Analysis of institutional adaptability to redress electricity infrastructure vulnerability due to climate change

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The University of Queensland, University of Technology Sydney

12 June 2013

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Published by the National Climate Change Adaptation Research Facility

ISBN: TBC
NCCARF Publication TBC

Please cite this report as:
Foster, J, Bell, WP, Wild, P, Sharma, D, Sandu, S, Froome, C, Wagner, L, Misra, S, Bagia, R 2013, *Analysis of institutional adaptability to redress electricity infrastructure vulnerability due to climate change,* National Climate Change Adaptation Research Facility, Gold Coast, pp. 345.

Editor
Dr William Paul Bell, The University of Queensland

Acknowledgement
This work was carried out with financial support from the Australian Government (Department of Climate Change and Energy Efficiency) and the National Climate Change Adaptation Research Facility (NCCARF).

The role of NCCARF is to lead the research community in a national interdisciplinary effort to generate the information needed by decision-makers in government, business and in vulnerable sectors and communities to manage the risk of climate change impacts.

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Abbreviations

A1B	Balanced energy sources rapid economic growth SRES
A1FI	Fossil Intensive rapid economic growth SRES
A1T	Non-fossil energy sources
AAP	Australian Associated Press
ABC	Australian Broadcasting Corporation
ABS	Australian Bureau of Statistics
AC	Alternating Current
ACCC	Australian Competition and Consumer Commission
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ANEM	Australian National Electricity Market
APVA	Australian Photo Voltaic Association
ARENA	Australian Renewable Energy Agency
ASEFS	Australian Solar Energy Forecasting System
AWEFS	Australian Wind Energy Forecasting System
B1	Sustainable energy sources rapid economic growth
BAU	Business-As-Usual
BoM	Bureau of Metrology
BTEX	Benzene, Toluene, Ethyl-benzene and Xylene
CAES	Compressed Air Energy Storage
CCGT	Combined Cycle Gas Turbine
CCL	Climate Change LEvy
CCS	Carbon Capture and Storage
CDD	Cooling Degree Days
CEC	Californian Energy Commission
CER	Certified Emissions Reduction
CEO	Chief Executive Officer
CFL	Compact Fluorescent Lights
CHP	Combined heat and power
CIA	Central Intelligence Agency
CMIP	Coupled Model Intercomparison Project
CoAG	Council of Australian Governments
CPRS	Carbon Pollution Reduction Scheme
CSG	Coal Seam Gas

CSIRO	Commonwealth Scientific and Industrial Research Organisation
CSIRO-Mk3.5	GCM from the CSIRO used for the worst case (hottest) in this project
CST	Concentrated Solar Thermal
DC	Direct Current
DC OPF	Direct Current Optimal Power Flow
DSM	Demand Side Management
DRET	Department of Resources, Energy and Tourism
E3	Equipment Energy Efficiency
EEG	Erneuerbare-Energien-Gesetz (Germany's Renewable Energy Sources Act)
EV	Electrical Vehicle
Enel	*E*nte *N*azionale per l'*E*nergia e*L*ettrica
EPA	Environment Protection Agency
EPRI	Energy Power Research Institute
ESCO	Energy Services Companies
ETS	Emissions Trading Scheme
EUAA	Energy Users Association of Australia
FACTS	Flexible AC transmission systems
FFDI	Forest Fire Danger Index
GCM	Global Climate Model
GDP	Gross Domestic Product
GFC	Global Financial Crisis
GHG	Greenhouse Gas
GIS	Geographic Information System
GL	Gigalitre
GSP	Gross State Product
HDD	Heating Degree Days
HTS	High Temperature Superconductor
HVDC	High Voltage Direct Current
IEA	International Energy Association
IGCC	Integrated Gasification Combined Cycle
INL	Idaho National Laboratory
IPCC	Intergovernmental Panel on Climate Change
KEPCO	Korean Electric Power Corporation
KSGI	Korea Smart Grid Institute
kV	Kilovolts
LMP	Locational Marginal Pricing

LP	Linear Programming
LSE	Load Serving Entity
LTS	Low Temperature Superconductor
MCE	Ministerial Council on Energy
MEPS	Minimum Energy Performance Standards
MESSAGE	Model for Energy Supply Strategy Alternatives and their General Environmental impact
MRI	Meteorological Research Institute (Japan)
MRI-CGCM2.3.2	GCM from the MRI used for the most likely case in this project
MIROC3.2	GCM used for the best case (coolest) in this project
MRRT	Mineral Resource Rent Tax
NSP	Network Service Provider(s)
MUERI	Melbourne University Energy Research Institute
MVA	Megavoltamperes
MW	Megawatt
NBN	National Broadband Network
NCCARF	National Climate Change Adaption Research Foundation
NEM	National Electricity Market
NEMLink	A proposal to enable large-scale inter-regional power transfers
NEMMCO	National Electricity Market Management Company
NFEE	National Framework for Energy Efficiency
NGCC	Natural Gas Combined Cycle
NGCP	National Grid Corporation of the Philippines
NGF	National Generators Forum
NPV	Net Present Value
NSW	New South Wales
NT	Northern Territory
NWC	National Water Commission
NWI	National Water Initiative
OCGT	Open Cycle Gas Turbine
OECD	Organisation for Economic Co-operation and Development
PPP	Purchasing Power Parity
PRMSE	Percentage of RMSE
Prosumer	Producer and Consumer
PU	Per unit
PV	Photo Voltaic
R&D	Research & Development

REN21	Renewable Energy Policy Network of the 21^{st} century
RET	Renewable Energy Targets
RIT-T	Regulatory Investment Tests for Transmission
RMSE	Square root of the mean of the square of the error
RPA	Renewable Portfolio Agreement
SA	Southern Australia
SA2	Statistical Areas Level 2
SCQP	Strictly Convex Quadratic Programming
SEQ	South East Queensland
Series A	Higher growth ABS (2008) population projection
Series B	Most likely ABS (2008) population projection
Series C	Lower growth ABS (2008) population projection
Series I	Lower growth ABS (2010) number of households projection
Series II	Most likely ABS (2010) number of households projection
Series III	Higher growth ABS (2010) number of households projection
SGA	Smart Grid Australia
SGU	Small Generation Unit
SI	Standard International
SOE	State Owned Enterprise
SRES	Special Report on Emission Scenarios
STC	Standard Testing Conditions
SVC	Static var compensators
QLD	Queensland
QNI	QLD-NSW interconnector
TAS	Tasmania
TI	Transparency International
TNSP	Transmission Network Service Provider(s)
TOU	Time of Use
TOS	Time of Supply
UK	United Kingdom
US	United States
VIC	Victoria
VO&M	Variable Operation & Maintenance
VTT	Valtion Teknillinen Tutkimuskeskus
WA	Western Australia
WCRP	World Climate Research Program
WEC	World Energy Council

Acknowledgements

We thank Professor John Clarke and Dr Leanne Webb of the Tailored Project Services of the CSIRO Division of Marine and Atmospheric Research for the global climate projections developed specifically for the National Electricity Market (NEM) region and for constructive feedback on this book.

We thank Warwick Johnston of Sunwiz for his advice regarding solar PV.

We thank Lynette Molyneaux of UQ for numerous engaging discussions during the project, which helped crystallise many ideas expressed in this book.

We thank two anonymous reviewers for their profuse and constructive feedback during the development of this book.

We thank UniQuest for the coordination of the project amongst NCCARF, The University of Queensland (UQ) and the University of Technology, Sydney (UTS).

We thank the modelling groups, the Program for Climate Model Diagnosis and Inter-comparison (PCMDI) and the World Climate Research Program's (WCRP) Working Group on Coupled Modelling for their roles in making available the WCRP CMIP3 (Coupled Model Inter-comparison Project) multi-model dataset. Support of this dataset is provided by the Office of Science, US Government Department of Energy.

Preface

The project that culminated in this book came about as part of the Federal Government's recognition of the need for adaptation by human systems to address the physical changes induced by climate change. The Federal Government, through the Department of Climate Change and Energy Efficiency and the National Climate Change Adaptation Research Facility (NCCARF), funded this project.

