main Carbon Capture and Storage Flagships program by $500 million over the next three years (Australian Government 2013). While this may not indicate a crisis of confidence in the ability to commercialise CCS, this cut to research and development programs is problematic given the slow progress of CCS development and deployment.

7.3 Fossil fuel scenarios

This section describes each of the fossil fuel scenarios. Note that none of these 'lower carbon' fossil fuel scenarios yields an electricity supply system with zero operational emissions. This can notionally only be achieved by the 100% renewable electricity scenario (abbreviated to 'RE100' in this chapter). None of the scenarios account for the lifecycle emissions of the generation technologies considered, or the emissions associated with fossil fuel extraction and transportation. Four features are common to all scenarios:

1. capital costs projections for 2030 are taken at the low end of the range for each technology as reported in the AETA (Bureau of Resources and Energy Economics 2012a) with a 5% discount rate;

2. transmission requirements are not modelled (further elaboration is given in Section 7.6.1);

3. OCGTs in the scenarios do not capture any CO_2 emissions because there has been no development of capture units for OCGTs. These generating units are typically operated at a low capacity factor that does not justify the capital expense of capture equipment (Florin 2013); and

4. to reduce the number of simulated generators and speed up the simulation runs, each fossil-fuelled plant technology is represented by one simulated generator with a large capacity. That is, regional variations in fossil-fuelled plant efficiency or fuel costs are not considered.

Baseline parameter values for all scenarios are given in Table 7.1 and discussed in more detail in Section 7.4. If a parameter is not varied for sensitivity testing, its value is taken from Table 7.1.

Black coal price	\$1.86	/GJ
Gas price	\$11	/GJ
Carbon price	\$56	/t CO_2
CO_2 storage cost	\$27	/t CO_2
Emissions rate of coal plant	0.8	t/MWh
Emissions rate of OCGT plant	0.7	t/MWh
Emissions rate of CCGT plant	0.4	t/MWh
CCS post-combustion capture rate	85	%
Discount rate	5	%

Table 7.1: Baseline parameter values chosen for scenarios. Costs shown are projections for 2030 in current dollars.

7.3.1 CCGT scenario

In the CCGT scenario, the generation fleet consists of conventional CCGTs plant, the existing NEM hydroelectric power stations[2], and OCGT plant fuelled by gas. Generation is dispatched in that order. A carbon price is paid on all emissions as none are captured.

The CCGT scenario has some appealing characteristics: it relies on proven and commercially available technology, it could be constructed quickly, it has lower capital costs than coal-fired plant, and it has the lowest emissions of all commercially available fossil-fuelled technologies (approximately 400 g CO_2 per kWh). It has been noted by Viebahn et al. (2007) that a CCGT plant produces 'only 45% more emissions (400 g CO_2 per kWh) than the worst [performing] power plant with CCS (pulverised hard coal with 274 g CO_2 per kWh)' when the additional emissions associated with capture (88% capture rate), compression, transportation and storage are included. If the emissions reductions associated with heat recovered from a combined heat and power CCGT are included, CCGT has a similar emissions intensity to black coal with CCS.

The CCGT scenario is consistent with some of the approaches of the International Energy Agency (2012b) four degree scenario. That is, switching from coal to lower carbon fuels and dramatically improving the conversion efficiency of thermal plant. The main disadvantages of this scenario are that it does not achieve the

[2]7.1 GW total capacity including 2.2 GW of pumped storage hydro stations. Long-term average generation is 12 TWh per year.

emissions reduction required to meet the 2050 target and it produces a generation fleet almost completely dependent on a single fuel that has considerable future price risk.

7.3.2 Coal CCS scenario

In the coal CCS scenario, the generation fleet consists of supercritical pulverised black coal plant fitted with post-combustion capture and storage, existing hydro, and OCGT plant fuelled by gas. Generators are dispatched in that order. CO_2 transportation and storage costs, hereinafter abbreviated to CO_2 storage costs, are applied to each tonne of captured emissions and a carbon price is paid on emissions not captured by the coal plant and OCGTs.

Although other CCS technologies are under development, namely pre-combustion capture through integrated gasification combined cycle (IGCC) plants, and oxy-fuel combustion, the analysis has been limited to post-combustion capture. This choice reflects the fact that coal-fired plant with post-combustion capture has the lowest projected capital cost in 2030 of the three CCS technologies surveyed in the AETA report.

7.3.3 CCGT-CCS scenario

The CCGT-CCS scenario is identical to the CCGT scenario, except that post-combustion CCS is fitted to the CCGT plant. A carbon price is paid on non-captured emissions from the CCGT plant and all emissions from the OCGT plant. CO_2 storage costs are applied to captured emissions.

7.3.4 Comparison with optimal mix

The traditional method of finding the economically optimal mix for conventional generation uses a characteristic load duration curve. Equations 7.1 and 7.2 calculate the number of load hours met by intermediate plant with greater operational flexibility and higher running costs than 'baseload' plant, and by peak load plant with the highest flexibility and running costs (Weyman-Jones 1986). Figure 7.1

shows the 2010 system-wide load duration curve with arbitrary set points h_i and h_p for illustration. The plant serving baseload notionally operates every hour of the year, subject to availability. In these equations, c is the plant capital cost and r is the running cost. Subscripts b, i and p represent baseload, intermediate load and peak load, respectively.

$$c_i + h_p r_i = c_p + h_p r_p \tag{7.1}$$

$$c_b + h_i r_b = c_i + h_i r_i \tag{7.2}$$

For consistency, the same simulation tool was used to determine the least cost plant mix for the fossil fuel scenarios. The advantage of this approach is that it is easy to develop new scenarios with different generation mixes and, through multiple runs, test the sensitivity of some parameters. The genetic algorithm (GA) can be expected to find the same mix as the analytic technique and this was verified using a simple scenario of one coal-fired plant, one CCGT for intermediate load, and one OCGT for peak load.

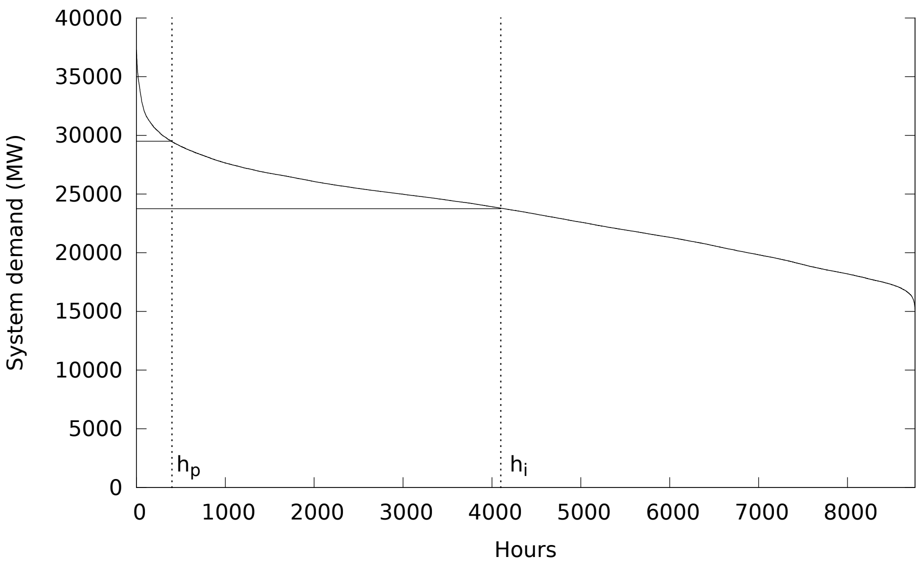


Figure 7.1: System-wide load duration curve for the NEM in 2010 with h_p and h_i chosen arbitrarily for illustration. h_p and h_i is the number of hours of peaking and intermediate plant operation, respectively. Data source: AEMO.

7.4 Cost and performance data

Projected technology costs for 2030 are taken from AETA (Bureau of Resources and Energy Economics 2012a) and are listed in Table 7.3. Note that CCS plant have lower thermal efficiency and higher variable costs than their non-CCS counterparts due to the auxiliary load of CO_2 capture and compression. The following section explains the other data used in the scenarios.

7.4.1 CO_2 transportation and storage costs

As well as the capital cost of carbon capture equipment at the power station, CCS involves the transportation of compressed CO_2 via pipelines to suitable storage sites. Allinson et al. (2009) conducted a first-pass scoping study for CO_2 transportation and storage potential in Australia based on industry-supplied costs and resource data. To date, it remains the only comprehensive analysis of the costs of CO_2 transportation and storage in Australia.

Allinson et al. (2009) produced central estimates of the costs for CO_2 transportation and storage, excluding the cost of capture, compression of the pure CO_2 stream to 8 MPa, and transportation to the nearest node in the pipeline network. The transportation network assumes that emissions from an individual power station or industrial process are carried by pipeline to a regional hub, where they are further compressed for long-distance transportation to a reservoir. There is significant variation in the costs for different source and sink site combinations around Australia. The costs are still highly uncertain, but are dependent on the CO_2 injection rate, the storage reservoir characteristics and geographic location. The most sensitive factor in the cost of CO_2 transportation and storage is the reservoir characteristics. Some aspects of the costings are more certain, as CO_2 transportation and storage utilises relatively mature gas handling technologies.

CO_2 transportation and storage is capital intensive, requiring pipelines, compressors and reservoir preparation. A cost per tonne of CO_2 avoided was calculated by Allinson et al. (2009) using the present value of project expenditure over 25 years (using a 12% discount rate) divided by the present value of emissions that

Region	2009 \$ (12% d.r.)	2009 \$ (5% d.r.)	2013 \$ (5% d.r.)
North Queensland	41	25	28
South Queensland	23	14	15
New South Wales	72	44	48
Victoria	22	15	17
Mean	40	24	27

Table 7.2: CO_2 storage costs by region. Costs in 2009 dollars using a 12% discount rate (d.r.) are shown alongside adjusted costs using a 5% discount rate. Third column shows 2013 dollars using a 2.5% per year inflation rate. Data derived from Allinson et al. (2009).

could be sequestered over the 25 years. For each region of the NEM, the lowest cost combination of source and sink sites (Table 7.2) have been chosen. To place these costs on equivalent terms to other costs in the scenarios, the costs were re-calculated using a 5% discount rate (central column, Table 7.2) and adjusted them to current dollars for regions of interest (rightmost column, Table 7.2). Costs were escalated at an inflation rate of 2.5% per year.

7.4.2 Other data

In this section, each of the other values in Table 7.1 are explained.

- The black coal price is assigned a single value of $1.86 per GJ. This represents an average projected 2030 price for black coal across the NEM regions (Bureau of Resources and Energy Economics 2012a). Some coal mines supply fuel to nearby power stations as they have no economic means to move coal to export facilities. Presently, NEM coal-fired power stations are somewhat insulated from international coal prices.

- Gas prices in the Australian domestic gas market have traditionally been low by world standards. The present development of export terminals along the east coast of Australia will give domestic gas producers access to international markets and this is increasing gas prices in the domestic market from around $3 per GJ to as high as $9 per GJ (Grudnoff 2013). The Bureau of Resources and Energy Economics (2012b) highlights the wide variation in long-term gas price projections between market analysts and even the same analysts over time. From 2010 to 2012, one analyst repeatedly increased their projection of eastern state gas prices in 2030 from $7.50 (2010 dollars) per GJ to $11–12 per GJ depending on the region (2013 dollars). A baseline projected 2030 gas price of $11 per GJ has been assumed with a number of different prices tested from $3 to $15 per GJ.

- The baseline carbon price of $56 per tonne CO_2 is the projected price by the Australian Treasury (2011) in the Australian emissions trading scheme in 2030, adjusted to current dollars. This estimate is based on a conservative core policy scenario which assumes a 550 parts per million (ppm) stabilisation target. The projected price of carbon for the high price scenario, based on a 450 ppm stabilisation target, is $120 per tonne CO_2, adjusted to current dollars. The IEA estimates similar carbon prices for an appropriate response to a 450 ppm target (eg, US$120 in 2035). A wide range of carbon prices for 2030 are therefore analysed in the simulations from $20 to $140 per tonne CO_2.

- A single average cost of CO_2 storage is used from regions around the NEM (Table 7.2). Due to the wide range of values and uncertainty discussed in Section 7.4.1, this parameter is varied in the simulations from $20 to $100 per tonne CO_2. The NEM-wide average of $27 is situated in the lower end of the range as the lowest cost source and sink site combinations were chosen in each region.

- The gross emission rates of the simulated coal, OCGT and CCGT plant is 0.8, 0.7 and 0.4 tonnes CO_2 per MWh (sent out), respectively. For CCS variants, a fraction of this CO_2 is captured and the net emissions are released.

- The post-combustion capture rate is estimated at 85%. This is a slightly conservative figure, as capture rates as high as 90% have been reported for small-scale pilot projects (CSIRO 2012).

- Choosing a discount rate is contentious and only one discount rate (5%)

Technology	Heat rate (GJ/MWh)	Capital cost ($/kW)	Fixed O&M ($/kW/yr)	Variable O&M ($/MWh)
CCGT	6.92	1015	12	5
CCGT w/ CCS	8.35	2095	20	11
CST		5622	65	23
OCGT (fossil gas)	11.61	694	5	12
OCGT (biofuel)	11.61	694	5	92
On-shore wind		1701	40	14
PV		1482	25	0
Supercritical black coal	8.57	2947	59	8
Supercritical black coal w/ CCS	11.46	4453	107	18

Table 7.3: Projected costs (low end of range) in 2030 for selected generating technologies (2012 dollars). Consistent with AETA methodology, operating and maintenance costs are inflated by 17.1% over the period. Source: Bureau of Resources and Energy Economics (2012a)

has been used in this work to keep the scope manageable given all of the other uncertainties being considered. When modelling a single year, as was done, the discount rate has only the effect of altering the magnitude of annualised capital repayments. The fact that fuel and operating costs in subsequent years will be discounted at different rates is of no consequence when modelling one year.

7.5 Results and analyses

7.5.1 100% renewable electricity scenario

As a reminder for the reader, the least cost estimate of the RE100 scenario (low cost, 5% discount rate case) in Chapter 6 was $19.6 billion per year.

7.5.2 Coal CCS scenario

Figure 7.2 shows 30 annualised least cost solutions for the coal CCS scenario under a range of different CCS plant capital costs and CO_2 storage costs. It is not readily apparent from the near-linear increase in annual costs seen in Figure

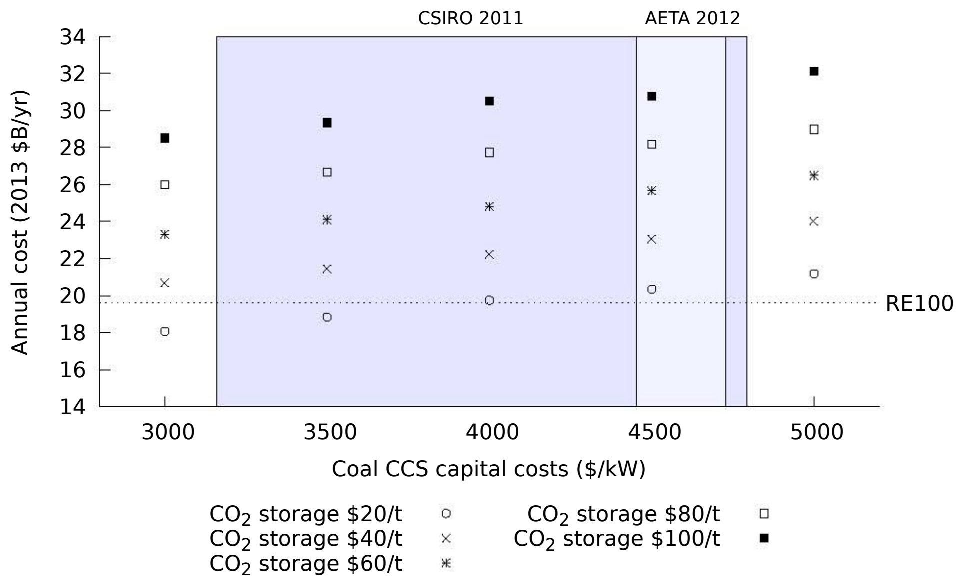


Figure 7.2: Sensitivity of annual costs to coal CCS capital costs ($/kW) and CO_2 storage costs ($ per tonne CO_2) in coal CCS scenario. Shaded regions show the range of estimates from CSIRO (Hayward et al. 2011) and the AETA (Bureau of Resources and Energy Economics 2012a).

7.2, but changing variables in the simulations such as coal CCS capital cost, CO_2 storage cost and carbon price changes the lowest cost generation mix. When CO_2 storage costs are higher and/or carbon prices are lower, it becomes economic to move a greater share of generation to the OCGT plant without emissions capture and to incur the cost of emissions.

The shaded regions of the plot show the range of plant capital cost estimates from CSIRO (Hayward et al. 2011) and the AETA (Bureau of Resources and Energy Economics 2012a). Carbon and coal prices are held constant. Of the combinations tested, the only cases that produce a lower annual cost than the RE100 scenario are those with a CO_2 storage cost of $20 per tonne CO_2 *and* plant capital cost below $4000 per kW. Every case where the cost of CO_2 storage is $40 per tonne or more is uneconomic compared to the RE100 scenario.

The sensitivity of the coal CCS scenario to CO_2 storage costs and the carbon price is shown in Figure 7.3. The plant capital cost and coal price are held constant. A range of carbon prices ($20 to $140 per tonne CO_2) and a range of CO_2 storage costs ($20 to $100 per tonne CO_2) were tested. The principal finding is that the RE100 scenario is lower cost than the coal CCS scenario in all of the cases tested.