There is a growing concern about the readiness of infrastructures in Australia both in adapting to and mitigating the effects of climate change. The electricity industry is vulnerable to the physical effects of climate change, including altered water availability on a seasonal or annual basis, changes to the incidence of extreme weather conditions such as storms, and changed average temperatures. This industry sector is also affected by policies directed to reducing its contribution to the chemical drivers of anthropogenic climate change (greenhouse gases or GHGs). For instance, the carbon intensive energy generation fleet is Australia's largest manmade cause of climate change. So, the electricity industry is faced with a significant challenge: to increase its resilience to climate change impacts while ceasing to be a major source of GHGs that contribute to climate change. This challenge requires consideration of (a) how greater climate resilience can be achieved while (b) transforming the generation portfolio from mostly fossil fuels to renewable energy sources or by employing cost effective carbon capturing technologies to offset the GHG emissions, created in the sector, until longer-term scalable practices are found. There has been a small, but gradual, improvement in the diversity of the generation portfolio with the increased penetration of solar PV and onshore wind generation.

This book provides many recommendations to ease the transformation of the electricity industry to one with greater climate resilience and a low carbon future. These recommendations entail significant structural changes. Indeed, structural change has been going on in the electricity sector for some time with impacts on those working in the sector. However, these changes for the most part are due to the perceived cost-effective advantages of privatised utilities over publically operated utilities rather than adaptation to climate change. The National Electricity Market (NEM) has undergone major restructuring over the last 20 years with the vertical separation of state monopolies into separate retail, distribution, transmission and generation components, as a prelude to deregulation and privatisation of these assets. This drive to privatise utilities has been an international phenomenon since the 1980s. However, the assumption that utility privatisation always delivers the best outcomes can be called into question from a number of directions:

- increasing inequity;
- inherent conflict between the profit maximising objectives of firms and climate change policy; and
- utility privatisations need not benefit the residential consumers.

Climate change increases the number of heat stress days, which increases financial or physical stress for lower income earners via increased electricity demand for air conditioning or non-use of air-conditioners, respectively. Additionally, there is the conflict of water usage during time of drought. Compounding these climate change induced stressors for low income earners, there is the looming privatisation of the electricity sector in Australia. The United States (US) has been the leading proponent of deregulation and privatisation. Yet it has experienced a large increase in income inequity (Weinberg 1996) to such an extent that there has been a 4% decline in the real mean incomes received by the lowest quintile of families from 1970 to 2011 (US Census Bureau 2013). Privatising the remainder of the electricity sector in Australia will move Australia closer to the socioeconomic structure of the US (Alvaredo et al. 2013).

Privatisation of utilities has only provided, at best, modest gains for the residential consumer. However, within the industry there has been a major transfer of wealth from employees to management. The result in the US has been to exacerbate the hardship of low income earners who are more susceptible to stresses induced by climate change. Seen from a wider economic and social perspective, privatisation of utilities per se has not been a success.

In addition, there is the inherent conflict between profit maximisation by companies and climate change policy. Placing a price on carbon has gone some way to address this conflict but the shift from a fixed carbon price aka carbon tax to a flexible carbon price aka emissions trading scheme (ETS), is detrimental to adaptation to climate change because the shift to an ETS introduces a new source of uncertainty. This ETS induced uncertainty amplifies the risk in making investment decisions for new generation plant hence delaying investment decisions, so stalling adaptation to climate change. The ETS also makes government revenue more uncertain, which curtails the government's ability to support innovation and commercialisation policies to foster adaptation to climate change.

There are additional adjustments required to be made to price signals to enable demand side management (DSM) such as the introduction of time of use (TOU) billing and time of supply (TOS) payments for non-scheduled generators. TOU and TOS payments together provide appropriate price signals for the diffusion of energy storage technologies such as batteries into the NEM. The deployment of energy storage addresses two issues: intermittency and non-dispatchability, both associated with renewable energy such as solar PV and wind generation. Addressing these two issues allow greater cuts in fossil fuel generator GHG emissions to mitigate climate change. The eventual deployment of electric vehicles (EVs) with their large battery storage, could aid DSM if the appropriate TOU and TOS price signals are in place. Without these price signals, EVs will exacerbate the existing peak demand problem in the NEM. There is a further inherent conflict between profit maximising network service providers (NSP) and climate change policy, in the way profits are calculated as rate of return on capital expenditure. This calculation is at odds with DSM and is discussed further in this book.

The Global Financial Crisis (GFC) has put to rest the concept that private ownership of utilities provides innately superior outcomes to government ownership with the US government effectively nationalising major parts of its economy to prevent economic collapse (Quiggin 2010). A more circumspect approach is to decide which parts of the economy should operate within the private or public sectors and this tends to change over time. So, the simplistic view that privatising the entire economy will take Australia to some economic optimum state is contrary to the evidence. In Victorian Britain, the private sector dominated in all aspects of production with limited regulation. The result was poor working conditions for the majority of the population and many negative externalities imposed upon the natural environment and social conditions. By the early 20th century, the government had introduced regulatory structures to improve this situation that would eventually result in the 'mixed economy' striking a balance between public and private ownership, which is the norm in advanced countries at present. We argue that this kind of 'regulatory maturity' is now required in both the electricity and energy sector more widely.

The approach in this book is to apply evidence based policy rather than policy based evidence. The latter approach relies on assuming the correctness of ideas or theories and finding evidence to support them. This approach has its appeal, of course, since reality is messy and difficult to interpret and there is always the issue of data accuracy and availability to test ideas or theories.

From an historical perspective, the legacy of federation of Australia was to have a national regulatory and monopoly telecommunications system but separate state regulatory and state monopoly electrical systems. At the time of Federation, this decision seemed appropriate as the state based electricity systems were isolated islands. Of course, this is no longer the case. In contrast, South Korea has had a national monopoly transmission and distribution system since its occupation by the Japanese who saw the advantages in reduced coordination costs from amalgamating the NSPs. And, of course, they had the power to enforce an amalgamation. The South Korean national monopoly transmission and distribution company now serves 50 million people. In contrast, Australia has more than 15 distributions and transmission companies which serve less than 23 million people. The tumultuous history of Korea has resulted in an exceedingly simple socioeconomic structure that has allowed it to develop the most reliable electricity system in the world, even with few natural resources available domestically. In contrast, Australia is resources rich, which allows Australia to sustain an unnecessary and inefficient duplication of regulatory regimes and excessive coordination overheads adding to GHG emissions and so detrimentally contributing to accelerated climate change. Additionally, the relatively tranquil political history of Australia has provided little motivation for rationalising the national transmission and distribution systems. However, climate change impacts and mitigation issues and the political backlash over the recent rapid increase in electricity prices, mainly stemming from NSPs, may provide the catalyst for significant restructuring of these systems. In this book, we explore the stresses that are building up in the national energy system and in its core, the NEM, and offer a greater understanding of the options that are available to correct this deteriorating situation to better adapt to climate change.

Professor John Foster
The University of Queensland

A non-technical summary for policy makers

John Foster and William Paul Bell, The University of Queensland

This non-technical summary presents the findings and recommendations from the project called *'Analysis of institutional adaptability to redress electricity infrastructure vulnerability due to climate change'*. The objectives of the project are to examine the adaptive capacity of existing institutional arrangements in the National Electricity Market (NEM) to existing and predicted climate change conditions. Specifically the project:

- identifies climate change adaptation issues in the NEM;
- analyses climate change impacts on reliability in the NEM under alternative climate change scenarios to 2030, particularly what adaptation strategies the power generation and supply network infrastructure will need; and
- assesses the robustness of the institutional arrangements that supports effective adaptation.

The project finds that four factors are hindering or required for adaptation to climate change:

1. fragmentation of the NEM, both politically and economically;
2. accelerated deterioration of the transmission and distribution infrastructure due to climate change requiring the deployment of technology to defer investment in transmission and distribution;
3. lacking mechanisms to develop a diversified portfolio of generation technology and energy sources to reduce supply risk; and
4. failure to model and treat the NEM as a national node based entity rather than state based.

The project's findings are primarily to address climate change issues but if these four factors are addressed, the resilience of the NEM is improved to handle other adverse contingences. For instance, the two factors driving the largest increases in electricity prices are investment in transmission and distribution and fossil fuel prices. Peak demand drives the investment in transmission and distribution but peak demand is only for a relatively short period. Exacerbating this effect is increasing underutilisation of transmission and distribution driven by both solar photo voltaic (PV) uptake and climate change. Using demand side management (DSM) to shift demand to outside peak periods provides one method to defer investment in transmission and distribution. Recommendation 2 addresses investment deferment.