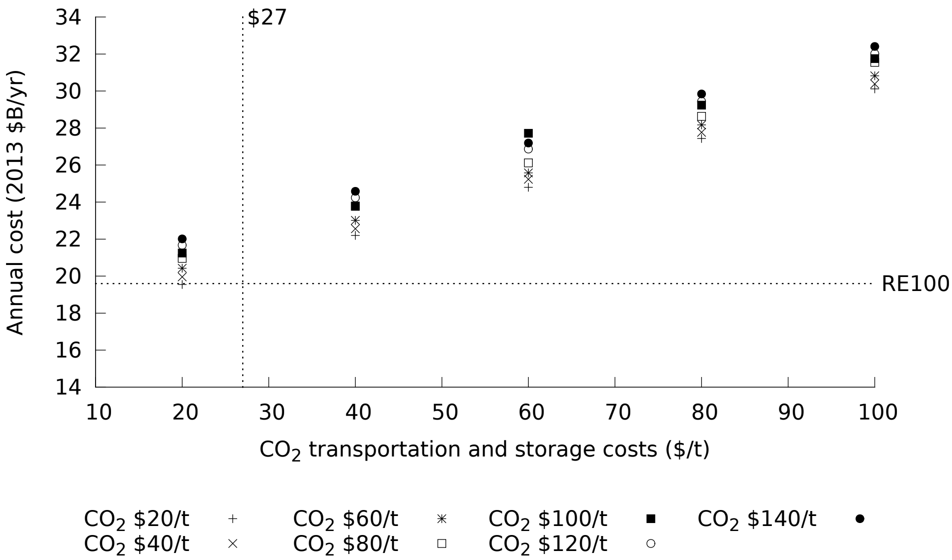


Figure 7.3: Sensitivity of annual costs to carbon price and CO_2 storage costs ($ per tonne CO_2) in coal CCS scenario. Vertical line is the baseline CO_2 storage cost from Table 7.1.

Within the range of CO_2 storage costs tested, there is not much sensitivity to the carbon price, as most of the emissions in the coal CCS scenario are sequestered. Some emissions from the coal-fired plant are not captured, in addition to emissions from the OCGT peak load plant.

Figure 7.4 shows that the coal CCS scenario would reduce NEM emissions to below the level required to meet the 2050 target. If demand in 2030 is significantly greater than in 2010, emissions will be higher and could exceed the 2050 target. As noted earlier, cuts greater than 80% may be required in the electricity sector if other sectors are more difficult to decarbonise.

7.5.3 CCGT and CCGT-CCS scenarios

Figure 7.5 shows the CCGT-CCS scenarios for the carbon prices at each end of the range: $20 per tonne CO_2 and $140 per tonne CO_2, alongside the equivalent coal CCS cases for comparison. The coal CCS scenario is more sensitive to increased CO_2 storage costs due to the volume of emissions produced. The much higher cost of gas ($11 per GJ) over coal ($1.86 per GJ) means that the coal CCS scenario has a lower annual cost, despite the higher volume of emissions, until the CO_2

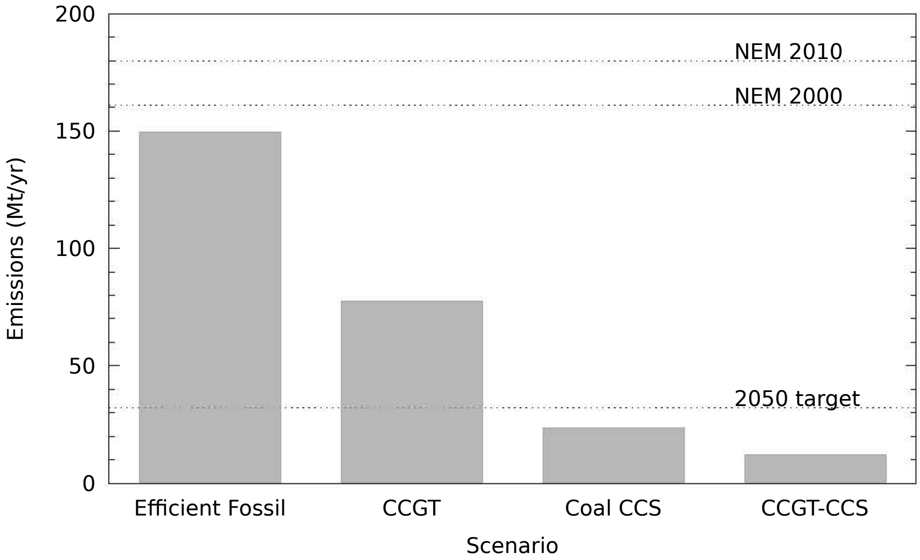


Figure 7.4: Annual emissions from different fossil fuel scenarios for electricity generation. Horizontal lines show emissions produced from NEM operations in the year 2000 and 2010. The level required to reduce emissions by 80% is also shown.

storage cost exceeds \$100 per tonne. The cost advantage of coal CCS diminishes and the four scenarios approximately converge at a CO_2 storage cost of around \$110 per tonne. At this point, the CCGT-CCS scenario starts to become lower cost than coal CCS as the higher thermal efficiency of the combined cycle plant reduces the volume of captured emissions. At realistic costs for gas, carbon, and CO_2 storage, CCGT-CCS is uneconomic compared with the RE100 scenario.

Figure 7.6 shows the effect of gas and carbon prices on the annual cost of the CCGT and CCGT-CCS scenarios. CO_2 storage costs are held constant. The CCGT scenarios perform well due to their high thermal efficiency and comparatively lower emissions. The annual cost of the CCGT scenario (without CCS) with a \$9 per GJ gas price exceeds the RE100 scenario at a carbon price of \$60 per tonne CO_2. Provided that the gas price and/or the carbon price is low, the CCGT scenario is a lower cost option than the RE100 scenario. Note, however, that these scenarios still produce over 77 Mt of CO_2 per year (Figure 7.4), far higher than the level required for Australia to meet its 2050 target. The CCGT scenario is more accurately described as 'medium carbon'.

Even if there is no carbon price, a gas price of \$12 per GJ would enable the RE100

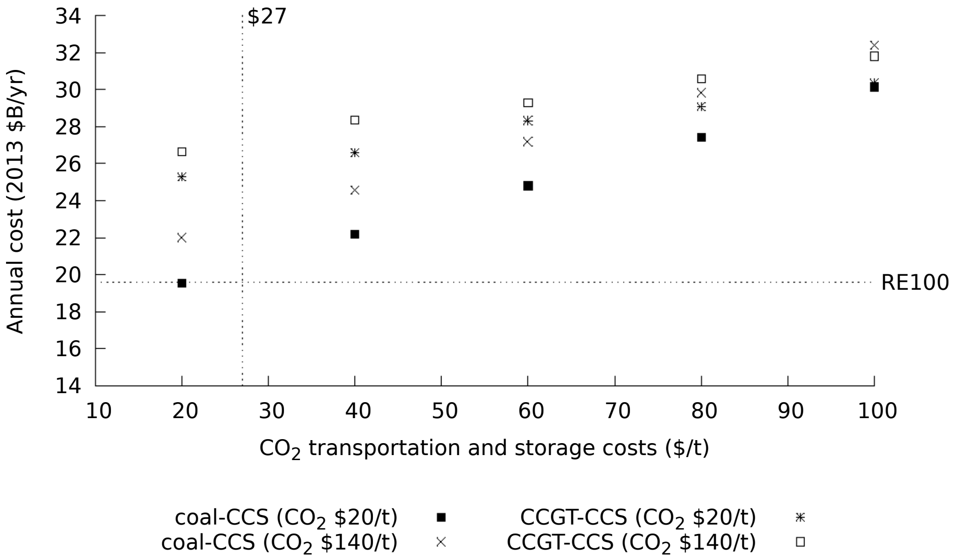


Figure 7.5: Sensitivity of annual costs to CO_2 storage costs ($ per tonne CO_2) for different scenario and carbon price combinations. Vertical line is the baseline CO_2 storage cost from Table 7.1. Plant capital costs, coal price and gas price are held at baseline values in Table 7.1.

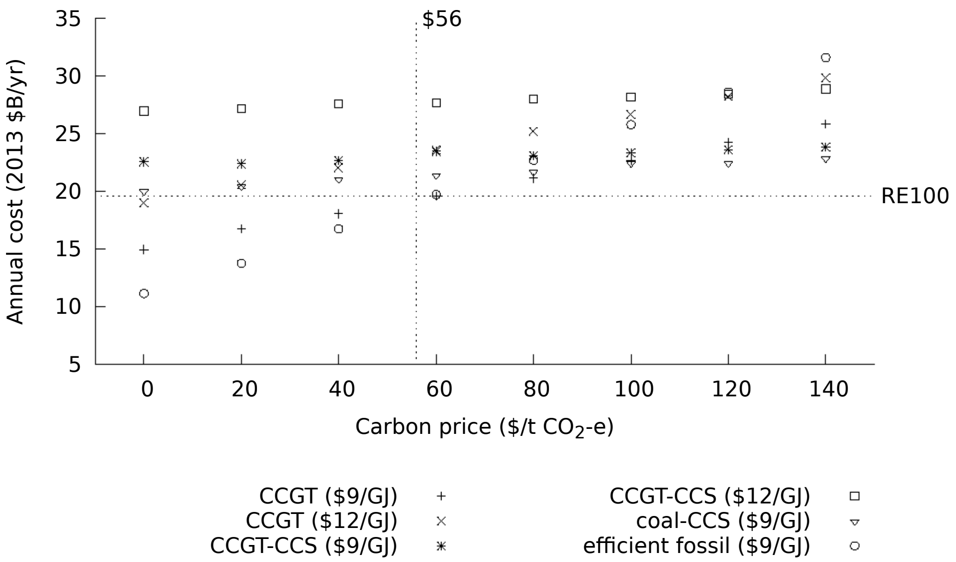


Figure 7.6: Sensitivity of annual cost to carbon price ($ per tonne CO_2) and gas prices ($ per GJ). Vertical line is the baseline carbon price from Table 7.1.

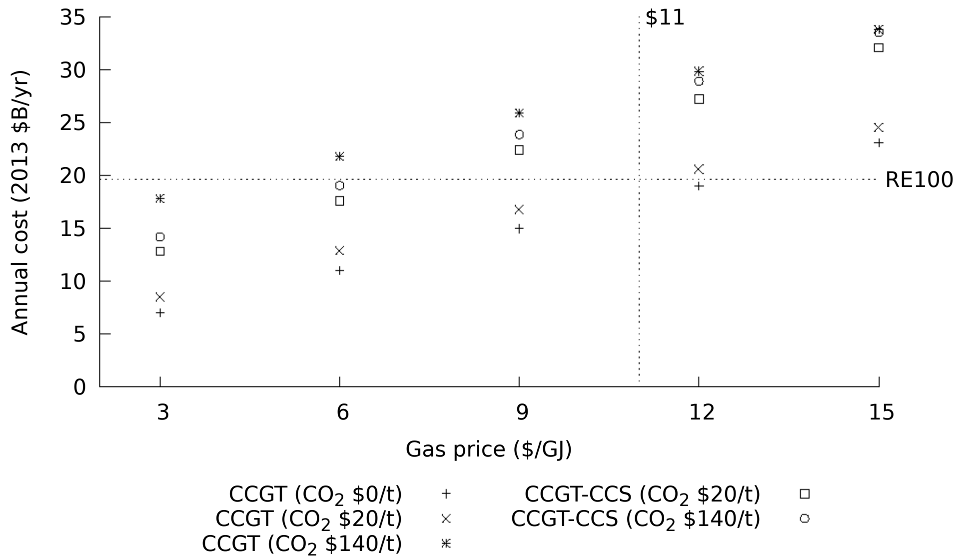


Figure 7.7: Sensitivity of annual cost to gas price ($ per GJ) in various scenarios. Vertical line is the baseline gas price from Table 7.1.

scenario to compete economically with the CCGT scenario. With no emissions being captured, the cost of the CCGT scenario rises sharply with an escalating carbon price. The CCGT-CCS scenarios are much more costly than the RE100 scenario unless the gas price is lower than $9 per GJ. At a carbon price of $60 per tonne[3] none of the fossil fuel scenarios has a lower annual cost than the RE100 scenario.

Figure 7.7 shows the effect of carbon price and gas price on annual cost in the CCGT and CCGT-CCS scenarios, holding CO_2 storage cost constant. The CCGT scenario with a nil carbon price is included as a limiting case. At a gas price of $3 per GJ, all the fossil fuel scenarios are lower cost than the RE100 scenario. At $6 per GJ, all cases except CCGT with a carbon price of $140 per tonne CO_2 are lower cost than the RE100 scenario. At $9 per GJ, the CCGT scenarios are lower cost than the RE100 scenario provided that the carbon price is low. The CCGT-CCS scenarios are higher cost due to the higher capital cost of CCS-equipped plant. At $12 per GJ, the only scenario that is lower cost than the RE100 scenario is CCGT with no carbon price. At $15 per GJ, the CCGT and CCGT-CCS scenarios have a higher annual cost than the RE100 scenario in all cases.

[3]Refer to all points at 60 on the *x* axis in Figure 7.6.

In summary, the three fossil fuel scenarios have different sensitivity to coal prices, gas prices, carbon prices and CO_2 storage costs. Just as the annual cost of operating a fossil-fuelled power station is influenced by the cost of fuel, the economics of a CCS-equipped power station are influenced by plant thermal efficiency, fuel cost, the price of emissions permits, and the cost of transporting and storing compressed CO_2. A less thermally efficient power station produces more emissions and is more sensitive to CO_2 storage costs. In a complete generating system, the carbon price and CO_2 storage cost variables induce opposing effects in the least cost generating system. If one variable increases relative to the other, then the least cost mix changes. For example, in the coal CCS scenario with coal CCS plant, existing hydro and OCGTs, a prohibitively high CO_2 storage cost produces the effect of the genetic algorithm shifting *all* generation to OCGTs such that the lowest cost solution becomes independent of the CO_2 storage cost.

7.6 Discussion

Testing the three fossil fuel scenarios (coal CCS, CCGT and CCGT-CCS) under a range of plausible parameter values, the majority of cases do not compete economically with the RE100 scenario. The baseline values in Table 7.1 are believed to be reasonable estimates for the year 2030 given the inherent uncertainty and underlying drivers of carbon prices, gas prices, technology capital costs, and CO_2 storage costs. In some limited circumstances, the fossil fuel scenarios can be lower cost than the RE100 scenario, but this requires multiple conditions (eg, a low gas price and low CO_2 storage costs).

7.6.1 Limitations

There are two principal limitations to the simulations described in this chapter. First, the fossil fuel scenarios deliver a higher share of fossil-fuelled generation than is likely in practice. Existing hydro is included in the scenarios, but present wind power and wind power anticipated by 2020 is not. By 2020, Australia is expected to source around 25% of its electricity from RE under the expanded

Renewable Energy Target (eRET), predominantly from wind power and hydroelectricity. Lund and Mathiesen (2012) have modelled the integration of CCS into high penetration renewable systems by introducing a single CCS-equipped combined heat and power plant into the Climate Plan 2050 scenario for Denmark. They observed that unless the CCS plant is dispatched out of order (ie, ahead of lower marginal cost generation), the capacity factor of the CCS plant is too low to be economic. An assumption has been made that including wind power would increase the cost of the three fossil fuel scenarios when the carbon price and CO_2 storage costs are low. The cost of these fossil fuel scenarios therefore represents a lower bound.

Second, the transmission network is not modelled. In Chapter 6, the transmission requirements to achieve hour-by-hour balancing between the five NEM regions were estimated to have an annual cost of $1.6 billion per year (5% discount rate over a 50 year economic lifetime). This cost is not particularly onerous when considered in the context of the total cost of the RE100 scenario ($19.6 billion per year). The transmission requirements for the fossil fuel scenarios are not significantly different to the present transmission network, but the requirements for the RE100 scenario will increase the costs as indicated. For simplicity, the simulations are of generation only.

7.6.2 Implications

The CCGT scenario provides useful insight into what is possible using lower carbon, commercially available fossil-fuelled plant. The CCGT scenario is sensitive to gas prices and, to a lesser degree, carbon prices. With emissions over 77 Mt per year, and well in excess of the 2050 target, it would have to be ruled out on environmental grounds. Generation portfolios based on large quantities of gas-firing require lower gas prices than are being faced in some gas markets today to compete economically with the RE100 scenario.

The transition from mostly coal-fired to mostly gas-fired generation has been presented as an assured opportunity for reducing electricity emissions by industry and some sections of government (Molyneaux et al. 2013). Gas is promoted as a transition fuel on the path to a completely decarbonised energy system – the so-called 'bridge to the future' (Aguilera and Aguilera 2012; Paltsev et al. 2011). For Australia, gas offers the advantages of being an abundant, domestically available fuel with lower carbon content than coal. There are concerns that fugitive methane emissions from unconventional gas extraction may negate any savings from using gas instead of coal (Jacobson et al. 2013), and this is an active area of research in Australia (Day et al. 2012; Grudnoff 2012).

Should CCS be developed at scale and in time to contribute to the decarbonisation of the electricity sector, on current projected costs for 2030, the scenarios based on CCS or gas-fired plant do not produce a result that is robustly cheaper than commercially available RE technologies. The CCS scenarios demonstrate policy risks, utilising technology that has not been proven at commercial scale and with uncertain costs. Simulations show that these fossil fuel scenarios are not low cost and have the disadvantage of being reliant on non-renewable fuels. The CCGT-CCS scenario produces the lowest CO_2 emissions of all three fossil-fuel scenarios, but with the highest cost on current projections. Coal CCS requires that CO_2 storage costs be minimised, particularly for power stations in New South Wales, which would require piping over long distance to the Cooper Basin in South Australia.