The commodity boom has increased both price and price volatility of fossil fuels where the lack of diversity in generation makes electricity prices very sensitive to fossil fuel prices and disruptions in supply. A diversified portfolio of generation would ameliorate the price sensitivity and supply disruptions. Furthermore, long term electricity price rises are likely to ensue as the fossil fuels become depleted. A diversified portfolio of generation would also ready the NEM for this contingency. Recommendation 3 addresses diversified portfolios.

This project makes four inter-related recommendations to address the four factors listed above. Chapter 10 discusses the justification for these recommendations in more detail.

Recommendations to address four mal-adaptations to climate change

1 Institutional fragmentation, both economically and politically

The research in Chapter 9, using an international comparison, found major political and economic fragmentation in the NEM hindering adaptation of climate change. Therefore, it is recommended that the transmission and distribution lines of the NEM be placed in one company and the State Governments in the NEM cede legislative power over all electrical matters to the Federal Government. This would assist climate change adaptation by easing the deployment of renewable generation to mitigate GHG emissions and contain costs, as discussed further in Chapter 10. This could be achieved by the Federal Government retaining a controlling interest in the lines monopoly company and managing the electricity market with the existing Australian Energy Market Commission (AEMC), Australian Energy Market Operator (AEMO) and Australian Energy Regulator (AER). The same lines monopoly company own and manage the gas pipe line infrastructure to coordinate the use of the two energy sources via power-to-gas and tri-generation.

2 Distorted transmission and distribution investment deferment mechanisms

The research in Chapters 6 and 9 finds both the rapid rise in electricity prices over the last few years, mainly induced by NSPs building more infrastructures and the lack of progress in the NEM with implementing demand side management (DSM), need addressing. It is recommended that mechanisms to defer investment require both demand side management (DSM) and alignment of the business objectives, of the network service providers (NSP), with DSM. This would assist climate change adaptation directly by moderating the demand in electricity and the ensuing GHGs and indirectly by deferring investment in further distribution and transmission infrastructure. This could be achieved by DSM having both educational and incentive aspects. Incentives include price signals such as time of use (TOU) billing and time of supply (TOS) payments for non-scheduled generators. TOU and TOS payments together provide appropriate price signals for the diffusion of energy storage technologies such as batteries into the NEM. TOU and TOS require a national smart meter rollout with in-house display and devices to automatically switch off air conditioners during critical peak periods if the customer wishes to save on critical peak pricing; thus, reducing GHG emissions and slowing the rate of climate change. A single monopoly NSP reduces coordination costs and enables monopoly buying power for smart meters. Addressing poverty will aid acceptance of smart meters. Addressing energy poverty requires policies to target the misaligned benefits in the landlord-tenant relationship, emanating from energy efficiency equipment, solar PV or tri-generation. Policies include subsidising loans to encourage landlords to install such equipment, splitting the benefit of the equipment and introducing loss of capital tax free gains for non-compliant landlords.

The current remuneration for NSP is based on capital expenditure, so encourages the building of more network infrastructures which is at odds with DSM. To address this problem, it is recommended to include a business objective for the NSP to increase utilisation of exiting network infrastructure. Multiple business objectives are more easily handled by government owned enterprises.

3 Lacking mechanisms to develop a diversified energy portfolio

From our research and from international experiences, the current practices and structures in Australia provide little incentive for transforming energy generation from fossil fuels to renewables. It is recommended that the government change policy to introduce renewable energy targets for specific generation technologies as they become ready for commercialisation with designated timeframes. In conjunction, the use of feed-in tariff reverse auctions to cost effectively diversify the energy portfolio is recommended. By nationalising the retail sector, conflict of interest in dual retail-generator companies will be removed and the risk in forming power purchase agreements will be minimised. It is also recommended to streamline the grid connection process for distributed energy generators. These changes would assist climate change adaptation in the sector by cost effectively introducing renewable energy. Chapter 10 discusses these changes in more detail.

4 Failure to model and to treat the NEM as a national node based entity rather than state based

Our research found a requirement to improve electricity demand forecasts. To address this requirement, AEMO should produce node based half hourly data for scheduled and non-scheduled generation by node and provide Geographic Information System (GIS) files of the distribution areas. This would assist climate change adaptation as it would improve the ability to plan and make more climate resilient investments. There is variation in each node's expected population growth, climate change, weather and demand and supply response to changes in environment. Failing to acknowledge these differences could misinform policy. Introducing node based price signals would promote more appropriate investment decisions required in Recommendation 2. Recommendation 1 would help transform the NEM's focus from state to a national node basis and thus enable more coordinated climate change adaptation by maximising the use of the renewable resources across the NEM.

1. INTRODUCTION

John Foster and William Paul Bell, The University of Queensland

This book presents the research finding from the project tilted *'Analysis of institutional adaptability to redress electricity infrastructure vulnerability due to climate change'*. The objectives of this project are to examine the adaptive capacity of existing institutional arrangements in the National Electricity Market (NEM) to existing and predicted climate change conditions. The project aims are to:

- identify climate change adaptation issues in the NEM;
- analyse climate change impacts on reliability in the NEM under alternative climate change scenarios to 2030, particularly what adaptation strategies will the power generation and supply network infrastructure need; and
- assess the robustness of the institutional arrangements that support effective adaptation.

The main motivation stems from the development of existing institutional arrangements under the premise of stable climate conditions. Environmental issues, such as drought and increased climate variability have been largely overlooked and the recent past has demonstrated that this premise is no longer appropriate. The Government's policy response has been varied and somewhat uncoordinated, which has the potential to compromise the reliability of the NEM. In support of this observation, Ford et al. (2011) make a systematic review of the observed climate change adaption in developed countries using a meta search of the literature and find comparatively limited reporting from Australia. There is a need to redress this situation with the final conclusion from this project highlighting possible ways forward.

This project finds a need to adapt to climate change and builds on the arguments in Garnaut (2008) and Yates and Mendis (2009) that accurate prediction of climate change is fraught with uncertainty but there is scientific consensus that climate change is highly probable and the cost of not proactively adapting to climate change is high.

Institutional arrangements in the context of this project refer to structure, ownership and regulations where structure includes market operations, market design, spot pool and market trading. Ownership includes public versus private and regulations include pricing.

The findings of the project are delivered via three routes:

1. industry briefings to key stakeholders such as the Australian Energy Market Operator (AEMO), the National Climate Change Adaptation Research Facility (NCCARF), the Department of Climate Change and generator and distribution entities;
2. presentation and publication of the research at international conferences and in respected peer reviewed journals; and
3. final report to NCCARF of the Department of Climate Change, with a set of recommendations that will assist the Australian energy policy makers and key industry stakeholders to improve the capacity of the NEM to adapt to climate change.

In addition, the decision support tools developed as part of the project are available on request to industry and other stakeholders for further analysis.

This book builds on the first report of the project titled '*Analysis of institutional adaptability to redress electricity infrastructure vulnerability due to climate change*' to present the literature review and research finding in a consolidated form. Table 1-1 Correspondence between literature review and research chapters in this book relates the literature review and research chapters as well as the institution of the principal investigator leading each of the forthcoming reports.

Table 1-1 Correspondence between literature review and research chapters in this book

Principal Investigators' Institution	Chapter Title	Literature Review	Research
UQ	Selecting emission and climate change scenarios	2	3
UQ	The impact of climate change on electricity demand	4	5
UQ	The impact of climate change on electricity generation capacity and transmission networks	6	7
UTS	Analysing the effects of changes in water availability on electricity demand-supply	8	
UQ	Assessing the current institutional arrangements for the development of electricity infrastructure to inform more flexible arrangements for effective adaptation	9	

Chapters 2, 4, 6, 8 and 9 provide an extensive literature review to identify those areas where key research overlaps. Some studies have been performed to understand the risks associated with climate change, for instance Yates and Mendis (2009), however, the literature relating to Australia's electricity supply interests are significantly under-developed. Specifically, this review considers three key points:

1. the potential impacts of more variable climate conditions on the electricity industry;
2. the effectiveness of adaptation actions being carried out in the NEM and the potential for maladaptation (Barnett & O'Neill 2010); and
3. the flow-on effects of climate change impact and maladaptation (Barnett & O'Neill 2010) actions in other linked infrastructure industries such as water.

The review in Chapters 2, 4, 6, 8 and 9 provide focus and informs the research in Chapters 3, 5, 7, 8 and 9, respectively.