CSIRO (2012) quantifies the impact of CCS on generation costs for new black coal-fired plant, increasing costs from $55 per MWh to around $110 per MWh without considering carbon pricing. The eFuture scenario tool[4] from CSIRO produces similar results. AEMO (2013a) examined the impact on wholesale prices in its 100% renewables study and found that the two 2030 scenarios for 100% renewable electricity produce an average wholesale cost of $111 per MWh and $128 per MWh, depending on the input assumptions. While these figures cannot be compared directly, it suggests that the dominant alternatives to renewable electricity are not substantially lower cost.

It is assumed that gas prices in Australia will rise in the medium-term to approach prices in international markets. The results presented in this chapter are

[4]http://efuture.csiro.au

likely to be similar in countries where gas prices are already higher than faced in Australian domestic markets. Moreover, in countries with little domestic supply of coal and gas, these scenarios would lead to high dependence on imported fuel. It is possible that these scenarios would be ruled out in such countries on energy security grounds.

7.7 Chapter summary

None of the fossil fuel scenarios in this work achieves zero operational emissions as the RE100 scenario can. As decarbonisation takes place across the economy, it may become evident that very deep cuts in emissions are required in the electricity sector to compensate for lesser cuts in more challenging sectors.

It is possible to argue that publicly funded CCS research and development should continue. If CCS technology can be delivered in a timely and cost effective manner, it offers significant abatement potential and increases the set of available options. The International Energy Agency (2013) states, 'Delaying or abandoning CCS as a mitigation option in electricity generation will increase the investment required in electricity generation by 40% or more in the Energy Technology Perspectives 2012 2DS and may place untenable demands on other emissions reduction options.' The results suggest that without CCS, other low carbon electricity generation can be pursued at similar cost in the Australian context, at least.

Furthermore, the results suggest that it is not necessary to wait for CCS technologies to emerge. Policies pursuing very high penetrations of renewable electricity based on commercially available technology appear a reasonable option given the lower technology risks, lower investment risks, and the ability to reach zero operational emissions in the electricity sector.

Chapter 8

Improving the contribution of variable renewable sources

8.1 Introduction

An appreciation for the temporal and spatial characteristics of renewable energy sources such the wind or solar radiation is crucial for the successful integration of these energy sources into electricity system at high penetration. Resource characterisation exercises such as the two analyses presented in this chapter are valuable in deploying renewable energy generation economically, and to maintain high levels of reliability in the system.

Section 8.2 presents an analysis of the wind power contribution that can be achieved by exploiting differences in wind speeds across wide geographic areas of the National Electricity Market (NEM). In Section 8.3, the location, duration and frequency of low solar direct normal irradiance (DNI) events over the Australian continent are characterised. Protracted periods of very low DNI leads to a temporary loss of output from concentrating solar thermal (CST) power stations.

8.2 Siting wind farms to improve wind contribution

In geographic regions with high levels of insolation – such as south-west USA, Mexico, North Africa, the Middle East, north-west China, north-west India and

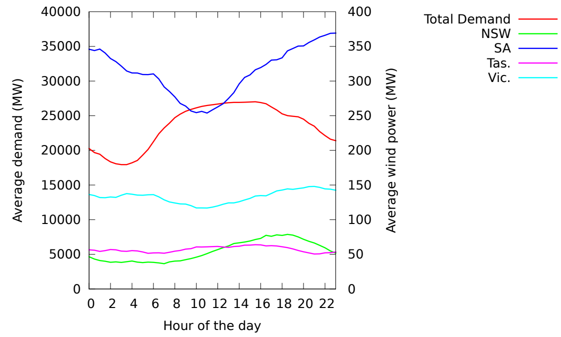
Australia – solar electricity, both CST and photovoltaic (PV), can together make the major contribution to electricity generation. In Chapter 5, the most challenging period for 100% renewable electricity in the NEM was found to be the evening peak demand periods in the winter months. On winter evenings following overcast days, wind speeds are low, solar energy has contributed less during the day due to the lower winter resource, and household activities such as electric cooking and space heating place high power demands on the grid. In the scenarios, demand is met during these events by a large capacity of gas turbines fuelled with bioenergy to provide dispatchable power (refer back to Figure 5.2).

In this section, the effect of relocating a proportion of wind energy from the existing wind farm locations in south-eastern Australia to other regions is considered. In the scenarios of 100% renewable electricity, addressing these periods by increasing the generating capacity of wind power in existing locations consequently produces many more periods of over-generation in high wind conditions. The placement of wind farms in alternative locations around the NEM is one approach to reduce the generating capacity of gas turbines and to reduce the quantity of bioenergy that they consume.

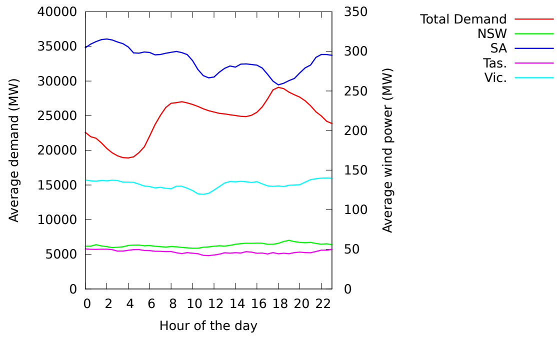
8.2.1 How could wind output improve?

Most of the wind power installed in the NEM in 2014 is located in South Australia and Victoria, predominantly in the same wind regime. Aggregate wind farm output in each NEM region can therefore fall to low levels. The reliably available wind capacity – the minimum capacity that can be expected to be available with high probability – can be achieved by dispersing wind farms. This observation is supported by earlier small studies in Australia (Carlin and Diesendorf 1983; Davy and Coppin 2003). This may require siting wind farms in regions that have overall lower yield, but are beneficial in the context of the entire system. Dispersing wind farms can reduce the requirement for other generation capacity such as biofuelled gas turbines, by reducing periods of under- and over-generation.

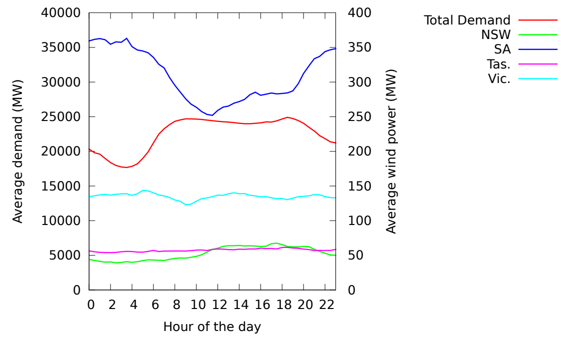
In addition to the present limited temporal and spatial diversity of wind power across the NEM, wind farms constructed in South Australian and Victoria to date



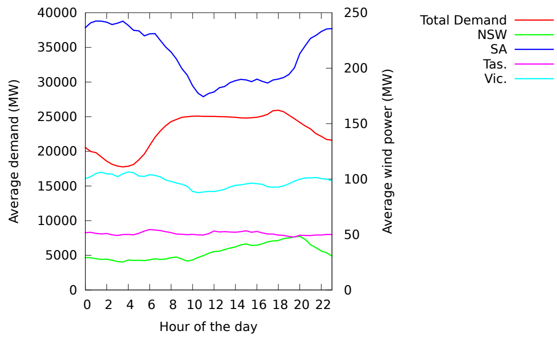
(a) Summer



(b) Winter



(c) Spring



(d) Autumn

Figure 8.1: Seasonal correlations between total demand (LHS) and aggregate wind power (RHS) in NEM regions with significant level of wind capacity

have been found to generate power with weak correlation with electricity demand. The small number of wind farms constructed in New South Wales (NSW) show better correlation. Figure 8.1 shows the correlation between regional aggregate wind power and total NEM demand in each season and NEM region[1]. In a system with a high proportion of wind generation and limited storage options, the potential to integrate much higher quantities of wind power is significantly improved if wind generation can coincide more closely with demand.

It was noted in Chapter 6 that wind power is projected to have one of the lowest levelised costs of energy (LCOEs) of the low carbon technologies available in 2030 and beyond (Bureau of Resources and Energy Economics 2012a). This is due to the maturity of wind power and continual improvements in the performance and reliability of wind turbines. It is therefore desirable if a substantial fraction of the

[1] Queensland is excluded as it has only 12 MW of installed wind capacity.

electricity demand can be met by this low cost source of generation.

At very high levels of wind power penetration, surplus generation events become more common. As generating capacity is further increased, capacity factors begin to decline as a greater proportion of the additional generation is curtailed. Curtailments and large wind power deficits can both be addressed by improving the coincidence between wind output and demand.

Coincidence between wind generation and demand can be improved through demand response measures. In the simulations, over-generation is handled by diverting surplus electricity into pumped storage hydro (PSH) plants and electric resistance heating of the thermal storage medium of CST plants. However, the opportunities for diverting surplus electricity are limited in the scenarios (eg, surplus wind power in summer has limited potential to heat CST thermal storage), and most surplus wind power is curtailed. One approach to curtailment being contemplated in some European scenarios is to divert surplus electricity to so-called 'power to gas', a chain of electrolysis and methanation processes to produce synthetic gas (German Federal Ministry of Technology and Economics 2010; Henning and Palzer 2014; Palzer and Henning 2014). The gas can be stored in conventional gas infrastructure and used for fuel in gas turbines during low wind or solar conditions.

On the supply side, the reliably available wind capacity can also be improved by dispersing wind farms. This is explored in the following sections.

8.2.2 Dispersing wind power in the scenarios

Synthetic wind data for a number of sites were produced using The Air Pollution Model (TAPM). TAPM is a meteorological air pollution model developed by CSIRO Marine and Atmospheric Research to model the spread of air pollution. Using terrain data and observed synoptic data for a given year, TAPM can model a number of meteorological variables at hourly resolution, at a range of spatial resolutions, and over a wide spatial area. Hourly 2010 wind speed data were produced for six sites, a mixture of coastal and inland locations over a range of latitudes (see Figure 8.2). They are Hallett in South Australia, Condoblin and

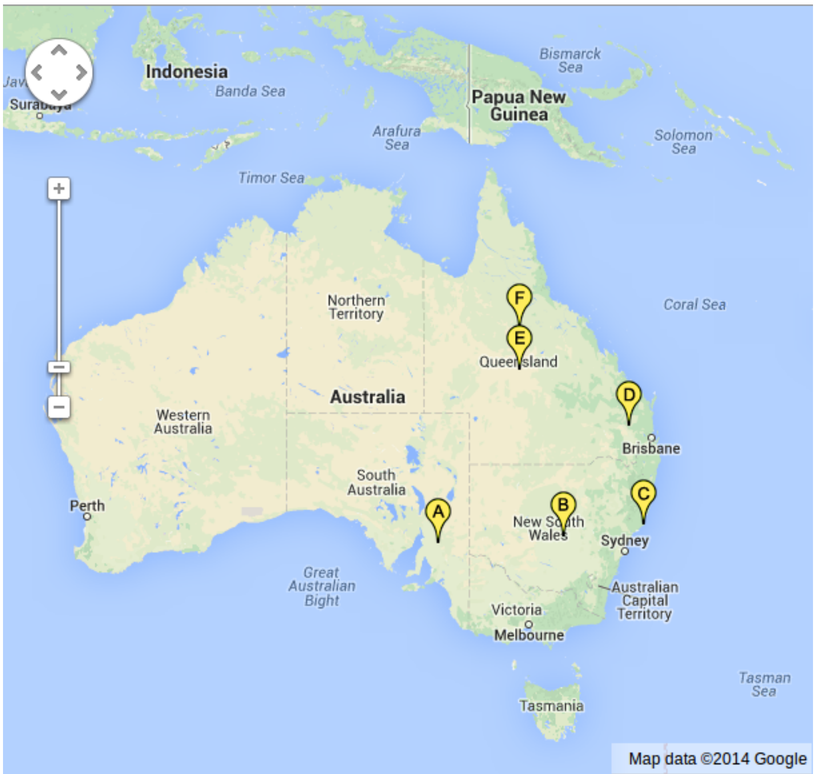


Figure 8.2: Map of wind sites: Hallett (A), Condoblin (B), Myall Lake (C), Cooranga (D), Longreach (E), Hughenden (F). Source: Google Maps

Myall Lake in NSW, and Longreach, Cooranga and Hughenden in Queensland. Hallett in South Australia is the site of an established wind farm in the same wind regime as much of the presently installed wind capacity in the NEM. Hallett is chosen as a reference site to compare the wind in more diverse locations.

Hourly time series data for January 2010 were also modelled for 22 km × 22 km cells in an 1,100 km × 1,100 km region around Hallett to examine the cross-correlation of the hourly wind speed data as sites move further away from Hallett. The temporal range was restricted to January 2010 due to the computational workload. The heat map in Figure 8.3 confirms that the cross-correlation between Hallett and other sites diminishes with increasing distance from Hallett. The shape of the heat map is not symmetric about the y-axis, but the map illustrates that sites in the north-east, north-west and south-east corners – at a distance of over 700 km from Hallett – have no cross-correlation with wind speeds at Hallett in the centre.

Table 8.1 shows the cross-correlation coefficient of hourly wind speeds between

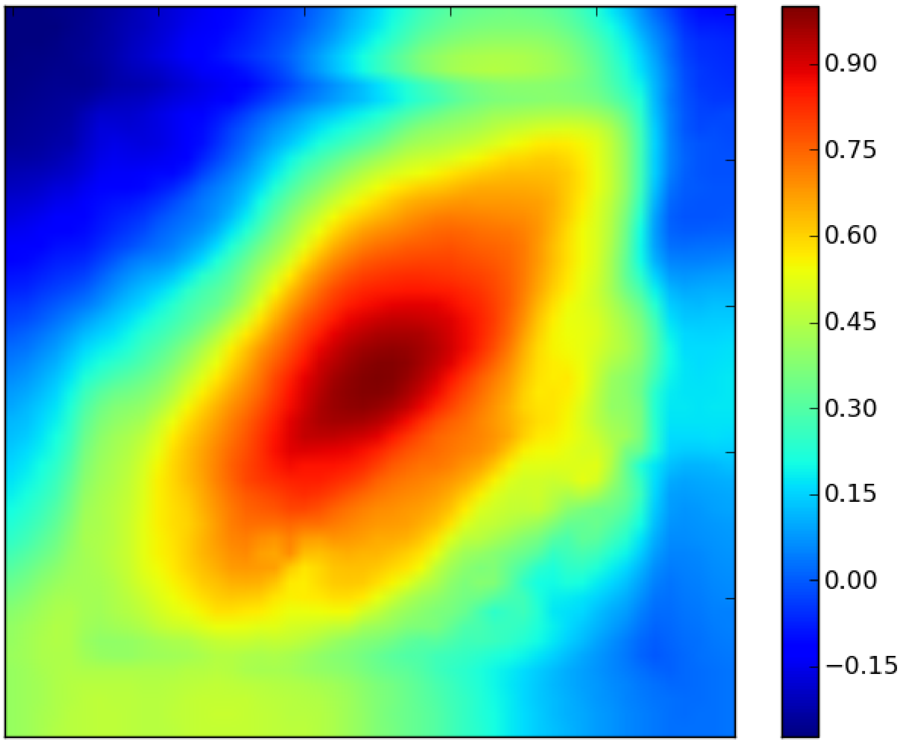


Figure 8.3: Cross-correlation of wind speeds between Hallett (centre cell) and neighbouring 22 km × 22 km cells over an 1,100 km by 1,100 km region in January 2010

	Jan.	Feb.	Jun.	Jul.	Aug.
Condoblin, NSW	0.16	-0.07	0.49	0.61	0.42
Longreach, QLD	-0.21	0.03	0.09	0.10	-0.07
Cooranga, QLD	0.06	0.10	0.16	0.44	0.03
Hughenden, QLD	-0.07	0.09	0.10	0.12	-0.09
Myall Lake, NSW	0.07	0.14	-0.16	0.01	-0.05

Table 8.1: Cross-correlation of 2010 hourly wind speeds with Hallett

Hallett and the remaining sites in two summer months (January and February) in 2010 and two winter months (June, July and August) in 2010. Winter wind speeds in Condoblin have a higher cross-correlation with Hallett than any other location. All of the sites have favourably weak correlation with Hallett in the summer months. Wind in Cooranga and Hughenden is less correlated with wind in Hallett and other existing wind farms, so wind farms in these two locations are expected to lift the minimum level of wind generation throughout the simulated year. Hughenden, being even further from Hallett than Cooranga, has a lower cross-correlation with existing wind farms.

To gauge the effect of greater wind diversity in reducing bioenergy consumption, part of the wind generation in the simulations in Chapter 5 is substituted with output from hypothetical wind farms at Hughenden and Cooranga. Annual wind generation is maintained at 66 TWh, the 30% contribution from wind selected for the technical feasibility study in Chapter 5.

System Advisor Model (SAM) was used to model the hourly power output of 57.6 MW wind farms in the two chosen locations, each being comprised of 32 Vestas V100-1.8 machines. Although the SAM software modelled only solar power systems initially (SAM originally stood for Solar Advisor Model), recent versions include performance models for other renewable energy technologies, including small-scale wind power, utility-scale wind power, geothermal power, and solar hot water. SAM uses a human-readable file format for wind input data called SWRF (SAM Wind Resource File). The SWRF file specifies 8,760 hourly wind speed, wind direction and temperature values at a range of heights: 200 m, 100 m, 50 m, 20 m and 10 m. The National Renewable Energy Laboratory (NREL) confirmed that for modelling the performance of wind turbines in the range of typical hub heights (50–100 m), only 50 m and 100 m data are required. Intermediate values are interpolated. A small AWK[2] program was written to translate wind speed, direction and temperature time series data from TAPM output files into the SWRF file format.

A new generator type called 'SAMWind' was added to the library of simulated generators described in Section 4.4. The SAMWind generator simulates power output by reading a file of hourly wind generation from SAM (normalised to a rated capacity of 1 MW) and scaling it to the desired capacity. A new wind farm was created for the simulations described in Chapter 5 and inserted into the merit order with the existing wind farms. The capacity of the new wind farm was chosen such that the energy generated by the hypothetical wind farm matched the wind energy being relocated from existing locations.

8.2.3 Analysis

The result of adding the new wind farms is shown in terms of annual requirement for bioenergy (Figure 8.4) and running hours for the gas turbines (Figure 8.5). As can be expected by choosing two sites with weak cross-correlation with existing sites, the number of running hours for gas turbines and the total generation from the gas turbines is reduced. In the case of Hughenden, the relocation of 24 TWh of wind energy to northern Queensland results in almost a 10% reduction in bioenergy consumption. If relocating wind farms into northern Queensland was taken to the extreme, the bioenergy requirement in Figure 8.4 can be expected to start rising once the majority of the wind generation is again in a single wind regime.

Although the Cooranga and Hughenden sites show promise in a more diverse fleet of wind farms, they are not necessarily as profitable as existing wind farm sites. They may require significant transmission line expansion and may have lower capacity factors, although Hughenden has been identified by one wind farm operator as the site for the future Kennedy Wind Farm. Capacity factors were not considered in this analysis, as the capacity of the wind farm was explicitly set

[2]AWK is a programming language suited to text processing.

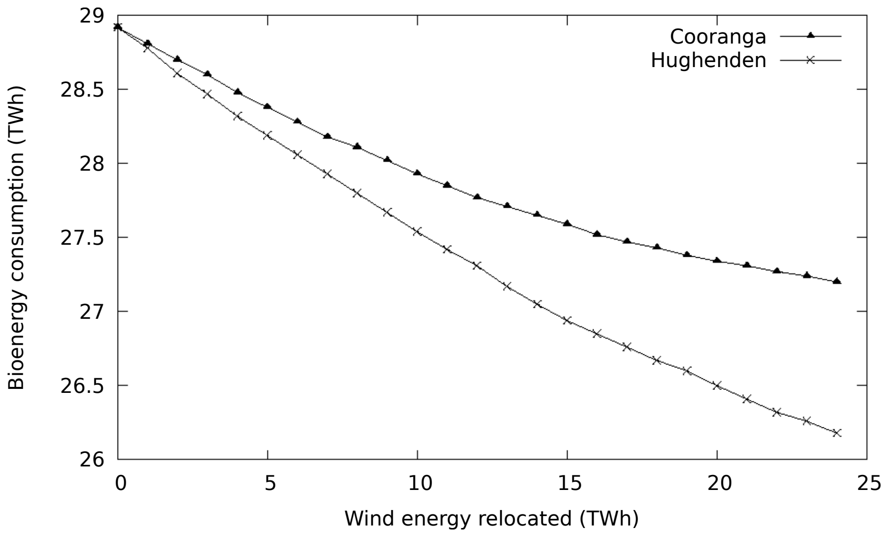


Figure 8.4: Annual requirement for bioenergy with an increasing amount of wind power relocated to northerly locations

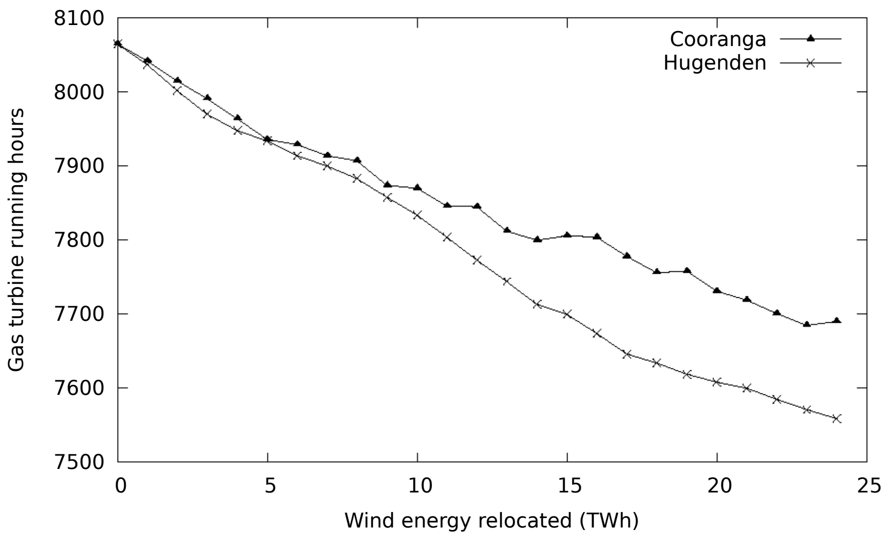


Figure 8.5: Annual running hours of gas turbines with an increasing amount of wind power relocated to northerly locations

to achieve the required amount of annual energy generation relocated from the southern part of the country.

This small experiment demonstrates that dispersing wind farms across the NEM can substantially improve the contribution of wind power to meeting demand, and reduce the requirement for other more costly forms of generation. In Chapter 5, generation from biofuelled gas turbines was 28 TWh (or around 13% of annual generation). When the optimisation model was applied in Chapter 6, maximum annual generation from biofuelled gas turbines was constrained to 20 TWh, but even less (around 10 TWh, depending on the input assumptions) was generated due to the high fuel cost of bioenergy and the availability of lower cost options.

For further work, a more detailed search for wind sites with favourable cross-correlations should be undertaken with a more comprehensive wind climatology. The two hypothetical wind farms described above could be simultaneously introduced into the optimisation model. This would be a useful investigation, as the economics of siting wind farms in distant, more varied wind regimes could be evaluated against the cost of operating biofuelled gas turbines with a high fuel cost.

8.3 Periods of low direct normal irradiance

In this section, satellite-derived hourly solar irradiance data for Australia over the period 1998–2010 inclusive, are used to characterise the frequency and duration of runs of low DNI across the entire Australian continent at a spatial resolution of 5 km × 5 km. As part of previous efforts to characterise the solar radiation resource, it has been common to quantify the annual frequency of runs where solar radiation does not exceed a threshold value. This is typically done using daily insolation measurements and usually only from a single location (Exell 1976; Baker and Enz 1979). The spatial relationship of these historical periods of low DNI is then examined, showing how dispersed CST power stations can help minimise the impact of these periods.

The primary concern for the integration of solar electricity at high penetration is the variability of solar radiation over various time scales (Denholm and Hand 2011). At the time scale of seconds to minutes, variability creates difficulties for balancing, frequency control, and voltage control. Variability on time scales of hours to a day ahead influences unit commitment of other generators to maintain adequate supply reserves. On even longer time scales of days to weeks and beyond, variability influences decision making for power security issues including scheduled generator maintenance. A valuable research question for future high penetration renewable electricity systems is the degree to which concentrating solar thermal power and photovoltaic power can contribute in a mixture of different generating technologies.

Solar power systems, unlike wind and wave power, do not suffer the adverse effects of excessive energy availability. Wind and wave power machines must be built to withstand forces far in excess of what is typically encountered in the field. However, an unexpected lack of energy outside normal statistical parameters is of concern for solar power system planning and operation. If an extended period of low irradiance occurs, there must be sufficient generating capacity installed elsewhere in the power system to offset the shortfall in supply. Reserve capacity represents generating equipment that is idle much of the time, adding to the overall cost of electricity supply.

The frequency and duration of protracted periods of low DNI is of particular interest for modelling the operating performance of CST power plants because these periods characterise the duration of what is essentially a forced outage. As with the forced outage of a conventional thermal power plant, it is necessary to plan sufficient reserve generating capacity to meet this contingency. For CST power plants, electrical power output declines rapidly once DNI falls below a critical threshold. Depending on the CST design in use, this threshold can be the level of irradiance required to first overcome power losses in the receiver and then to achieve the minimum turbine load. A value of 400 W/m^2 has been chosen as broadly representative across a range of CST power plants operating today.

Figure 8.6 shows the non-existent electrical power produced by a 100 MW parabolic trough plant without storage simulated in SAM during a three day

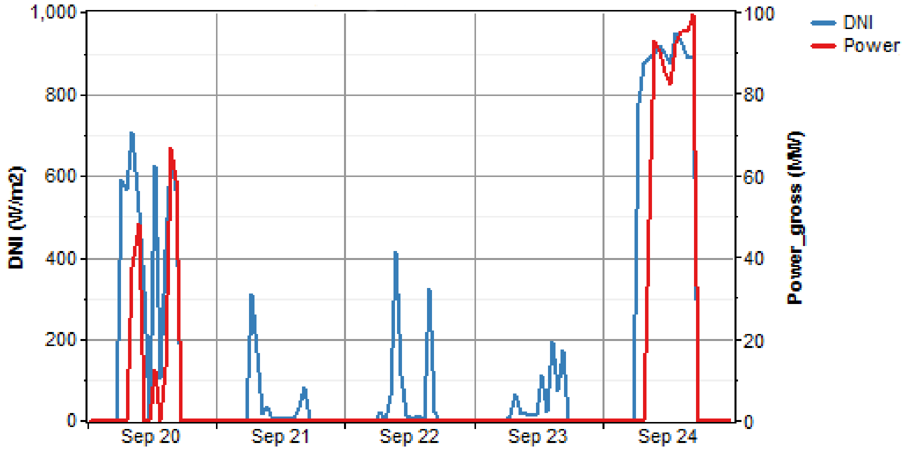


Figure 8.6: Simulated 100 MW trough plant in Cobar, New South Wales, September 2009

period of low DNI. In a CST system with thermal storage, a protracted period of low DNI much longer than the number of full-load hours of thermal storage, will exhaust all stored energy.

A range of CST plant designs are in operation today. The early Solar Electric Generating Station (SEGS) plants in California, have no thermal energy storage. Others, such as Andasol-I and Gemasolar in Spain are equipped with 7.5 and 15 full load hours of thermal energy storage, respectively. This storage enables the plants to continue operating through short periods of low irradiance. However, less common periods of low irradiance lasting several days cannot be overcome by thermal energy storage. It is unlikely to be economic to incorporate enough thermal storage to withstand such events. During such an event, a CST power plant would require an auxiliary fuel source (eg, natural gas) to continue operating. Wright and Hearps (2010) have proposed biomass co-firing of CST plants.

It is now useful to ask how long are periods of DNI below 400 W/m^2? How frequently do they occur? When during the year – and where – do they occur?

8.3.1 Analysis technique

An exhaustive analysis of satellite-derived surface solar irradiance data has been completed using the solar radiation data set from the Bureau of Meteorology (Bureau). As described in Chapter 4, the solar radiation data is imported into a

2001-07-01 00	to	2003-06-30 00
2006-04-16 07	to	2006-04-17 20
2009-11-11 08	to	2009-11-12 18
2008-03-13 07	to	2008-03-17 20
2008-04-09 07	to	2008-04-13 21
2009-11-15 08	to	2009-11-27 18
2009-02-16 07	to	2009-02-18 20

Table 8.2: Hour ranges of extended runs of missing data. Date and hour numbers are in Coordinated Universal Time (UTC).

large 3-dimensional array where all missing hourly grids are filled in with 'nodata' values. This permits simple iteration through the data set along the major axis. The data span a 13 year period from 1998 to 2010 inclusive and represent the most comprehensive historical record of solar irradiance for the Australian continent. Although the Bureau has collected this data for some time, there has been little analysis of this data performed in the context of power system operation. A computationally efficient method is described for determining long periods of low DNI.

To find the longest period of insolation below a given threshold, the program iterates through the DNI array, hour by hour, and records the longest sequence of hours in each cell where the irradiance is below a threshold in each grid location (y, z). To speed up the search, the independent nature of the data is exploited. The DNI data are stored as 113,952 hourly grids of dimensions 679×839. Searching for runs of low irradiance necessarily introduces a dependency between grid n and grid $n+1$, but within an hourly grid, each cell can be examined in parallel. To avoid classifying long sequences of missing data ('nodata' values) as a period of low DNI, the data were scanned to find sequences longer than 24 hours of hourly grids where the whole continent contains the 'nodata' value. These hour ranges were then recorded and used to eliminate low DNI runs from the candidates (see Table 8.2).

At each time step, three 679-by-839 matrices are updated: **B** is a matrix of binary values indicating whether irradiance at the current time step is below the threshold (with 1 indicating that the value is below the threshold), **C** is the current count of consecutive hours below the threshold, and **M** is a matrix containing the maximum number of consecutive hours encountered thus far. As the program iterates through the hourly grids, the current count of hours below the threshold is computed using an entry-wise product (Eq. 8.1). As **B** contains only binary values, this will either increment the count in a cell or reset it to zero (Eq. 8.2). At the end of each time step, **M** is updated (Eq. 8.3). This technique permits the use of fast matrix operations and avoids the need to loop over each element of the matrices, giving high performance and acceptable running time.

$$\mathbf{C} = (\mathbf{C} + \mathbf{B}) \circ \mathbf{B} \tag{8.1}$$

$$c_{i,j} = \begin{cases} (c_{i,j} + 1) \cdot 1 = c_{i,j} + 1, & \text{if } b_{i,j} \text{ is } 1 \\ (c_{i,j} + 0) \cdot 0 = 0, & \text{if } b_{i,j} \text{ is } 0 \end{cases} \tag{8.2}$$

$$\mathbf{M} = max(\mathbf{M}, \mathbf{C}) \tag{8.3}$$

8.3.2 Interpretation of the results

At the end of the run, the program outputs the **M** matrix and a second matrix giving the starting hour number between 0 and 113,951 for each of the longest DNI periods in **M**.

Figure 8.7 shows that across the Australian continent, the location having the minimum run of DNI below 400 W/m^2 over the 13 years is around four days. In many locations along the eastern coastline and into the northern tropics where rainfall is greater, these events can extend to over seven days. In far north Queensland, the longest events extend to a maximum of around 20 days. This anomaly was investigated more closely and found to be due to a record high rainfall event in January/February 2009 in this region. The starting day of the year for these events across the continent (see Figure 8.9) shows that these events can occur at any time of the year, but there is a trend for them to occur in winter in the south-eastern part of the continent and during summer in the northern, tropical region of Australia.

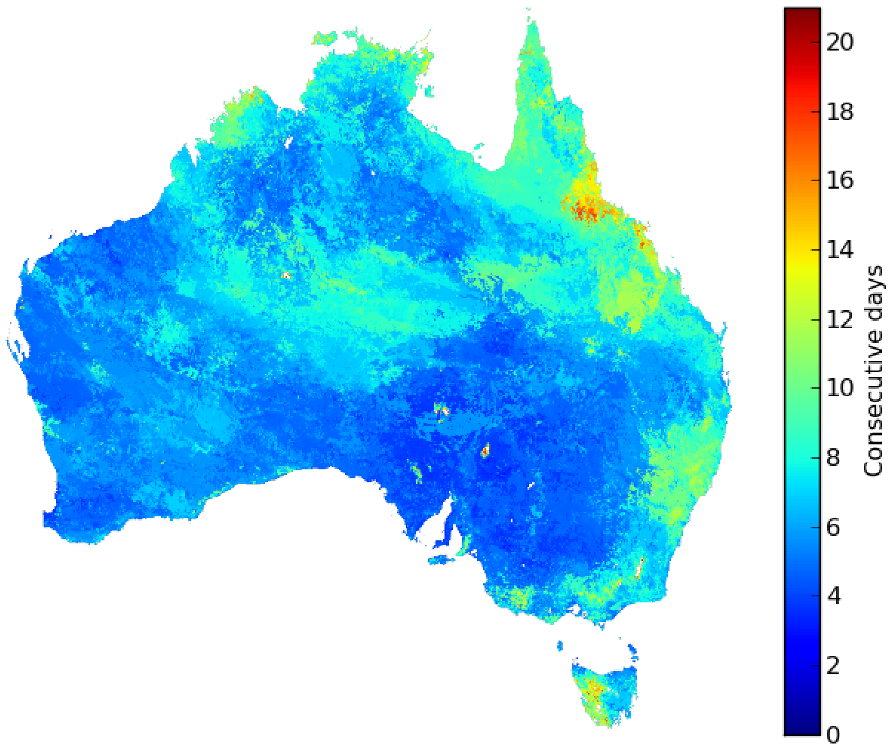


Figure 8.7: Length of longest run of DNI below 400 W/m^2

To obtain some insight into the frequency of such low irradiance events, the inland location of Roma, Queensland was selected for closer examination (shown on a map in Figure 8.8). Roma was chosen as a potential site for CST in one Australian scenario (Wright and Hearps 2010) due to its high average annual direct normal insolation and access to the existing transmission network. The ten longest events for this location are listed in Table 8.3. There are four events of six days duration (1998, 2000, 2008, 2010) in the 13 year period. Four of the 10 longest events in Roma occurred in the year 2000.

The minimum value in the result matrix **M** is 89 hours and this occurred at Curnamona, South Australia (shown on a map in Figure 8.8). The ten longest events in Curnamona are listed in Table 8.4. Again, the ten longest low irradiance events are found to occur in eight of the 13 years. In 2004 and 2007, two events occurred in the one year. The duration of these events (in hours) quickly tails off at around 64 hours. The duration of these events will have a tendency towards a diurnal distribution, as periods of DNI do not end during the night.