Yates and Mendis (2009, p. x) note that climate change affects multiple units and functions of the electricity infrastructure, so a systematic approach is required to identify vulnerabilities and maladaptation in the infrastructure to formulate a climate

change adaption strategic plan. Furthermore, they recommend that any plan must be embedded into the various units and functions rather than overlayed.
The review finds that four factors are hindering or are required for adaption to climate change:

1. fragmentation of the NEM both politically and economically;
2. accelerated deterioration of the transmission and distribution infrastructure due to climate change requiring the deployment of technology to defer investment in transmission and distribution;
3. lacking mechanisms to develop a diversified portfolio of generation technologies and energy sources to reduce supply risk; and
4. failure to model and to treat the NEM as a national node based entity rather than state based.

These first three factors are interrelated, for instance, the fragmentation of the NEM has hindered the deployment of technologies to allow deferment of investment in transmission and distribution. The investment in transmission and distribution is primarily driven by peak demand, which could be mitigated with smart meters, flexible retail tariffs and consumer engagement. On the supply side, the Renewable Energy Targets (RET) scheme has primarily driven onshore wind and solar photo voltaic (PV) uptake to the detriment of a broader portfolio. The onshore wind and solar PV each have their intermittent supply cycles that present a challenge to matching supply and demand. A broader portfolio of generation technology, storage and energy sources could both mitigate the intermittent supply cycles and aid deferment in transmission and distribution investment. However, promoting a broader portfolio of renewable energy would require modifications to the existing policy to incorporate targets for specific technologies and energy resources.

The fragmentation of the NEM has been acknowledged through the formation of a number of bodies to address coordination issues including, the Ministerial Council on Energy (MCE), Australian Energy Market Commission (AEMC), Australian Energy Market Operator (AEMO) and the Australian Energy Regulator (AER). However the underlying fragmentation and induced coordination problem still remains. Politically the NEM covers five states and one territory and their legislative requirements. Economically the NEM has thirteen distribution companies and six transmission companies. In contrast, South Korea, with two and half times the population of Australia, has a single company running both transmission and distribution within a single legislative entity. However, it must be acknowledged that South Korea covers an area smaller than the NEM region. A single company, Telstra, manages the entire copper based telecommunications network for the whole of Australia, which covers a much larger area than the NEM. Hence the NEM's region covering a larger area than South Korea is a poor justification for fragmentation. South Korea's adaption to climate change is more advanced than the NEM because South Korea lacks the political and economic coordination overhead of the NEM. The research questions in Section 4 include an international comparison to test this fragmentation observation.

The linking of the once separate state transmission and distribution networks to form the NEM's network has transformed the once natural monopoly within each state into a single NEM wide natural monopoly. So, the legacy fragmentation of the NEM's network causes coordination problems, which are a source of maladaptation to climate change. In contrast, retail and generation are more amenable to numerous companies competing, so the fragmentation brings these markets closer to perfect competition to derive benefits for consumers. However the state ownership of transmission, distribution, generation and retail provides a conflict of interest for companies installing new generation to attach to the state owned networks to compete with the state owned generators. This conflict of interest is an impediment to the development of a broad portfolio of generation technology and energy sources. Both the NEM's transmission and distribution network fragmentation and the conflict of interest cause maladaptation to climate change.

1.1 Chapter outline

Chapter 2 reviews the global climate models, emission scenarios and recent weather years for Australia. The chapter also discusses the projected change in temperature, solar radiation, wind speed, relative humidity, rainfall and sea level, temperature and acidity to 2030.

The research in Chapter 3 calculates the financial year with the highest maximum mean temperature and most volatile temperature for the baseline weather year for the NEM for the project. Chapter 3 also selects the most suitable Global Climate Model (GCM) and emission scenario for the project.

Chapter 4 reviews the effect of climate change on electricity demand and changing trends in demand. The review discusses short and long term drivers of electricity demand to inform the development of a model of demand in Chapter 5. Chapter 4 also reviews demand issues such as the increases in air conditions driving further investment in network infrastructure.

The research in Chapter 5 uses the GCM and baseline weather year selected in Chapter 3 provides half hourly demand projections from 2009-10 to 2030-31 for each of the 50 nodes on the NEM . These demand projections are used in Chapter 7. The demand modelling considers and is motivated by the recent poor demand forecasting in the NEM. The chapter investigates non-scheduled generation, as the AEMO demand figures only represent scheduled and semi-scheduled generation, so really are a form of net demand. Adding in non-scheduled generation produces a gross demand.

Chapter 6 reviews the literature on the effect of climate change on generation and transmission. First, reviewing the effect on existing technologies and then technologies more suited to addressing climate change. Discussing the need to improve resilience through a portfolio of energy sources and addressing intermittence issue of renewable energy. The research in Chapter 7 uses the demand profiles from Chapter 5 to find the change from 2009 to 2030 in four factors; carbon emissions, line congestion, generator type and the wholesale spot market price for electricity.

Chapter 8 reviews effect of the change in water availability on electricity demand, generation and transmission and presents original research.

Chapter 9 reviews the literature to assess the readiness of the institutional structure of the NEM. This Chapter particularly helps identify the four sources of maladaptation to climate change and compares the NEM's structure to those countries that have made more progress in adaption.

Chapter 10 discusses and draws together the findings of the research in Chapters 3, 5, 7, 9 and 11 and the literature reviews in Chapters 2, 4, 6, 8 and 10 to make recommendations to address the four sources of maladaptation to climate change. These recommendations are presented in the non-technical summary in the preface without discussion. Chapter 11 concludes the book by relating the non-technical summary to the discussion in Chapter 10.

2. SELECTING EMISSION AND CLIMATE CHANGE SCENARIOS: REVIEW

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The University of Queensland

This chapter discusses the expected climate changes within the scope of the project, which is till 2030.

This project uses climate change projections that are based on the standard *Global Climate Models* (GCMs) and on the standard *Special Report on Emissions Scenarios* (SRESs) (Nakićenović & Swart 2000) used in the Fourth Assessment Report of the *Intergovernmental Panel on Climate Change* (IPCC 2007a). OzClim (CSIRO 2011; Page & Jones 2001) and '*Climate change in Australia*' (CSIRO 2007b) provide national projections optimised for the whole of Australia based on these GCMs and SRES. This report uses the '*Climate change Australia*' (CSIRO 2007b) national projections to discuss climate change. However, the Tailored Project Services of the CSIRO Division of Marine and Atmospheric Research (Clarke & Webb 2011) has provided projections tailored to the NEM's region, for use in the forthcoming research reports.

This chapter discusses the selection of weather profile year, SRES and GCM for this project's baseline and discusses projections of change to environment variables to inform the remainder of this report in the following sections.

2.1 Projecting change in temperature using SRESs and GCMs

The Intergovernmental Panel on Climate Change (IPCC) (2007a) forms projections of climate change using 23 GCMs based on six carbon emission scenarios called SRESs. These six SRESs are grouped into four families. Table 2-1 shows the four SRESs families called A1, A2, B1 and B2, which are the permutation of two sets of foci: economic or environmental and globalisation or regionalism. Additionally, the SRES called A1 has three variants, which represent different technological emphasis: fossil-intensive (A1FI), non-fossil energy sources (A1T) or a balance across all sources (A1B) respectively.

Table 2-1 The four 'Special Report on Emissions Scenario' families

	Economic focus	Environmental focus
Globalisation	**A1** Rapid economic growth (Variants **A1T, A1B, A1FI**)	**B1** Global environmental sustainability
Regionalism	**A2** Regional orientated economic development	**B2** Local environmental sustainability

(Source: IPCC 2007b)

Table 2-2 shows the projected global surface warming at the end of the 21st century from a baselines year 1990 for the six SRESs. The projected surface temperatures best estimate and likely range are derived from using the 23 GCMs for each SRES. The A1FI provides the worst case hottest scenario and closest to a non-adaptive or business as usual scenario.

Table 2-2 The six SRESs & projected global average surface warming from 1990 to 2100

Case	Best estimate	Likely range
Constant year 2000 CO_2 concentrations	0.6	0.3-0.9
B1	1.8	1.1-2.9
A1T	2.4	1.4-3.8
B2	2.4	1.4-3.8
A1B	2.8	1.7-4.4
A2	3.4	2.0-5.4
A1FI	4.0	2.4-6.4

(Source: IPCC 2007b, p. 13)

2.2 Selecting among the GCMs and SRESs for this project

In a similar way to the IPCC, the Commonwealth Scientific and Industrial Research Organisation (CSIRO) uses 23 GCMs to provide a best estimate and 10th and 90th percentiles for each environment variables in Table 2-3 for the six SRES. These climate change projection are not forecasts but possible futures conditional on the input data or SRES and GCM (CSIRO 2007b, p. 112). Combining the results of various GCMs is suitable for providing a best estimate and uncertainty measure for individual climate change variables. But, if these environment variable projections from different GCMs are combined, the result is an internally inconsistent climate change scenario (CSIRO 2007b, p. 144; Manning et al. 2010), as environment variables are not independent variables. However, the best estimate and likely range for individual climate change variable projections for each SRES are suitable for a general discussion about each variable in isolation.