Figure 8.8: Map of CST sites: Curnamona (A) and Roma (B). Source: Google Maps

Start date	End date	Hours	Days
2000-02-12	2000-02-18	139	6
2008-01-14	2008-01-20	138	
2010-02-27	2010-03-05	136	
1998-12-29	1999-01-03	134	
2010-09-16	2010-09-21	115	5
1998-04-13	1998-04-17	113	
2000-04-22	2000-04-26	113	
2000-11-13	2000-11-17	111	
2010-01-03	2010-01-07	110	
2000-11-07	2000-11-11	109	

Table 8.3: 10 longest events in Roma, Queensland

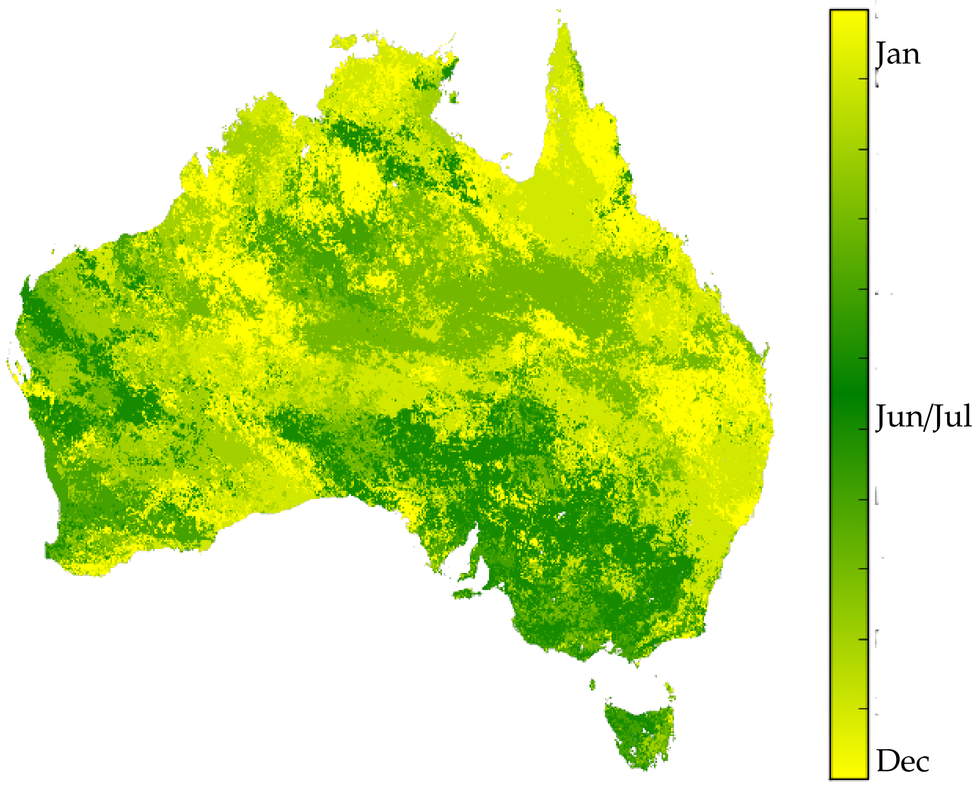


Figure 8.9: Seasonal timing of longest runs of DNI below 400 W/m^2

Start date	End date	Hours	Days
1998-07-31	1998-08-04	89	4
2007-01-17	2007-01-20	83	
1999-03-24	1999-03-27	71	3
2004-05-31	2004-06-30	66	
2000-03-18	2000-03-20	65	
2006-07-13	2006-07-15	65	
2007-03-18	2007-03-21	65	
2004-07-22	2004-07-24	64	
2005-07-06	2005-07-08	64	
2010-02-01	2010-02-03	64	

Table 8.4: 10 longest events in Curnamona, South Australia

8.4 Chapter summary

Characterising renewable energy resources such the wind or solar radiation is crucial for the successful integration of these sources into electricity system at high penetration. In Section 8.2, it was shown that bioenergy consumption in gas turbines can be reduced significantly in the scenarios of Chapter 5 by relocating a share of the total wind energy from the existing NEM wind farm locations into new areas at great distance, such as northern Queensland, where the wind is poorly cross-correlated with the wind in the southern states. The dispersion of wind farms allows the gas turbines in the scenarios to run less often and consume less bioenergy.

In Section 8.3, extended periods of low DNI were found to be much longer than the capacity of thermal storage incorporated into current CST plants, and they were found to occur frequently in the 13 year analysis period. There is a reasonably strong tempo-spatial pattern observed with low DNI periods occurring in the winter in the south and in the summer in the tropical north. To reduce periods of low CST contribution in a 100% renewable electricity system in the NEM, it may be necessary to consider possible sites at a range of latitudes. Some of the sites with favourably shorter periods of low DNI, such as Curnamona, South Australia, as presented in this chapter, are not necessarily sites that would be chosen for high annual insolation.

Chapter 9

Insights

> *You can only turn a power plant down so much. A Prius comes to a stop at a red light and the engine shuts off. When the light turns green, the engine starts up again. Power plants aren't like that – if you turn it off, you have to keep it off for hours. Also, it's really expensive to turn a power plant on and off.*
>
> – Paul Denholm

9.1 Introduction

This chapter reflects on the results from Chapters 5 to 8 and draws together the key findings and their implications. The 100% Renewables Study completed by the Australian Energy Market Operator (AEMO), foreshadowed in Chapter 3, is examined in Section 9.2 in detail. The AEMO scenarios also focus on the National Electricity Market (NEM) and it is instructive to compare their results with mine. Section 9.3 examines how a 100% renewable electricity system might differ from the conventional system. Scenarios of 100% renewable electricity require a rather different method of operating the electricity supply-demand system compared with the system that is in place today. Section 9.4 examines the sensitivity of the results to different assumptions. The research demonstrates that within a narrow range of annual costs, there are numerous mixes of generation that can meet the reliability requirements. The question of whether 90% renewable electricity would be much lower cost than 100% is briefly discussed in Section 9.5. In Section 9.6, some of the next steps in analysing the grid integration challenges of renewable electricity at high penetration are described. These have not been mentioned in Chapter 3 because no results in this area of work have yet been published in the literature. Finally, some limitations of the present research are identified in Section 9.7.

9.2 Comparison with AEMO 100% Renewables Study

The AEMO 100% Renewables Study (hereafter, the AEMO study) was briefly introduced in Chapter 3 and is examined in more detail in this section. After the 2010 Australian federal election, the Multi-Party Climate Change Committee (MPCCC) commissioned the power system operator, AEMO, to undertake a detailed operational review of 100% renewable electricity in the NEM. The AEMO study was well resourced, with third party organisations engaged to compile renewable energy resource data for the AEMO team. The final report from AEMO was released shortly *after* the second of three papers on the subject was published by the author (Elliston et al. 2012a, 2013). The AEMO study is the most relevant to the research presented in this thesis in its approach and, in particular, for examining the NEM.

9.2.1 Overview of the scenarios

The AEMO study (AEMO 2013a) evaluates the technical feasibility and cost of two scenarios in two different target years: 2030 and 2050. The two scenarios make different assumptions about rates of technological progress, including cost reductions, and rates of demand growth. Scenario 1 assumes fast technological transformation and moderate demand growth. Scenario 2 assumes moderate technological transformation and high demand growth. Like the present work, the AEMO study determines the cost of the system in the target year, not the cost of the transition from the present system to the 100% renewable system over a number of decades.

9.2.2 Assumptions

Like the present research, the AEMO study models the electricity sector only and does not consider the possibility of fuel switching in other sectors of the economy to renewable electricity. One exception is that the scenarios include electric vehicle charging as a form of flexible demand response. Demand response is not considered in the present research. With the exception of some electric vehicle charging, the AEMO study differs from the Beyond Zero Emissions Zero Carbon Australia Stationary Energy Plan for Australia (Wright and Hearps 2010), which advocates widespread electrification of space heating, cooking and transportation as the easiest pathway to zero emissions energy sources for these uses.

A number of other assumptions in the AEMO study are shared with the present research. AEMO only examines renewable forms of low carbon electricity. As part of the project scope, AEMO was instructed to exclude other low carbon options such as carbon capture and storage (CCS) and nuclear power. As in this work, existing hydro is included in the scenarios. AEMO found that batteries, new pumped storage facilities and compressed air were all uneconomic storage technologies, as there are sufficient existing storage technologies commercially available in the form of hydro, concentrating solar thermal (CST) and biofuelled gas turbines. This finding supports some of the technology assumptions made in this thesis.

A number of critical assumptions differ between the AEMO study and this work which significantly alter the shape of the scenarios. First, AEMO included a number renewable energy (RE) technologies that AEMO believes are likely to be commercially available in 2030 and/or 2050, but are not commercially available at present. They include utility-scale photovoltaic (PV), central receiver CST with nine hours of thermal energy storage, wave power, and hot sedimentary aquifer (HSA) geothermal. This is in contrast to the more conservative choices in this work, where only technologies available today are included, namely rooftop PV, wind power, parabolic trough CST with thermal storage, existing hydro, and gas turbines fuelled with biofuels. AEMO includes a number of technologies that can be used for meeting a large fraction of the baseload demand (eg, HSA geothermal). In this work, no generator technology was chosen that can operate at such high capacity factors.

The AEMO study includes a strong level of demand-side response. Half of this response is curtailment of demand that comes at a cost to end-users, and is included in the economic modelling. The other half is shifting load into the mid-day hours to better utilise low cost, less controllable PV generation. The load shifting is assumed to have zero cost. Finally, the AEMO model introduces new transmission links, both alternating current (AC) and high voltage direct current (HVDC), costed appropriately.

9.2.3 Modelling approach

The AEMO study models a range of generation mixes to meet the NEM reliability standard at least cost using an iterative process. The model also estimates the network augmentation that would be required to transform the present NEM transmission network. Although this is much more detailed than the simple estimation of transmission requirements in Chapter 4, AEMO produces similar cost estimates for transmission network augmentation of around 10% of total capital costs.

The AEMO study divides the geographic area of the NEM into 43 polygons (see Figure 9.1). Third parties were engaged by AEMO to produce traces of hourly RE resources, where applicable, in each polygon. This contrasts with the present work, where renewable generation is determined in specific locations (as for CST plants) or entire NEM regions such as aggregate wind power in South Australia.

AEMO used two modelling tools: a probabilistic generation expansion model and an hourly time sequential model for a single year. Each model is operated independently and adjusted after an operational review and a transmission review. Mai et al. (2012) and AEMO demonstrate the value of using multiple models at different levels of simulation detail. This approach allows promising candidates found through a fast optimisation to be fed into more detailed, slower models. Running the same candidates through two independent models can improve confidence if they produce similar results. In the present research, a simpler, faster

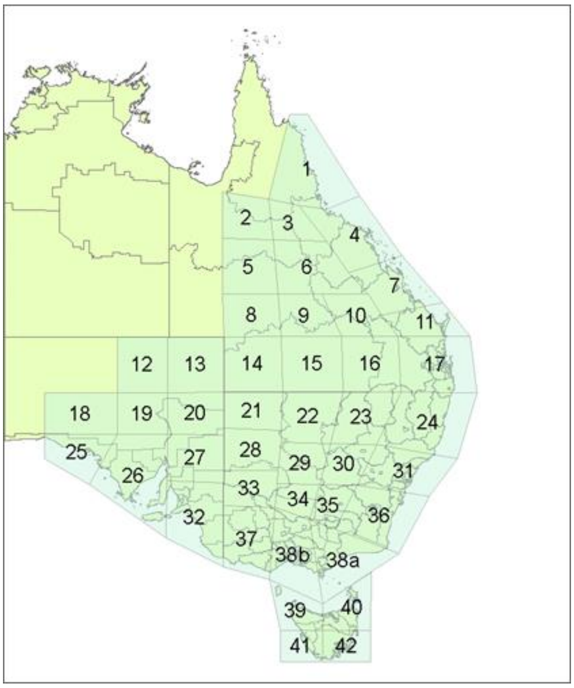


Figure 9.1: NEM locational polygons. Source: AEMO (2013a)

chronological model was used that runs quickly enough to use it for optimisation.

The probabilistic model creates 5,000 days of synthetic weather and load data for all four seasons. Hourly traces of renewable energy production and demand profile in each polygon is generated with a probability distribution function. The probabilistic model gives a good indication of the ability of the system to meet the reliability standard with a range of weather conditions and loads experienced. One weakness of this approach is that modelling individual days does not consider the weather of the previous day. Importantly, the solar radiation conditions of the day or two prior to the modelled day have a significant impact on the dispatch behaviour of CST plants and their ability to compensate for poorer conditions on the simulated day.

The time sequential model simulates the chosen generation system in a chronological fashion for a given historical year of weather data, as in the present research. This gives a more complete picture of whether power and energy demands can be met over an entire year. In more detail than the present model, the AEMO time sequential model imposes ramp rate limitations on the simulated generators. Furthermore, AEMO introduces a useful idea into its chronological model.

While generators are normally dispatched in order of marginal cost of generation, the time sequential model dispatches generation out of merit order in two circumstances:

- to overcome a transmission constraint that prevents lower marginal cost generation from being transmitted to a region – contrary to the approach taken in this research (where dispatch always occurs in merit order because there are never transmission constraints); and
- to maintain a minimum level of 15% synchronous generation at all times.

9.2.4 Costs

AEMO uses the same projected RE technology costs from the Australian Energy Technology Assessment (AETA) as the present research (Bureau of Resources and Energy Economics 2012a). Whereas in Chapter 6, capital costs from AETA were taken at the low and high end of the range, AEMO used the midpoint. AEMO modified some costs with alternative inputs from ROAM Consulting and the CSIRO, using its Global and Local Learning Model (GALLM) model. In the AEMO study, Scenario 1 considers the possibility of more rapid technological development and deeper reduction in costs than was assumed in AETA. For this scenario the AETA capital cost projections are too conservative. Costs in the year 2012 are taken from AETA and put through the GALLM model with more optimistic learning rates than were assumed in AETA. For Scenario 2, capital costs were taken directly from AETA. AEMO notes that the capital costs will ultimately be higher than they have estimated due to the higher costs of technology encountered over the transition period. Against this, however, the future costs are highly uncertain. If they are lower than projected by AETA, the higher capital costs predicted by AEMO may be avoided.

AEMO also used operating and maintenance (O&M) costs from the AETA. Scenario 2 uses the AETA assumption that O&M costs escalate at 150% of the Consumer Price Index (CPI) each year. Scenario 1, however, assumes that O&M costs will also be reduced with improved learning, the gradual replacement of original equipment with more reliable components, and greater operational experience. Hence, O&M costs are reduced by 12.5% by 2030. While this approach was not taken in the present research, it is a reasonable assumption and it would be valuable to calculate the cost impact on the present scenarios using these alternative O&M costs. In calculating costs, AEMO ignores additional costs associated with acquiring land, any necessary augmentation of the distribution network, and stranded assets. These are also excluded in the present research. AEMO assumes the cost of biogas (in $/GJ) from a report produced by the CSIRO to support the AEMO study (James and Hayward 2012). This report was unavailable at the time of the present modelling work, but the CSIRO values are comparable to the values chosen in Chapter 6. Gasified biofuel has been estimated at around $9/GJ adding $80/MWh-e to the variable O&M of the gas turbines (depending on the gas turbine heat rate).

AEMO estimates that the wholesale costs of electricity in its four scenarios range from $111–112 per MWh (scenario 1) to $128–133 per MWh (scenario 2). This is commensurate with the estimates of $96–154 found in Chapter 6 for the present 100% renewable electricity scenarios. AEMO estimates the projected impact on retail electricity tariffs at $66 to $85 per MWh. AEMO also estimated that transmission network augmentation would add $6-10 per MWh to these wholesale costs of generation.

9.2.5 Observations from the AEMO study

Despite the similarities of the AEMO study and the present research, some differences in assumptions and modelling approach leads to some insights that are beneficial to this field of research. Here, the key aspects of the AEMO scenarios will be contrasted with the present scenarios.

AEMO made different choices for the available RE technologies. The technologies not modelled in the present scenarios include: HSA geothermal, woody biomass, bagasse, and wave power. AEMO indicates that HSA geothermal has significant potential due to its high capacity factor, providing 26% to 30% of energy in Scenario 1, but almost none in Scenario 2 – its contribution is highly dependent on the technology maturing and costs reducing. Hot dry rock geothermal, on the other hand, is found to be economically nonviable in all of the AEMO scenarios. Figure 9.2 shows the share of generation from the various renewable sources in the four AEMO scenarios and in two of the present (low and high cost, 5% discount rate) scenarios. The plots are normalised for demand, but are not independent of the demand profile or other input assumptions and must be compared cautiously.

Figure 9.2 shows that although wave power, a technology still in the demonstration stage of maturity, is included in the AEMO scenarios, it still contributes very little energy by 2050. As a technology that is in its infancy today, wave power is more costly than more mature technologies. The plots also show that even without geothermal, bagasse or woody biomass generation to match baseload demand, the present scenarios do not utilise much more generation from biofuelled gas turbines. Substantially more low-cost gas turbine capacity is required however (see Figure 9.3) due to the greater share of variable generation. In all scenarios, 12 TWh was used as the long-term average generation from the existing hydro plants in the NEM. The share of hydro looks larger in the present scenarios (two right-most plots) because 12 TWh is a larger share in these lower demand scenarios. The AEMO scenarios all assume growth in demand.

AEMO (2013a) notes that the large share of rooftop and utility-scale PV capacity reduces summer peaks such that the NEM becomes a winter peaking system. The present research obtained a similar result, however the reduction in summer peaks came from rooftop PV and CST power stations. The use of demand side participation to shift demand into the mid-day hours redefines off-peak as the middle of the day. Total capacity of the AEMO scenarios, discussed further in Section 9.3.3, is more than twice the maximum demand. Like the present research, AEMO identified the evening peak in winter as the troublesome period, with large ramps occurring as PV power declines just as demand starts to rise to its evening peak. As with the present scenarios, this is handled with the capacity of CST, hydro and biofuelled gas turbines. This capacity is reduced somewhat in the AEMO scenarios due to the use of geothermal, bagasse and woody biomass generation that have predictable output throughout the evening

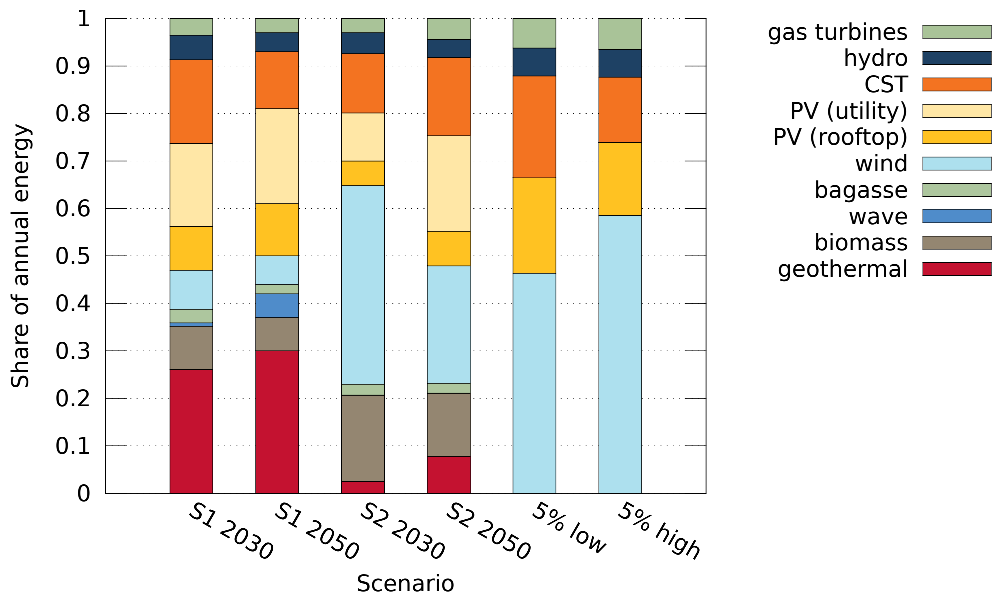


Figure 9.2: Share of energy for the four AEMO scenarios and the two 5% discount rate scenarios from Chapter 6 (low and high cost ranges). AEMO raw data unavailable; estimated from AEMO (2013a, Figures 12 and 14).

peak period. It should be emphasised that this observation does not confirm the need for 'baseload' generation. As this thesis shows, there are other approaches to balancing supply and demand during these periods. Furthermore, the difficulty is not in meeting the baseload, but in meeting specific peak load events. It is likely that the cost of additional gas turbines in the present research will be less than the cost of additional baseload capacity in the AEMO scenarios.

9.2.6 Summary

The AEMO study was a landmark report for energy researchers and policy makers in Australia, published after two of the author's journal papers (Elliston et al. 2012a, 2013) and apparently influenced by them. Carried out with higher spatial resolution and with a more detailed model, AEMO (2013a) notes, 'This operational review has uncovered no fundamental limits to 100 per cent renewable[s] that can definitely be foreseen at this time'. However, AEMO concedes, 'The resulting power system is likely to be one that is at or beyond the limits of known capability and experience anywhere in the world to date'. The AEMO study detailed in this section is similar enough in its approach and assumptions that the results can be broadly used as a validation for the results presented in this thesis. Where the two works differ, useful insights are gained.

9.3 New view of system operation

The scenarios advanced in this thesis entail a radical 21st century re-conception of the electricity supply-demand system, already flagged in some of the studies cited in Chapter 3. The electricity supply-demand system of today has evolved with the objective of following demand at all times, with little emphasis on demand modification except for relatively small amounts of energy arbitrage using pumped storage hydro, and load shedding to maintain system security. The generation fleet in Australia is mostly comprised of very mature generation technologies: pulverised coal plants, combined cycle gas turbines, hydro, and open cycle gas turbines for meeting peak demands. It must be stressed that all power generation technologies have different operating characteristics and limitations. These can be overlooked when discussing the limitations of current RE technology. These characteristics include plant reliability, large unit capacities, and limits to flexible operation including time to start from cold and warm conditions, minimum operating levels, and ramp rates.

The following sections discuss the new view of electricity system operation that emerges in the 100% renewable scenarios. Some of these operational aspects have been implied as a flaw or limitation of renewable electricity. The following sections will demonstrate that while these aspects are conceptually different to the present day system, they are neither significant nor detrimental.

9.3.1 Intermittent generation

The term *intermittent* is commonly used to describe variable renewable generation like solar PV and wind power (Riesz 2013b) and, moreover, the term may be used to imply that renewable electricity is necessarily unreliable. The appropriate terms for the generation profile of some renewable sources, such as wind and solar PV without batteries, are *variable* and *uncertain*.

Intermittence is a characteristic of all power generation technologies as none are perfectly reliable. Variability is not the primary difficulty in managing high penetrations of variable generation technologies. The challenge is that they are not as predictable as we would like from the perspective of power system control. As Riesz (2013a) has noted, it is helpful to classify renewable generation technologies into two services: bulk energy and firm capacity. Currently some fossil fuel technologies such as coal power are able to provide both services to a large degree (Riesz 2013a). Wind and solar PV have the potential to be very low cost suppliers of bulk energy in the future. Reliability services are potentially supplied by other technologies, by more advanced versions of the technology (eg, by wind turbines with integrated battery storage), or by improved weather forecasting.

As central power plant technology evolved throughout the 1950s and 1960s, electricity prices fell steadily (Brady 1996). Economies of scale allowed generators to supply electricity at steadily lower prices by increasing the generating capacity of power stations. The disadvantage of large plant capacities is that contingency planning becomes more difficult. The N-1 criterion ensures that sufficient generating reserves are maintained at all times as a contingency against the loss of the single largest generator in the electricity system. Large reserve margins and transmission line capacities are required to handle an unscheduled outage of a large power station.

With little warning, any power station can stop generating. There can be much less warning afforded to the power system operator than a forecast decline in wind speeds. Larger power stations are particularly vulnerable to localised disasters. In 2012, the Yallourn coal-fired power station in the Latrobe Valley of Victoria curtailed output following the flooding of coal conveyors at the neighbouring open cut mine. In February 2014, a bushfire near the Hazelwood power station, also in the Latrobe Valley, cut electric power to the coal dredgers at the mine. This power station also curtailed power output due to the interruption in fuel supply. Large generating units can pose just as many difficulties, albeit different ones, for reliable electricity supply as variable renewable generators. Specifically, forced outages of large thermal power stations are generally unpredictable, occur infrequently but suddenly, and may last weeks or longer. In contrast, 'outages' in a set of wind farms resulting from lulls in the wind are generally much more predictable, occur frequently but take several hours to reach a large reduction in total output, and generally last only a few days. Not all RE power stations can be classified as 'variable'. Hydroelectricity with large dams, biofuelled gas turbines with an adequate supply of fuel and, to some degree, CST with thermal storage may be classified as flexible and dispatchable, as discussed in the next subsection.

9.3.2 Baseload power

A commonly promoted idea to reject the use of RE for power generation is that it is unable to supply baseload power. As has been shown in Chapter 5, supply and demand can be balanced using a range of variable generation technologies in addition to the use of flexible generation that provides the firm capacity services described earlier.

The term *baseload* characterises the near-constant level of demand on a chosen time scale. It is not a description of the generator characteristics. In the present system, coal-fired power stations have become the dedicated suppliers of power to meet baseload because of operational limitations of the technology and because of their low marginal cost of generation. The power system operator dispatches generators in merit order with the first to dispatch having the lowest marginal cost of generation, subject to operational constraints. In the 100% renewable scenarios, the same principle applies. The technologies with the lowest marginal cost of generation and limited ability to be controlled, PV and wind power, are dispatched first. There is no requirement for baseload demand to be met by generation that is capable of maintaining constant output. Electricity users are concerned with supply reliability and power quality, not whether their demand is being met by generation whose output can be steadily maintained.

In this work, focus is shifted away from replacing baseload coal with alternative baseload sources. Instead, generation reliability is maintained in a system with large penetrations of variable renewable sources by having as great a diversity of locations as possible, large capacities of flexible generation, and storage. In such a 100% renewable electricity system, the concept of baseload power stations is redundant.

By contrast, the RE scenarios presented consist, to a much greater degree, of technologies that can be constructed at a range of capacities and have smaller individual unit sizes. Current wind turbines have rated capacities in the range of 2–8 MW. While there is the potential for an entire wind farm to go offline due to a single point of failure (eg, a substation), the failure of each wind turbine is an independent event. A lull in the wind can take an hour or more to propagate across a large wind farm; it can take a day or more to propagate across a system of dispersed wind farms. PV systems are modular, extremely reliable, and can be built at a range of scales, from small kilowatt-scale rooftop systems to ground-mounted systems with capacities in the hundreds of megawatts. One RE technology that benefits from economies of scale is CST, however there are not yet any gigawatt-scale CST plants. The Ivanpah CST plant, now operating in California, consists of three separate power towers of around 130 MW each. The open cycle gas turbines proposed for the present scenarios are produced in relatively small capacities up to around 350 MW. These small- to medium-sized units could be widely distributed in regions where biofuels are readily available. Transmitting electric power is likely to be more economical than transporting heavy solid or liquid biofuels from the point of production to power plants sited closer to loads (Searcy et al. 2007). It may also be cheaper than transporting gaseous biofuels via pipelines. One or two gas turbines could be located in a wheat farming district, for example, providing short distances to deliver crop residues from farms in the district.

9.3.3 Total generating capacity

In these scenarios, the total generating capacity is over three times the maximum peak demand of 33.6 GW experienced in 2010. Table 9.1 gives the total generating capacity for the four scenarios presented in Chapter 6 in gigawatts and as a multiple of the 2010 maximum demand. Having such a large total generating capacity is a marked departure from the way the system has been operated until

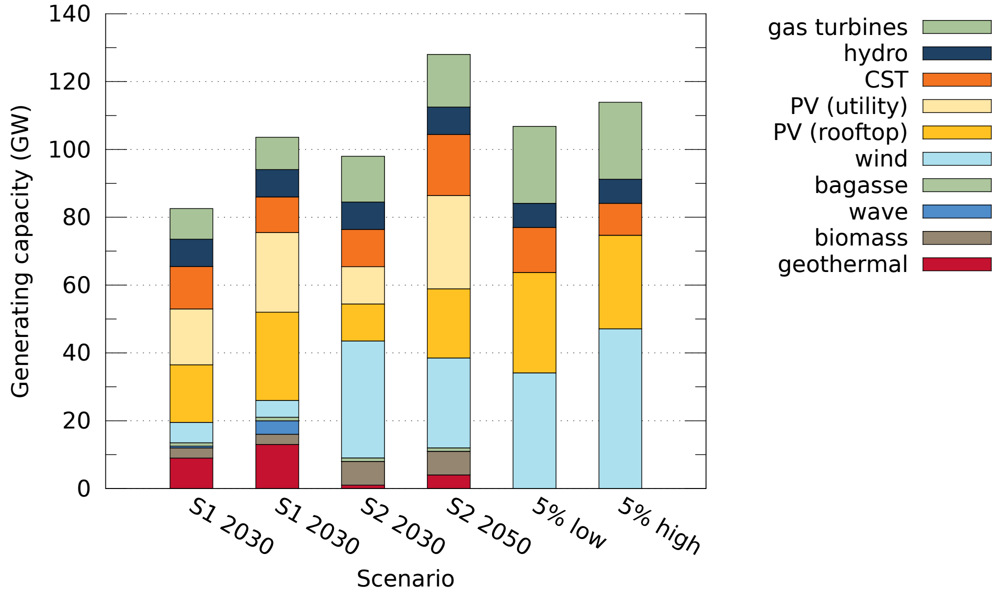


Figure 9.3: Generating capacities for four AEMO scenarios and the two 5% discount rate scenarios from Chapter 6 (low and high cost ranges). Data source: AEMO (2013a, Tables 15 and 16).

now, where maximum system capacity is determined by the forecast maximum demand plus a reserve margin to cover any forced outage contingencies. In the NEM today, there is approximately 50 GW of registered capacity for a maximum demand of around 35 GW. In contrast, the AEMO scenarios (which include a reserve margin) have a total capacity over twice maximum demand (AEMO 2013a), but not as high as the capacities in the scenarios presented in this thesis. In the present scenarios, which do not include reserve margins, a larger share of energy is supplied from variable renewables with lower capacity factors than the technologies chosen by AEMO (eg, hot dry rock geothermal). This allows the AEMO scenarios to have a total capacity closer to maximum demand. Figure 9.3 illustrates the generating capacities of the four AEMO scenarios and two low/high cost scenarios (5% discount rate) for the least cost systems identified in Chapter 6. Note that the AEMO and the present scenarios assume different demand profiles, so cannot be directly compared. The figure is provided for illustration.

Trainer (2013) has used the observation of high generating capacity as a criticism against the technical and economic merits of high penetrations of renewable electricity. Total capacity is of no greater prominence than the reserve margin

	5% discount rate		10% discount rate	
	low cost	high cost	low cost	high cost
Total capacity (GW)	106.8	113.9	103.4	116.8
Multiple of peak demand	3.2	3.4	3.1	3.5

Table 9.1: Total generating capacities of the four 100% renewable scenarios

in the conventional system of today. The issues at hand are the reliability of the overall system, the cost of the system, and the environmental impact of the generation system in terms of water use, land use, ecological sustainability, and conservation.

Gas turbines have low capital cost (about $800 per kW) and, if they are used infrequently as in the scenarios of this thesis, low operating cost. Therefore they may be considered to be reliability insurance with a low premium (Martin and Diesendorf 1982). Thus, in the present scenarios, with a large total capacity and a large capacity of gas turbines and other dispatchable generation, additional reserve capacity requirements may not be significant. The calculation of reserve margins for such a system is one area for future research.

9.3.4 Generation surpluses

Renewable generation does not always coincide with demand. Moreover, renewable generation can sometimes produce more power than the demand requires. These mismatches between supply and demand are often stated as a reason for delaying the use of RE until storage technologies become available such that the generator may be operated at a constant level of output – a facet of the so-called 'baseload fallacy' (Diesendorf 2007a). In the present scenarios, dispatchable generation is provided by a combination of hydro, pumped storage hydro (PSH), CST with thermal storage and gas turbines burning renewable fuels derived from bioenergy. In the simulations, only PSH and resistance heating of the CST storage medium are demands that can absorb surplus generation. Hence, surplus power is sometimes unable to be matched to demand. Figure 9.4 is a surplus duration curve which, similar to a load duration curve, shows the number of hours of surplus generation at a given level. Figure 9.5 shows the number of surplus generation events by hour. Figures 9.6 and 9.7 show the number of surplus generation events by hour and by season. There is a strong diurnal pattern of surplus generation around noon and less in the evenings. The marked difference in the number of surplus generation events between the low and high cost scenarios can be attributed to the greater use of wind in the high cost scenarios, as discussed in Section 6.2.

Previous literature, including papers by the author (Elliston et al. 2012a, 2013), have used the term *spill* to describe the situation of surplus generation. Spilled energy suggests that something scarce is irrecoverably lost. An alternative way of thinking about this situation is that variable generation is partially dispatchable (Mai et al. 2012) and may sometimes need to be dispatched downward. In the same way that conventional generation is turned down when it is not required, variable generation can also be turned down. That it *could* be generating is of no special significance. Variable generation like wind and PV that are dispatched downward could be available for dispatching upward subsequently, as the availability of power is reasonably predictable on short time scales. Indeed, it has been suggested that wind farms could participate in ancillary services markets for frequency control (Ela et al. 2014).

Surplus electricity is likely to initially have a low cost due to the lack of demand and could find alternative uses that do not require an uninterrupted electricity supply. These include irrigation, water purification, PSH, electric vehicle charging, water and space heating (Danish Government 2011), and 'power to gas' where electrolysis and, optionally, methanation is used to produce synthetic gas (Henning and Palzer 2014; Palzer and Henning 2014; German Federal Ministry of Technology and Economics 2010). Synthetic gas can be used in a variety of applications including as a fuel for open cycle gas turbines (OCGTs). Even without a way to use all surplus generation, the scenarios in Chapter 6 show that it can be more economical to accept a certain amount of surplus energy from variable generation than to build higher cost, high capacity factor power stations.