Table 2-3 Comparing environment variables used in climate change studies

Typical studies (Yates & Mendis 2009, p. 17)	Climate change in Australia (CSIRO 2007b)	This project
Temperature	✓	✓
Rainfall	✓	✓
Extreme weather events		
Solar radiation	✓	✓
Relative humidity	✓	✓
Wind	✓	✓
Snow		*
Sea level rise	✓	*
Ocean temperature	✓	*
Ocean acidity		*
	Key: ✓ = modelled	* = discussion only

An unconstrained approach to solving this internal consistency conundrum would be to analysis the NEM using all six SRESs and all 23 GCMs, which makes for 118 analyses and then combine the results. But a more judicious approach is to focus on the purpose of the project that is maladaptation to climate change to select among the SRESs and GCMs.

The SRES A1FI is selected for this project for the following four reasons:

- There is a great deal of uncertainty about climate change where assigning a probability to each of the SRES merely disguises the distinction between subjective and objective probabilities to allow the use of probability theory.

- In the event of severe climate change the consequences of maladaptation could be high (CSIRO 2007b, p. 108; Garnaut 2008, pp. 96, 9), so there is justification for using the worst case SRES A1FI.

- Given the long half-life of CO_2 in the atmosphere, much of the current stock of CO_2 in the atmosphere will remain in the atmosphere for the 20 year scope of this project, which makes projections of the GCMs fairly insensitive to SRES choice till 2030 (CSIRO 2007b, p. 45).

    - CSIRO (2007b Appendix A and supplementary material) projections for temperature, relative humidity, solar radiation, rainfall and mean wind speed show that GCMs are fairly insensitive to SRES choice for the NEM region to the year 2030.
    - Reisinger (2010, pp. 68-7) states that the emissions of each scenario differs substantially but the choice of SRES whether B1, A1B, or A2 has little effect on temperature until after 2030. *"The reason for this similarity is that about half of the warming over the next two decades is due to greenhouse gas emissions that have already occurred, but the atmosphere is still adjusting to the change in energy balance that has been caused by these past emissions. This adjustment takes decades and, for some processes, even centuries."*

- To date the net global effort to address climate change most closely resembles the A1FI scenario that is business as usual or non-adaptive scenario.

So, the best SRES for this project is A1FI. However, there are still 23 GCMs to select among. The Tailored Project Services section of the CSIRO Division of Marine and Atmospheric Research (Clarke & Webb 2011) selected the GCM called MRI-CGCM2.3.2 as best representing the *Most Likely* projection of the 23 models conditional on the geographic region of the NEM, on the SRES being A1FI, and on the required environment variables in Table 2-3. Using this single GCM to represent the *Most Likely* projection of the 23 models produces an internally consistent projection of the *Most Likely* case. The GCMs called CSIRO-Mk3.5 and MIROC3.2 provide internally consistent projections of the *Worst Case* (hottest) and *Best Case* (coolest), respectively. Appendix A discusses the GCM selection process in more detail.

2.3 Distinguishing between a weather profile and a climate change baseline

A further consideration is that the natural variability in weather from year to year is likely to be greater than the change in climate over the 20 year duration of this project, which has positive and negative consequence for modelling. The positive consequence is that the uncertainly from the selection of GCM and SRES is eclipsed by the consequences of selecting an inappropriate weather profile year for the baseline year of this project. A distinction requires to be made between the concepts of a weather profile year for the baseline year of this project and a baseline year for a climate change projection. The climate change projections are given relative to the period 1980-1999, which is referred to as the 1990 baseline for convenience (CSIRO

2007a). So the climate change projections are synonymous with a 20 year moving average whereas this project selects the weather profile of a particular year for a baseline and incrementally adjusts the weather profile with climate change projection data. This approach has the advantage of using realistic internally consistent weather data for the project's baseline year and the data being adjusted by internally consistent climate change increments to form a projection.

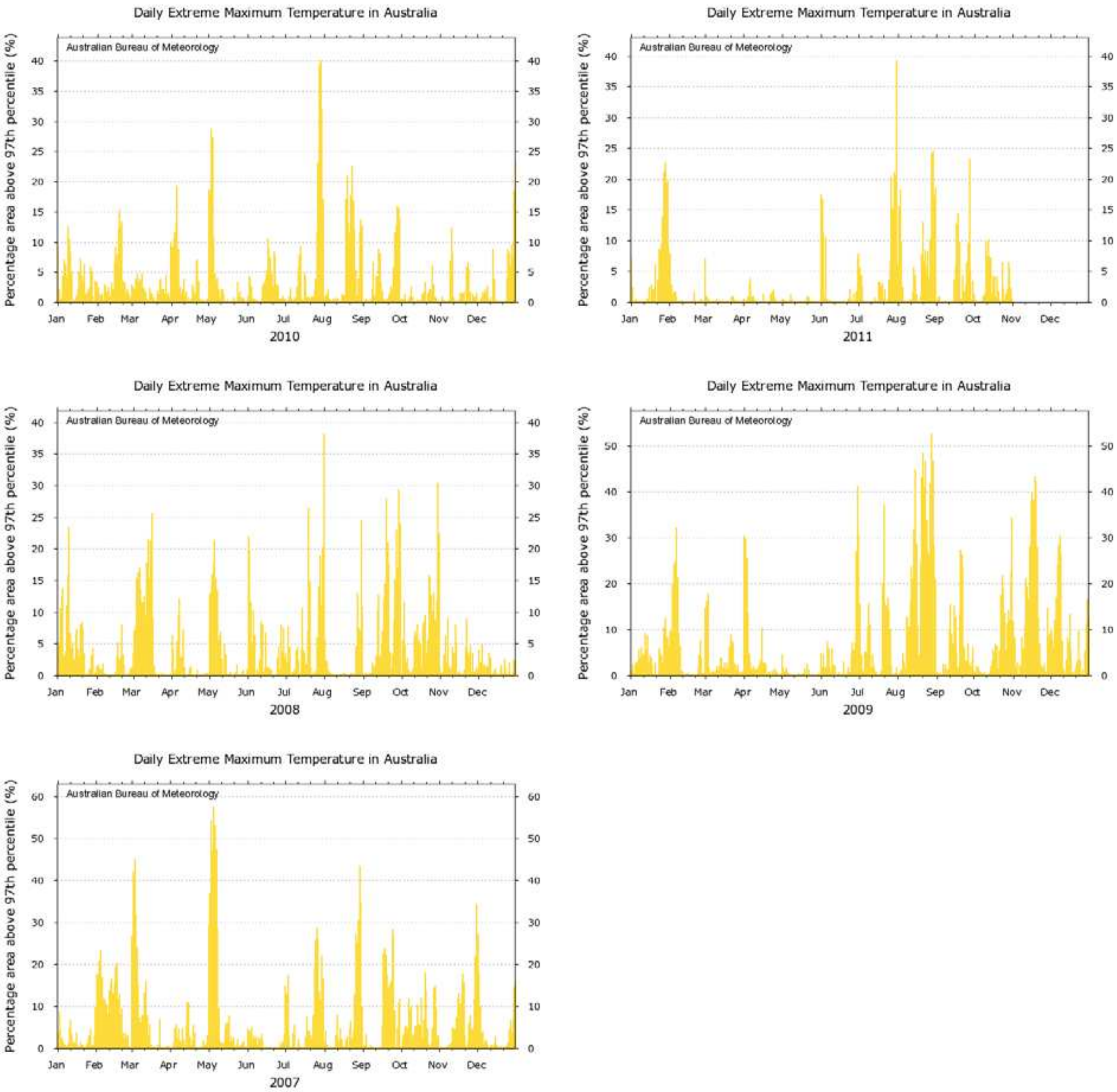
Garnaut (2008, p. 41) and Yates and Mendis (2009, p. 7) discuss and contrast a change in temperature mean with a change in variance for future climates. This project's mean incrementing without change in variance comes with the caveat that the relationship among the environment variables is stable over the duration of the projection. This caveat is not too onerous a requirement as the project's projection period of 20 years is relatively short for a climate change projection.