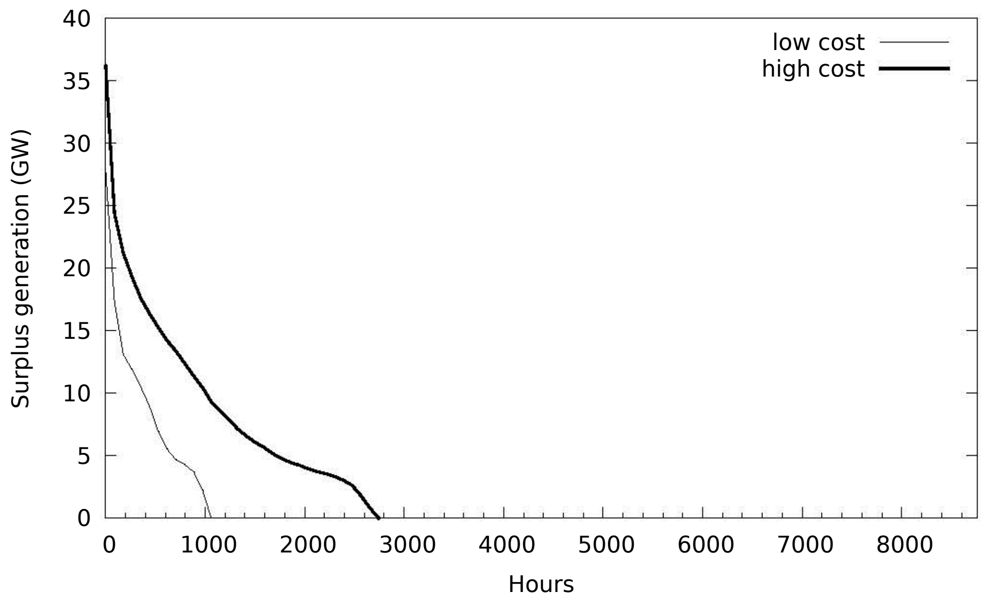


Figure 9.4: Surplus duration curve for 2010 (5% discount rate scenarios)

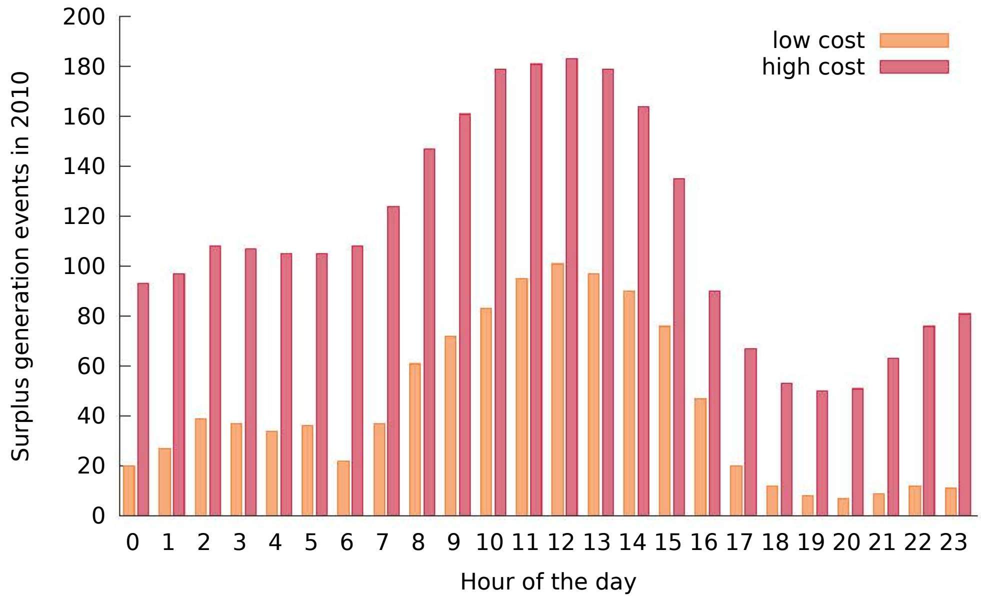
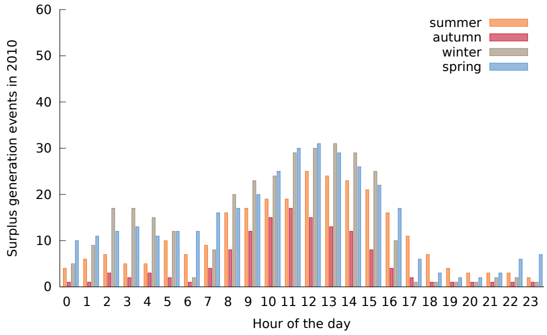
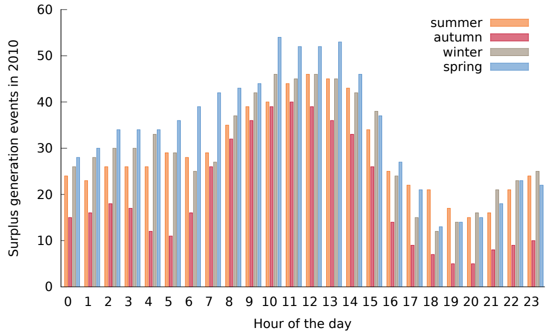


Figure 9.5: Surplus generation events in 2010 by hour of the day (5% discount rate scenarios)

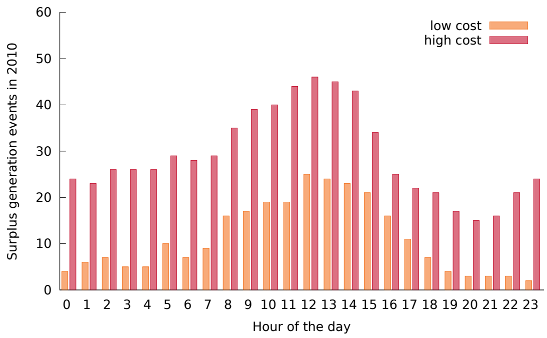


(a) Low cost scenario

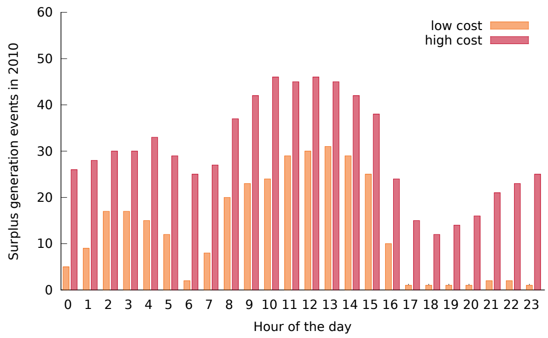


(b) High cost scenario

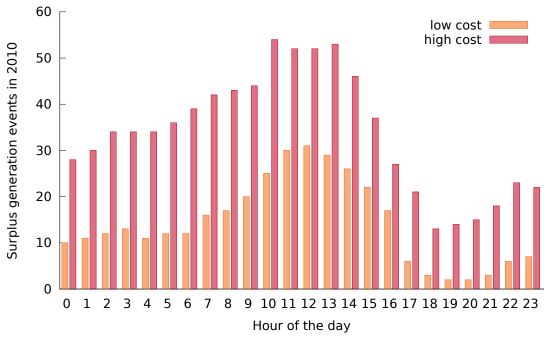
Figure 9.6: Surplus generation events by season (low and high costs, 5% discount rate)



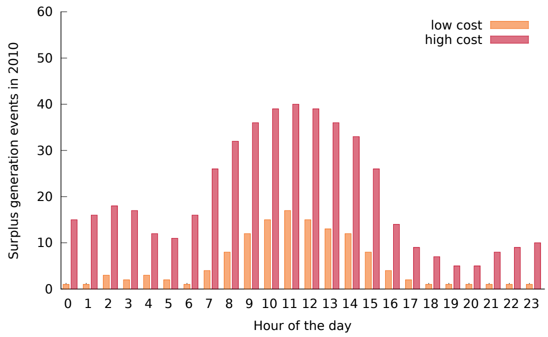
(a) Summer



(b) Winter



(c) Spring



(d) Autumn

Figure 9.7: Surpus generation events for each season

9.3.5 Flexibility

As noted in Chapter 4, an explicit decision was made to retain the unmodified NEM demand for 2010 to keep the input assumptions pessimistic. It is clear from the simulations that have been carried out that a 100% renewable electricity system must be more flexible. Constructing a load-following system without modifying demand is unlikely to be the most economical approach. Greater use of demand side participation to assist in balancing supply and demand is another departure from the way the present day system is operated. The use of information such as power availability and weather forecasts make it possible to construct appliances (eg, smart refrigerators and air conditioners) that can follow the availability of electricity supply, not the other way around.

The result is a system which is much more flexible on both the demand side and the supply side. The work presented in Chapter 5 shows that demand side response during the most challenging hours of the year not only allows supply and demand balance to be achieved, but can also reduce peaking capacity. During the hours of unmet demand in 2010, it was found that reducing these specific demand peaks by 19% allows a 9 GW reduction in gas turbine capacity.

Dispatchable generators such as hydro and OCGTs must be able to quickly adjust their output across a wide range to respond to changes in variable generation. There is little role in a high penetration system for other forms of dispatchable generation that cannot ramp easily or reduce its output to very low levels. This point is recognised in other studies such as Mai et al. (2012) where some amount of inflexible generation remained in the scenarios.

9.4 Sensitivity to input assumptions

While undertaking the least cost search in Chapter 6, it became evident that the operational reliability of the system is robust to different assumptions about costs and resource constraints. Many different 100% renewable system configurations can meet demand reliably and with little variation in overall cost, although with different compositions. This finding is consistent with Mai et al. (2012)[1].

The genetic algorithm used in this work imposes a high penalty on configurations that do not meet the reliability, hydroelectric generation or bioenergy generation constraints. The penalty functions increase as the cube of the difference between the given parameter and the target value. Solutions with annual costs similar to the least cost solution can be assumed to meet, or be very close to meeting, all three constraints. Table 9.2 shows the first four and last four generations of a single run of the genetic algorithm (GA). The very high maximum scores in generations 97–100 occur as a result of the GA randomly introducing new individuals which violate one or more constraints. In each generation in Table 9.2, the minimum score indicates that all of the constraints are likely to have been met. It is likely that even the solutions in the first few generations with the minimum score meet all of the constraints. These candidates likely have a higher annual cost than the least cost solution because of unnecessary capacity. The GA finds new individuals with lower capacities, and hence lower costs, which still satisfy the constraints, and the formerly least cost candidate is replaced.

The simulations differentiate simulated generators by their region (eg, Victorian wind and South Australian wind). As the capital and O&M costs of each generator type is independent of location in this research, 1 MW of wind power in one region can be substituted for 1 MW of wind power in another region assuming similar capacity factors with little change in the annual costs. Hence, many different configurations can produce a system with similar costs.

The use of bioenergy, as noted, is contentious. It was observed that a 100% renewable electricity system can still be operated reliably using very small amounts of bioenergy (eg, 1 TWh-e per year). However, this results in a system with very high capacities of the remaining technologies and the costs are very high (they are approximately doubled). The contour of the evaluation function is not yet well understood and exploring it in more detail is likely to reveal further insights with policy implications.

[1] This point was also made by AEMO at a stakeholder forum the author attended for the 100% Renewables Study in Melbourne in May, 2013.

Generation no.	Minimum score	Maximum score
1	38.58	72.86
2	37.23	39.61
3	36.45	38.35
4	35.38	37.49
...	...	...
97	19.63	32.3×10^9
98	19.62	14.4×10^9
99	19.61	3.0×10^9
100	19.61	27.8×10^9

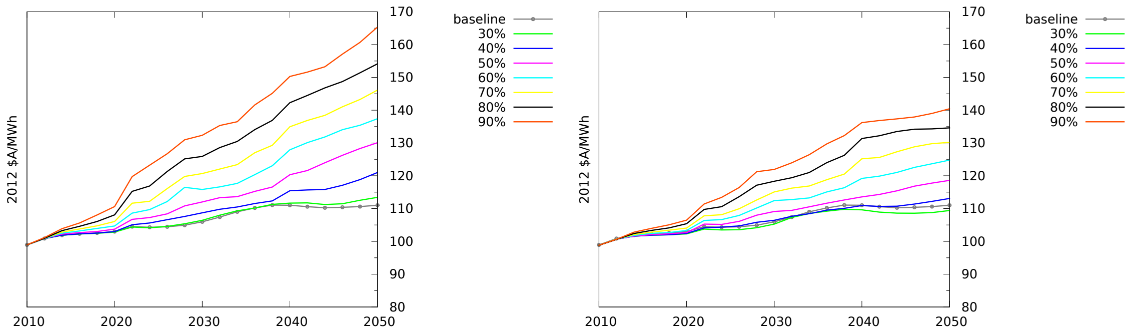
Table 9.2: Sample of scores from one GA run (in $ billion per year)

9.5 What about 90% renewables?

The 100% renewable electricity scenarios presented in this thesis may seem overzealous to some, but choosing 100% allows for a valuable examination of the operational issues for the limiting case and an upper bound on the costs. When I present this research, members of the audience often ask, 'Wouldn't 90% be a lot cheaper than 100%?' and, 'Isn't the last 10% really expensive?'. In the Australian context, this is an open question and could be examined more closely in the future (Section 10.1).

However, there is a special case in which the answer is likely to be, 'No' or at least, 'The difference in cost is negligible'. If the OCGTs are fuelled on fossil gas with a similar price to biofuels, then in the optimal mix situation, we could have a 93-94% renewable electricity system with the same cost as the 100% renewable system. If the gas price is slightly less than the biofuel price and the OCGTs contribute 10% of annual electricity generation, then the difference in cost between the 90% and 100% renewable system would be negligible.

The National Renewable Energy Laboratory (NREL) Renewable Electricity Futures Study (RE Futures) for the continental United States (Mai et al. 2012), reviewed in Chapter 3, gives some insight into the likely answer to this question in the general case. RE Futures examined a range of scenarios with different levels of RE penetrations. The penetration levels range from 30% to 90% with additional sensitivity analyses for the 80% case. Average retail electricity price trajectories



(a) RE-ITI scenarios

(b) RE-ETI scenarios

Figure 9.8: Average retail electricity price trajectory to 2050 for scenarios based on incremental and evolutionary technology improvement under a range of renewable electricity penetration levels. Data derived from Mai et al. (2012)

out to 2050 are shown for the ITI (incremental technology improvement) and ETI (evolutionary technology improvement) scenarios in Figure 9.8. The figures show that the incremental cost of increasing the renewables penetration from 80% to 90% is not markedly greater than the incremental cost of 70% to 80% in either the ITI or ETI scenarios. The costs increase steadily with growing penetration of RE.

This may be explained in the context of the present research. As the penetration of renewables grows towards 100% and renewable electricity displaces dispatchable fossil-fuelled generation, the capacity of dispatchable generation increases to address critical periods of low wind and solar generation. However, OCGTs are the lowest capital cost technology of the eligible technologies (around one order of magnitude lower cost than CST) and although OCGTs consume costly biofuel, they run sufficiently infrequently throughout the year that the cost impacts are small. Hence, it is expected that modelling renewable penetrations below 100% in the NEM would have similar cost implications as found by NREL in RE Futures.

9.6 Beyond scenario modelling

Some states and countries around the world have significant RE targets, and are making progress towards meeting them. As discussed in Chapter 2, Germany and Denmark are aggressively deploying renewable electricity as part of comprehensive long-term energy plans for the year 2050. A significant expansion of RE in South Australia has occurred due to the expanded Renewable Energy Target (eRET) and the South Australian target of 33% renewable electricity by 2020. In 2012-13, South Australia produced 30% of its annual electricity energy from RE with around 27% of annual generation from wind power (Pitt and Sherry 2013a). On summer days in December 2013 and January 2014, 15–20% of daily demand was routinely met by PV. On Christmas Day 2013, when demand was low, around 25% of electricity was supplied by PV (Australian Photovoltaic Institute 2014). The Northern power station is the only operational coal-fired power station in South Australia, and currently runs only during the summer months. However, the state relies substantially on imports of electricity from the neighbouring state of Victoria. At times, lower marginal cost coal-fired generation from Victoria displaces local, higher marginal cost gas-fired generation, moderating spot prices in South Australia. Moreover, because the interconnector exhibits similar operational characteristics to a flexible generator, it plays an important balancing role in South Australia. Recent experience in South Australia gives a glimpse into the way that the transition to 100% renewable electricity might begin: greater use of wind, solar PV and CST generation, declining use of imports and natural gas-fired gas turbines to balance the variable wind and PV generation, and the eventual elimination of coal-fired electricity.

Scenarios for 100% renewable electricity are necessary to examine system behaviour and economics of very high penetration systems well into the future. There is a need, however, for experimentation with working systems to gain operational experience, demonstrate that the system can work in practice, and to identify areas of research, particularly for controlling the power system on very short time scales.

The Kombikraftwerk project, or 'combined power plant' in English, originated at the Institute for Solar Energy Supply Systems at the University of Kassel in 2007 (Kombikraftwerk 2014). In conjunction with industry partners, the project demonstrated how a miniaturised generation fleet comprising solar PV, wind,

Figure 9.9: Kombikraftwerk 2 control room. Photograph courtesy Fraunhofer Institute for Wind Energy and Energy System Technology.

hydro and biogas generators operating in the field around Germany can meet 0.01% of German electricity demand and maintain power quality. Today, a renewed Kombikraftwerk 2 project (Figure 9.9) is operating in conjunction with the Fraunhofer Institute for Wind Energy and Energy System Technology and a larger consortium of industry partners, although published results are so far limited (Barnham et al. 2013).

9.7 Limitations

This section outlines some of the limitations identified during the research and proposes what could be done to overcome them. The limitations listed below are approximately ranked, with the most significant appearing first.

Simulating more years

The foremost task to improve the simulations is to increase the number of years simulated. Collecting a comprehensive set of high quality demand, generation and weather data over a common time frame has been limited by data availability, data quality, and time available for PhD research. The simulations use demand data and weather observations for a single recent year, 2010. Other international studies such as Rasmussen et al. (2012) for Europe and Allen et al. (2013) for the United Kingdom have used eight and 10 years of data for simulations, respectively. Simulations need to be carried out using weather data over a period that includes a range of extreme events. The results from this research would be strengthened if simulations could be performed over as many as ten years. Alternatively, a smaller number of years could be used in conjunction with probability distribution functions to meaningfully vary the demand and weather data.

Greater temporal and spatial resolution

The simulations have limited temporal and spatial resolution due to the lack of higher resolution data from all of the required sources. The simulations use hourly time steps and a coarse regional model of the generators and transmission network. Some generators (eg, PV and CST) are modelled at specific locations, other generators (eg, Victorian wind and Tasmanian hydro) are modelled at low spatial resolution. Increasing the spatial resolution of RE resource data will also be valuable in siting generation for geographic diversity. The simplified transmission network underestimates the full length of transmission lines required and therefore the cost of transmission. The polygon approach used by AEMO to divide the NEM into 43 regions is a good starting point. The simulations would be more incontrovertible if they were performed at higher spatial and sub-hourly temporal resolution.