Furthermore the selection of a weather profile year for this project's baseline will require the comparison among the weather of a number of years to ensure a suitably volatile year is selected to test the resilience of the NEM. This selection is constrained to fairly recent years to model contemporary weather patterns.

2.4 Selecting a weather profile year for this project's baseline

As the natural weather variability from year to year may be higher than the climate change over the 20 years, there is great importance in selecting a weather profile year for the baseline year that tests the NEM. So, this section discusses the selection of a weather profile year for the project based on three criteria. First is that the year is relatively recent so as to model a contemporary weather pattern, hence the selection is made among the years 2007 to 2011. Second is that the year exhibits frequent extreme maximum temperatures, so as to test the resilience of the NEM to contend with volatility in temperature. Third is that the year exhibits higher mean temperatures, to test the resilience of the NEM to contend with consistently higher than normal temperature. The Bureau of Metrology (BoM 2011a) provides graphical and statistical data on extreme weather events for the years 2007 to 2011.

Figure 2-1 A comparison of daily extreme maximum temperature from 2008 to 2011

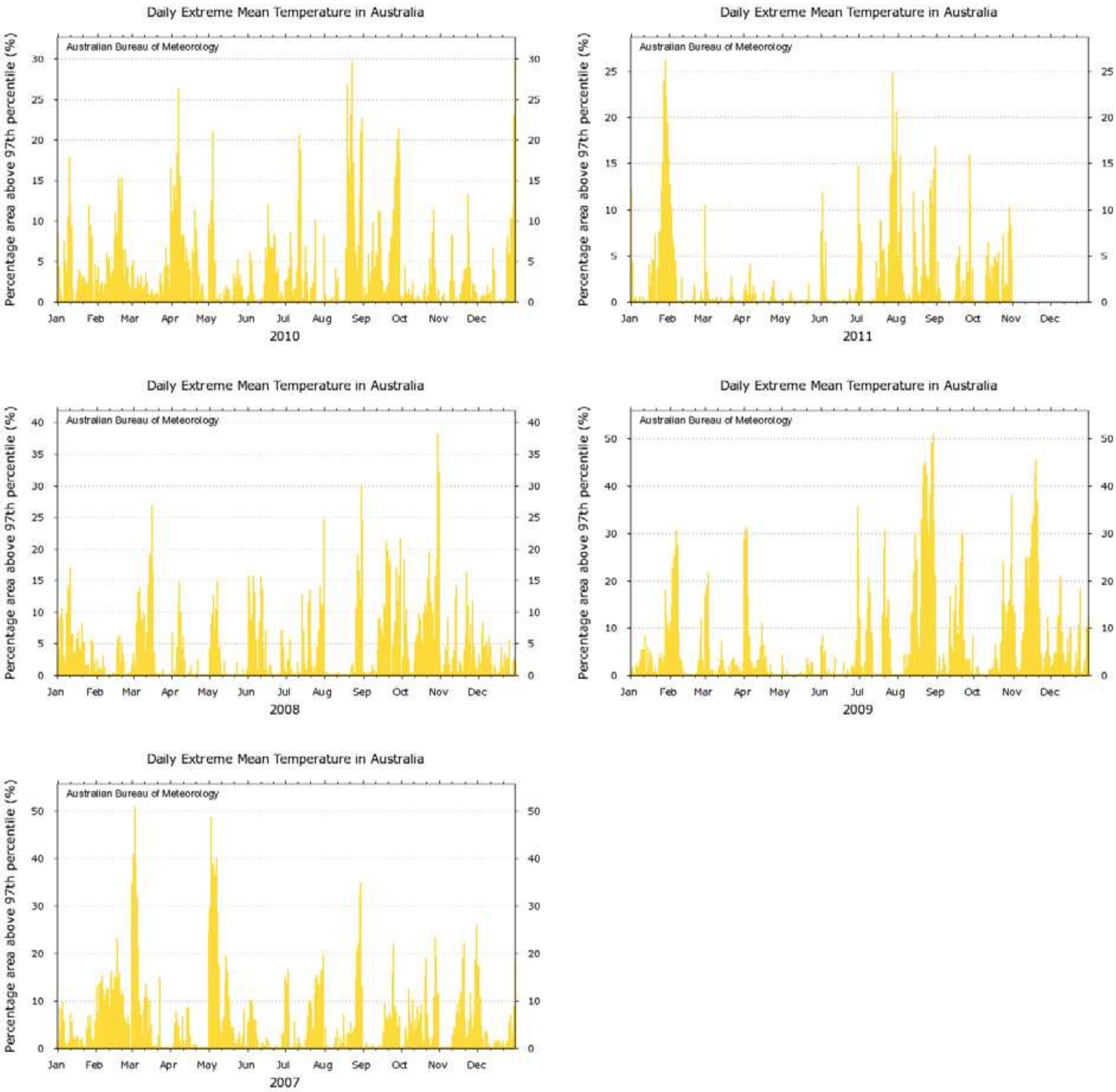


(Source: BoM 2011a)

Figure 2-1 shows that the year 2009 has the highest frequency of maximum temperatures above the 97th percentile but year 2007 provides the most extreme weather.

Figure 2-2 compares the daily mean temperature above the 97th percentile in Australia for the years 2007 to 2011 where the years 2009 and 2007 again show the highest frequency of mean temperatures above the 97th percentile. Both the mean and maximum results suggest that years 2009 or 2007 are satisfactory weather profile years for the project's baseline. However, this analysis is for the whole of Australia and a closer analysis of the weather for the NEM that is excluding Northern Territory (NT) and Western Australia (WA) could affect this result. Additionally, the weather statistics for the year 2011 are incomplete at the time of writing, which could also affect this result. So, a fuller analysis left until after 2011 may provide an alternative weather profile year for the project's baseline. Furthermore, Section 2.11 discusses an extreme weather event in 2007 that caused a major disruption to the NEM in Victoria (VIC), which could make 2007 a particularly good weather profile year for this project.

Figure 2-2 A comparison of daily extreme mean temperature from 2008 to 2011



(Source: BoM 2011a)

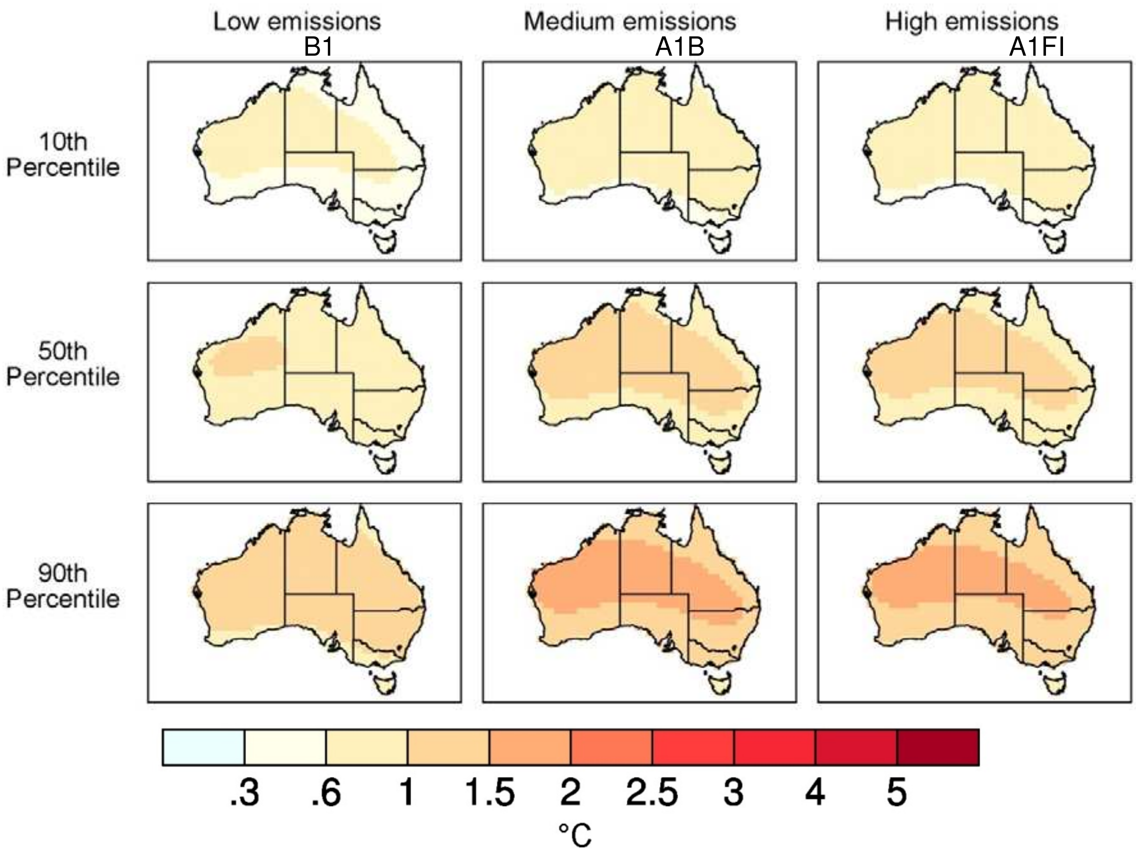
The following sections discuss the climate change projections of the environmental variables in Table 2-3. The projections are given relative to the 1990 baseline. These projections provide an estimate of the average climate around 2030 and take into account consistency among climate models. The *most likely* case or 50th percentile is the mid-point of the spread of model results and provides a best estimate result. The *best* and *worst case* or 10th and 90th percentiles are the lowest 10% and highest 10% of the spread of model results and provide a range of uncertainty. The low, medium and high emissions scenarios are the SRES called B1, A1B and A1FI respectively (CSIRO 2007a). The projections in this project use the high emission scenario A1FI.

2.5 Projected change in temperature from 1990 to 2030

"The best estimate of annual warming over Australia by 2030 relative to the climate of 1990 is approximately 1.0ºC, with warmings of around 0.7-0.9ºC in coastal areas and 1-1.2ºC inland. Mean warming in winter is a little less than in the other seasons, as low as 0.5ºC in the far south. The range of uncertainty is about 0.6ºC to 1.5ºC in each season for most of Australia. These warmings are based on the A1B emission scenario, but allowing for emission scenario uncertainty expands the range only slightly - warming is still at least 0.4ºC in all regions and can be as large as 1.8ºC in some inland regions. Natural variability in decadal temperatures is small relative to these projected warmings." (CSIRO 2007b, p. 9)

Figure 2-3 shows that climate change induced temperature increases are greatest in Western Australia and the inland areas. In comparison the highly populated region of the NEM best corresponds with the less affected coastal region. In the high emissions scenario A1FI and worst case (90th percentile) temperature increases by between *1.0ºC* and *1.5ºC* while in the most likely case (50th percentile) the temperature increases by between *0.6ºC* and *1.0ºC.* Noteworthy is that the medium emissions scenario A1B looks very similar to the high emissions scenario A1FI, which shows model insensitivity to these scenarios until the year 2030.

Figure 2-3 Predicted national annual temperature change from a 1990 baseline to 2030



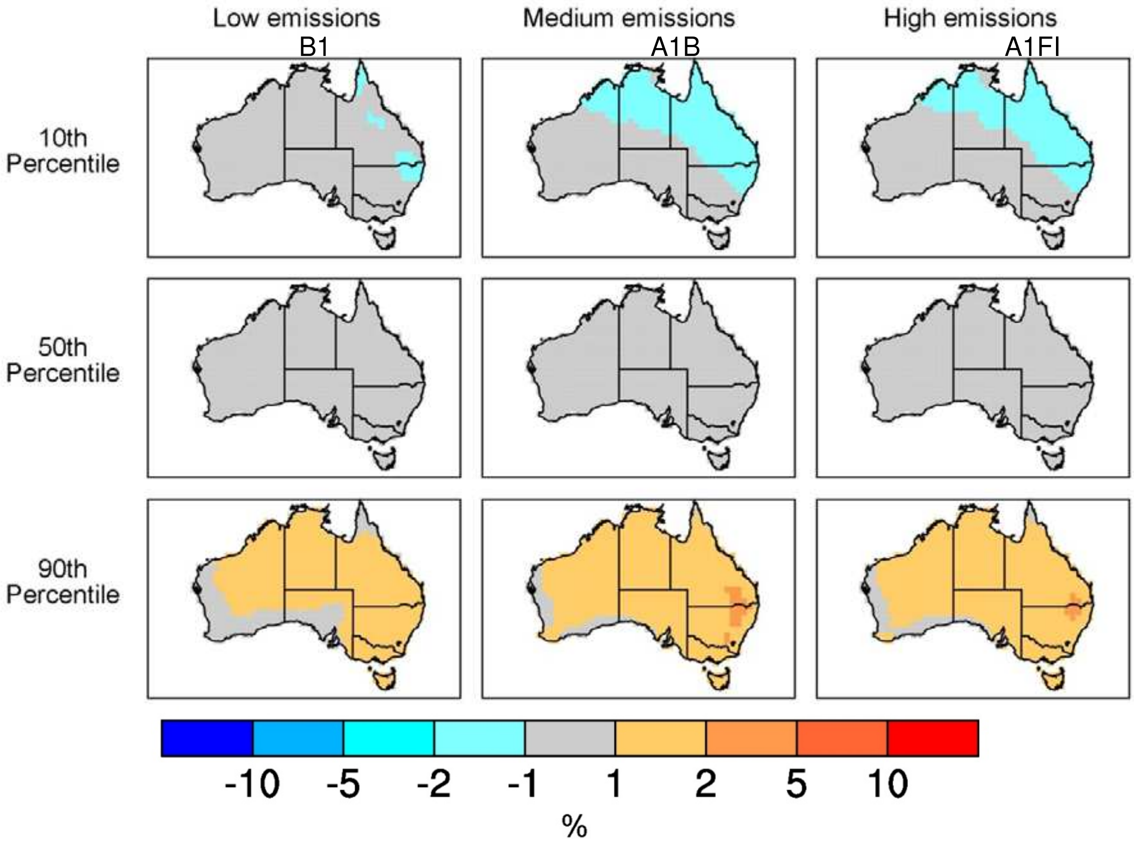
(Source: CSIRO 2007b)

2.6 Projected change in downward solar radiation from 1990 to 2030

"Projections of solar radiation generally show little change although a tendency for increases in southern areas of Australia is evident, particularly in winter and spring. The projected range of change is typically -1% to +2% in 2030." (CSIRO 2007b, p. 11)

Figure 2-4 shows the projected change in downward solar radiation from 1990 to 2030. Noteworthy is that there is little difference among the three SRES. Additionally, in the most likely case (50th percentile) there will be little to no change expected in downward solar radiation. In the worst case (90th percentile) there is a one to two percentage increase, which could increase the output of solar generators but this increase becomes uncertain when taken in conjunction with an increase in temperature seen in Figure 2-3. In contrast, in the best case (10th percentile) there is a decrease in solar energy of 1 to 2 per cent for most of Queensland (QLD) and north eastern New South Wales (NSW), which would reduce the output from solar generators. This reduction is amplified when taken in conjunction with the projected increase in temperature seen in Figure 2-3. So, there is good reason to study the best case scenario (10th percentile) when considering this reduction in power from solar generators for the effect on the NEM. In contrast, the increase in temperature will increase the efficiency of solar thermal hot water systems and the overall efficiency of hybrid solar PV/thermal systems.

Figure 2-4 Predicted annual solar radiation change from a 1990 baseline to 2030



(Source: CSIRO 2007b)