Simulating forced outages

The model assumes ideal availability of generators and transmission networks. This assumption could be removed by incorporating typical forced outage rates and extending the model to maintain spinning and non-spinning reserve margins at all times. In the NEM, a Minimum Reserve Level (MRL) for each region is set based on available generation and interconnection in that region such that there is a high probability that the reliability standard will be met over a year

(Tamblyn et al. 2009). It should be possible to do this in the existing model by randomly choosing forced outages for each generator a priori. For the GA to function correctly, outages must be deterministic in every simulation run by the GA. The GA will ensure that sufficient capacity is available to satisfy the reliability standard.

Finding demand for surplus generation

Surplus renewable generation could be absorbed using simulated power-to-gas facilities (eg, hydrogen or synthetic methane production using the Sabatier process), as used in some scenarios (Henning and Palzer 2014; Palzer and Henning 2014; Allen et al. 2013; Lehmann 2003). The idea has also been examined by Troncoso and Newborough (2007). Synthetic gas could be stored as fuel for gas turbines. It would be necessary to examine the gas storage requirements and note how long gas must be stored before it is consumed. It is possible that power-to-gas could significantly reduce the demand for bioenergy in the present scenarios. Electric vehicle charging is another possible demand for surplus generation and could be easily simulated as a pseudo-generator.

Modelling operational details

Minimum operating levels, minimum start-up/shutdown times, ramp rates and percentage of synchronous generation could be included in the model so that challenging operating periods can be more closely examined. An important contribution made by the AEMO 100% Renewable Energy study was to model the levels of synchronous generation hour by hour to ensure that sufficient rotating inertia was available for AC frequency control. At these low levels, synchronous generators will need to be dispatched out of merit order, as is done in the AEMO study, or rotating inertia will need to be supplied from idle generators acting as synchronous condensers.

Central receiver CST systems

Central receiver CST technology was excluded at the start of the research in 2010 in favour of parabolic trough technology for which there is over 30 years of operational experience. With the recent construction and successful operation of CST power towers such as Gemasolar and Planta Solar 20 (PS20) in Spain, and the Ivanpah system in the United States in the intervening time, it is now reasonable to remove this restriction. AETA projects that central receiver systems with storage will have a slightly lower capital cost than parabolic troughs in 2030, and a markedly lower levelised cost of energy due to the higher thermal efficiency and capacity factor of central receiver systems.

Operating strategies for CST

The CST generator model in the present simulation tool uses a simple dispatch strategy. The generator is dispatched whenever there is sufficient demand and when it is able to generate. With a more sophisticated CST generator model, additional CST generators could be introduced into the simulations to serve as peaking plants. These generators could be dispatched using a more sophisticated strategy that examines other variables such as the season, time of day, instantaneous system demand, and thermal storage levels, to better contribute to meeting peak demand.

West-facing PV

In the present simulations, all solar PV capacity faces north. There is the potential to introduce PV generation oriented in other directions (eg, to the west) to improve the temporal diversity of PV generation, an idea proposed for these simulations by Burke (2014). It would be valuable to assess the contribution of PV systems to meeting peak loads in the optimal mix. Additional generation data for west-facing PV systems in each of the capital cities could be modelled using System Advisor Model (SAM). Additional PV generators could then be introduced into the simulations. The genetic algorithm can find their economically optimal contribution to the mix.

Simulating more dispersed wind and solar generation

Wind farm generation is based on historical aggregated wind farm output from existing wind farms in the NEM. Upon reflection, a better appreciation for the contributions of individual existing wind farms, correlated as they may be, would be insightful. This would require not aggregating the wind farm output and assigning one simulated wind farm to each actual wind farm.

Wind farms in additional locations such as northern Queensland could be modelled more accurately and introduced into the scenarios, as discussed in Chapter 8. The work presented in that chapter identified promising sites in northern Queensland which could increase the contribution from wind energy and reduce its variability, but higher resolution wind resource data (preferably anemometer data) is needed to realistically simulate the additional wind farms in a tool like SAM.

Similarly, the simulations are necessarily simplified with a small number of solar generators: six PV and six CST generators in specific locations as a consequence of the difficulty in producing good quality weather data files. This situation underestimates the potential reliability of the system that could be achieve by further dispersion of the solar generating sites.

Exploring the objective function contour

The contour of the objective function space in the GA is not well understood, as noted earlier in the chapter. Although a brute force search is computationally inefficient, the brute force approach taken by Budischak et al. (2013) guarantees that the global minimum will be found. By keeping the number of parameters small – five in the Budischak et al. (2013) paper – a brute force search of the entire parameter space is feasible. One way to do a brute force search of the least cost solution in the present scenarios is to reduce the number of parameters in the present 20-parameter space that are unlikely to significantly influence the results. For example, reducing the number of CST sites from six to one would not significantly alter the annual costs, but would produce one very high capacity CST generator and reduce the number of parameters to 15. A brute force search with a small number of parameters would be of interest in finding the global minimum and further validating the performance of the GA. This exploration could include the effect of lower penetrations of RE below 100%, as discussed in Section 9.5.

Demand response

In Section 9.3.5, it was mentioned that demand in a 100% renewable electricity system must become more flexible. Research presented in Chapter 5 demonstrated how effectively system reliability can be improved by reducing peak demands for a small number of hours. The economic analysis in the present research does not assume any modification in 2010 demand, but this assumption could be revisited in future research. The model could be extended, giving users a number of basic operations to modify the demand profile: uniformly scale the load (energy efficiency), move a fixed number of megawatts from one hour to another each day (load shifting), and reducing demand peaks (load shedding). Used in combination, these operations can modify the demand profile as the user desires. Furthermore, a simulated demand response generator could be introduced into the simulations that provides for load shedding as the generator of last resort. Like the other generators, it would be necessary to assign costs to this generator to avoid the GA using demand response to minimise the system cost to zero by removing all demand. Assigning costs to demand response is not straightforward. Some demand response measures have no capital cost, but opportunity costs (eg, deferring the running of an oven). Other measures have capital costs (eg, devices for remote load control of air conditioning). One approach that could be considered is the use of multiple demand response generators in the system with fixed capacities (eg, 500 MW) and different costs assigned. The latter 500 MW cut in demand could be modelled to have much higher variable costs than the first.

Transition paths

The scenarios presented in this thesis are end-points. The scenarios do not set out transition paths as other scenarios in the literature have. Transition paths are the missing element for the formation of a comprehensive energy policy. In a given time frame, a modelled pathway gives an appreciation for the required rate of deployment, the challenges of integrating moderate levels of RE into a less flexible fossil-fuelled system, and schedules for the 'premature' retirement of existing fossil-fuelled generation (leading to stranded assets). What will the role of existing generation be? Will some of the coal plants only run for some part of the day or part of the year? Could some of the existing OCGTs be retained as peaking plants and operate on renewable fuels?

Updated cost data

In December 2013 the Bureau of Resources and Energy Economics (BREE) released an update report for the AETA (Bureau of Resources and Energy Economics 2013a), although the full data are not yet available at the time of writing. The update outlines some revisited assumptions after consultation with industry and other parties. These revisions have generally reduced the costs of renewable technologies such as CST and wind power. Due to the timing of its release, the updated cost data could not be included in this thesis. BREE is to be commended for its efforts in continuing to revise the AETA data set. It is a valuable source of specific cost data for Australia and the author recommends that the data continue to be maintained as more experience with the installation and operation of RE is gained in Australia.

More recent estimates of the costs of the 100% renewable electricity scenarios could be obtained by updating the costs and re-running the model. It is expected that the new cost data would lower the annual costs. Relative changes in the costs of the different technologies evaluated in AETA may also alter the share of electricity generation from each technology. Possible future reductions in the cost of energy storage has important implications for the mix of technologies in 100%

RE systems and the degree of centralisation of the system. With cost-effective storage, it is speculated that the lower cost technologies, wind power and PV, will claim even larger shares of energy generation, displacing more expensive CST and bioenergy. Storage would enable PV penetration to be further increased, presently limited by its generation profile and the coincidence of generation with demand.

Emissions produced by the transition

In the short to medium term, the construction of renewable electricity generators will produce greenhouse gas emissions. A useful question which was not considered in the present research is how much greenhouse gas will be emitted during the transition to a 100% RE system? To have a 75% probability of limiting global average temperatures to 2°C, the world can emit a further 550 Gt of CO_2-e from 2014 to 2050 (Meinshausen et al. 2009). Should the emissions required for the transition to RE be pre-allocated from this carbon allowance? This is a complex question because the construction of renewable technologies, will emit less carbon as the emissions intensity of electricity reduces over time. The life cycle CO_2 emissions of a PV module, for example, are almost exclusively determined by the emissions embodied in the module during manufacture. As the emissions intensity of electricity at a PV manufacturing plant declines, so do the embodied emissions of the PV module.

Detailed power system modelling

To perform more detailed simulation of the scenarios produced in the Renewable Electricity Futures Study, Mai et al. (2012) used the GridView package in conjunction with the higher level Renewable Electricity Deployment Systems (ReEDS) modelling tool. The optimal mixes from Chapter 6 could be modelled using a tool like GridView to examine the operational issues of 100% renewable electricity, further validating the results.

Real-time simulations

Since the start of this research in 2010, Internet sites providing timely access to wind and solar PV generation data in the NEM have become increasingly available in Australia. Rather than simulating an historical year, it would be interesting to demonstrate the operation of a 100% renewable electricity scenario in near real-time using published generation data for existing renewable generators in the NEM and a set of additional hypothetical generators to meet the residual demand. This type of simulation, similar to Kombikraftwerk, could show how the residual demand would be met, possibly integrating solar and wind forecasts to operate the system. A visual representation of the system could be published on a website for public viewing.

9.8 Chapter summary

This chapter has reflected on the key insights from the research findings presented in Chapters 5 to 7. The AEMO study, published in July 2013, has also demonstrated the operational feasibility of 100% renewable electricity under a range of different input assumptions. This reinforces the point that there are many viable configurations of 100% renewable electricity that can achieve a reliable system. A new view of the operation of the electricity supply-demand system was presented in this chapter that places greater emphasis on demand side response and generator flexibility. Some of the myths about RE have been refuted, namely that RE has to provide baseload power, is intermittent, and produces unwanted energy that cannot be stored.

Chapter 10

Conclusion

Achieving 100% renewable electricity entails a radical 21st century re-conception of an electricity supply-demand system, already flagged in some of the studies in the literature. The focus is shifted away from replacing base load coal with alternative baseload sources. System reliability is maintained in a system with large penetrations of variable renewable sources by having as great a diversity of locations as possible, large capacities of peak-load generators, and storage. Additional reliability can be achieved by demand management at critical times in a 'smart' grid and by increasing the dispersion of wind and solar farms. In such a 100% renewable electricity system, the concept of a baseload power station is redundant.

This thesis demonstrates that, subject to the stated conservative assumptions, 100% renewable electricity could have supplied the demand of the Australian National Electricity Market in 2010 given the weather experienced in that year. The scenarios are restricted to technologies that are commercially available. There is no need to wait for other renewable energy (RE) technologies or carbon capture and storage (CCS) to become commercially available, in order to decarbonise the National Electricity Market (NEM). The simulations show how current RE technologies can be combined to form a generation mix for the NEM that maintains the same reliability standard as the existing fossil-fuelled system. The system does not require large amounts of battery storage, but relies on a small share of electricity from dispatchable NEM hydroelectric stations and biofuelled gas turbines, technologies with inherent storage. Concentrating solar thermal (CST) with storage also contributes to the reliability of the supply system. In the present scenarios, there is limited potential for storing surplus RE from wind and solar photovoltaic (PV) (eg, using pumped storage hydro). While affordable storage options could allow more electricity to be sourced from variable wind and solar generation, which is expected to be the lowest cost in 2050, they are not required to achieve system reliability. Arguments used against renewable generation, on the grounds that it is variable and uncertain, have been refuted. While not all of the details have yet been analysed, this work and studies like it are showing that these problems are not insurmountable.

Using a computationally efficient genetic algorithm, the economically optimal mix of 100% renewable electricity technologies has been found using a wide geographic area and a range of diverse generating technologies, capacities and locations that meet reliability and sustainability criteria. The optimal mixes are dominated by wind power, with smaller contributions from PV and CST. Hydroelectricity generation is limited by available rainfall, and the consumption of bioenergy is also constrained by the availability of biomass residues. Depending on economic assumptions, the 100% renewable system scenarios in 2030 are projected to cost between \$96 per MWh and \$154 per MWh. This represents an approximate doubling to tripling of the wholesale cost of generation today.

Upon testing three efficient fossil fuel scenarios with CCS under a range of plausible parameter values, the majority of cases do not compete economically with the 100% renewable scenarios. In some limited cases, the fossil fuel scenarios could be lower cost than the 100% renewables scenario. However, none of the fossil fuel scenarios achieves zero operational emissions as the 100% renewable electricity scenarios can because CCS plants cannot economically capture all emissions. The results suggest that without CCS, renewable electricity generation can be pursued at similar cost in the Australian context, at least. It is not necessary to wait for CCS technologies to emerge.

10.1 Further work

The further work generally entails overcoming the limitations identified in Section 9.7, which will give greater confidence in the results. This will also assist with identifying the grid integration challenges that more detailed modelling can reveal. The areas of further work include:

- increasing the number of simulated years;
- increasing the temporal and spatial resolution of the model;
- simulating generator and transmission network failures;
- simulating sources of demand for surplus generation such as electric vehicle charging, intermittent processes and various forms of storage, specifically 'power to gas' to produce renewable fuels for gas turbines;
- modelling finer operational details of the power system such as ramp rates and minimum operating levels;
- replacing parabolic trough CST systems with central receiver systems as a superior and potentially lower cost technology;
- creating a more sophisticated operating strategy for CST plants so that they may be operated more specifically as peaking plants;
- introducing a range of simulated PV generators that face west and a range of simulated wind farms in climatically diverse locations such as northern Queensland;
- exploring the objective function contour of the genetic algorithm to understand the nature of the set of solutions that meet all constraints;
- introducing simulated demand response (with and without associated costs);
- updating the cost data as new costs become available and evaluating the results;

- simulating the least cost mixes in a detailed power system model like GridView as was done in the Renewable Electricity Futures Study for the United States; and
- using real-time generation data from actual PV installations and wind farms to simulate a 100% renewable electricity system in near real-time.

10.2 Policy recommendations

The policy implications of the research are reasonably clear: subject to the stated limitations of the modelling, 100% renewable electricity using only commercially available technologies is operationally feasible and likely to be lower cost than CCS for deeply decarbonising the NEM. It is not necessary to wait for CCS technologies to emerge, which are still at the pilot stage. The research has considered decarbonising the single largest source of greenhouse gas emissions in Australia, electricity generation. The electricity sector is arguably the easiest to tackle. Manifold low carbon technologies are available and there is still significant scope for demand reduction. This thesis has not examined other sources of emissions in sectors which are likely to be much more difficult, namely agriculture, industrial processes, and transport (particularly aviation).

The transition to 100% renewable electricity requires a suite of policies and a different mix of policies is required for RE technologies at each stage of maturity. Research and development (R&D) policies to subsidise the development of nascent technologies (eg, hot dry rock geothermal power or large-scale batteries) have their place, but do not address the evolution of technologies that are more mature. Commercially available technologies need mainly policies to build the market, and those at demonstration stage require policies such as loan guarantees and low-interest finance to carry them through to commercialisation. Of course, R&D is needed at each stage, even for commercially mature technologies.

RE policy support to bring about a transition to 100% renewable electricity based on commercially available technologies could take the form of renewable portfolio standards (as currently implemented in Australia with modest targets) with banding to support RE technologies currently more expensive than wind; market-oriented feed-in tariffs; regulation of emissions of fossil-fuelled power plants; and carbon pricing. All of these policies can play a role in halting the construction of new fossil-fuelled power stations, making the current fossil-fuelled generation fleet pay at least part of the cost of greenhouse gas emissions, and bringing new renewable generation onto the grid.

The costs of commercially available renewable technologies are steadily declining, primarily as a result of manufacturing and installation experience in the large markets of Europe, China and the United States. As this thesis demonstrates, a range of technologies are required for a reliable 100% renewable electricity system. The least mature technology of those selected for the Australian scenarios described in this thesis is CST. Although this technology can be described as commercially available, the number of installations world-wide is small and the capital costs are still high. Support policies encouraging the diffusion of CST technologies or, more generally, technologies that are predictably dispatchable could potentially reduce the overall costs.

Community acceptance of RE is generally high in Australia. There is a very high level of public support for solar PV, a technology that many homeowners in Australia own outright and have installed on their own roof to silently generate electricity. However, wind power is more controversial due to small, vocal opposition groups with strong political connections. Community resistance is therefore a possible barrier to high penetrations of wind power in some localities.

This thesis shows that, subject to the stated assumptions, 100% renewable electricity could have reliably supplied the demand of the Australian National Electricity Market in 2010 given the weather experienced in that year. The scenarios are operationally feasible, reliable, and are likely to be affordable. The cost of the economically optimal mix of renewable technologies indicates that such a dramatic transformation of electricity generation in Australia would not be burdensome. The scenarios presented in this thesis are just one approach to decarbonising the electricity system based on legal, commercially available technologies in Australia. This option is likely to be lower cost than other low-carbon options, including efficient fossil fuelled systems employing CCS, and is the only option capable of zero operational emissions.

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