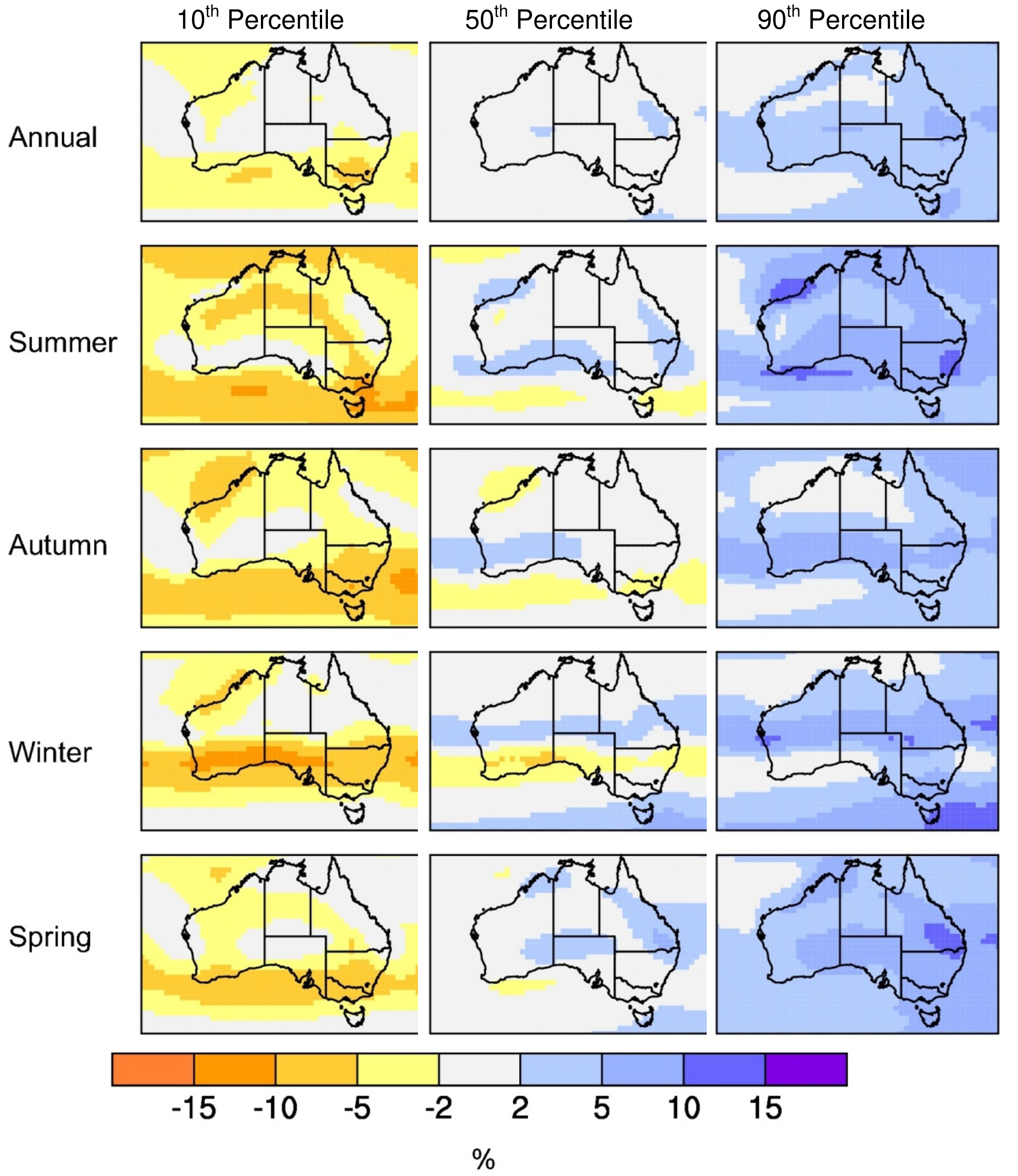
2.7 Projected change in wind speed from 1990 to 2030 by season

"There is a tendency for increased wind speed in most coastal areas in 2030 (range of -2.5% to +7.5% with best estimates of +2% to +5%) except for the band around latitude 30°S in winter and 40°S in summer where there are decreases (-7.5% to +2.0%, with best estimates of -2% to -5%)." (CSIRO 2007b, p. 11)

Figure 2-5 shows the projected change in wind speed from 1990 to 2030 for the medium emission scenario that is SRES A1B. The wind projection for the SRES scenarios A1B and A1FI are nearly identical, which shows the GCMs are insensitive to these two scenarios until 2030. The change in wind speed shows considerable seasonal variation in contrast to the change in temperature and downward solar radiation discusses in sections 2.5 and 2.6 respectively.

In the most likely case (50th percentile), Figure 2-5 shows a distinct seasonal pattern where a latitudinal band of decreased wind speed moves from Tasmania (TAS) in summer, to VIC in autumn, to NSW and South Australia (SA) in winter where the band dissipates in spring. In tandem in winter two bands of increased wind speed appear in the latitudes about south QLD and TAS, which also dissipate in spring. In the Worst case (90th percentile) wind speed increases across the NEM, this would provide wind generators with more output. However, in the best case (10th percentile) wind speed across the NEM decreases, which would reduce the output for wind generators. So, there is good reason to study the best case scenario (10th percentile) when considering this reduction in power from wind generators for the effect on the NEM.

Figure 2-5 Predicted seasonal wind speed change from 1990 to 2030 for SRES A1B



(Source: CSIRO 2007b)

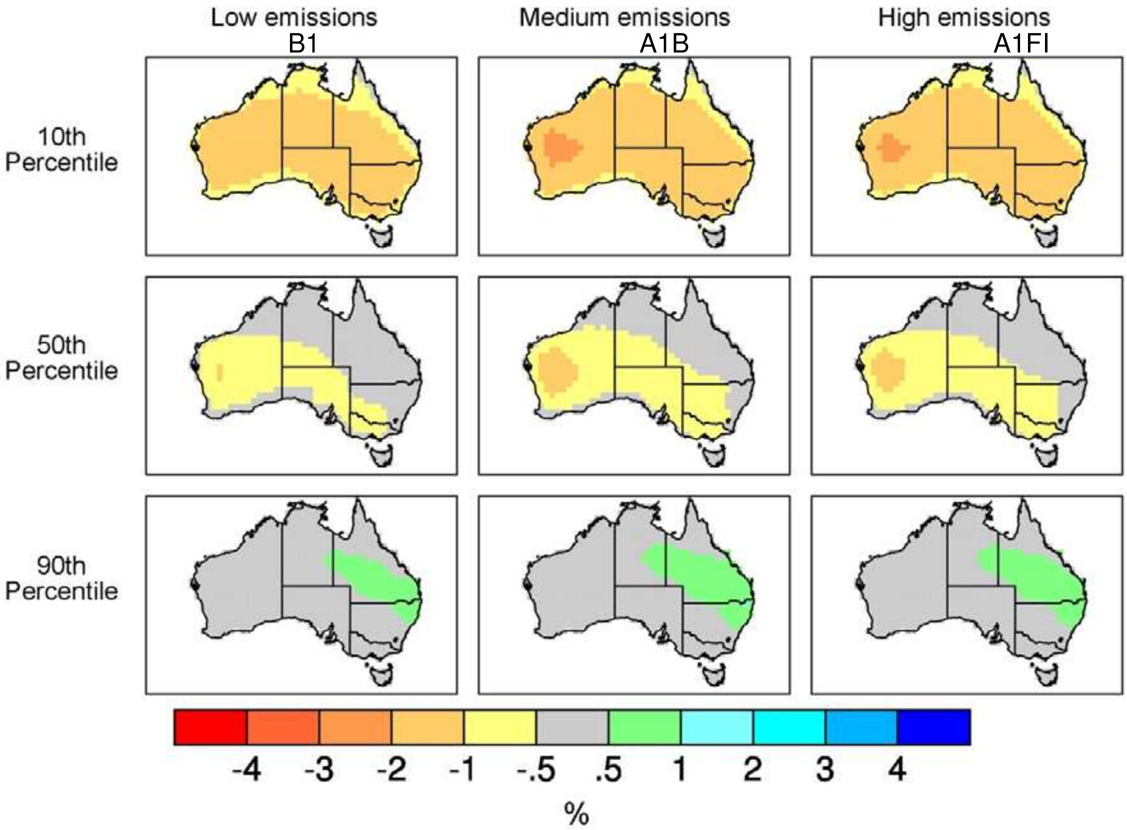
2.8 Projected change in relative humidity from 1990 to 2030

"Small decreases in relative humidity are projected over most of Australia. The range of change in annual humidity by 2030 is around -2% to +0.5% with a best estimate of around a 1% decline." (CSIRO 2007b, p. 11)

Figure 2-6 shows the projected change in relative humidity from 1990 to 2030. Noteworthy is that there is little difference among the three SRES. Most likely (50th percentile) the NEM will experience a 0.5% to 1% reduction in humidity in Southern Australia and VIC and inland NSW. In the best case (10th percentile) the NEM less TAS will experience a 0.5% to 2% reduction. In the worst case (90th percentile) southern QLD and north eastern NSW will experience a 0.5% to 1% increases in humidity. The annual presentation in Figure 2-6 hides a significant seasonal variation in the change in humidity from 1990 to 2030.

The reduction in humidity is significant because this decrease could partially offset the increase use of air conditioners induced by an increase in temperature seen in Figure 2-3. Chapter 4 further discusses this potential offset.

Figure 2-6 Predicted change in relative humidity from a 1990 baseline to 2030



(Source: CSIRO 2007b)

2.9 Projected change in rainfall from 1990 to 2030

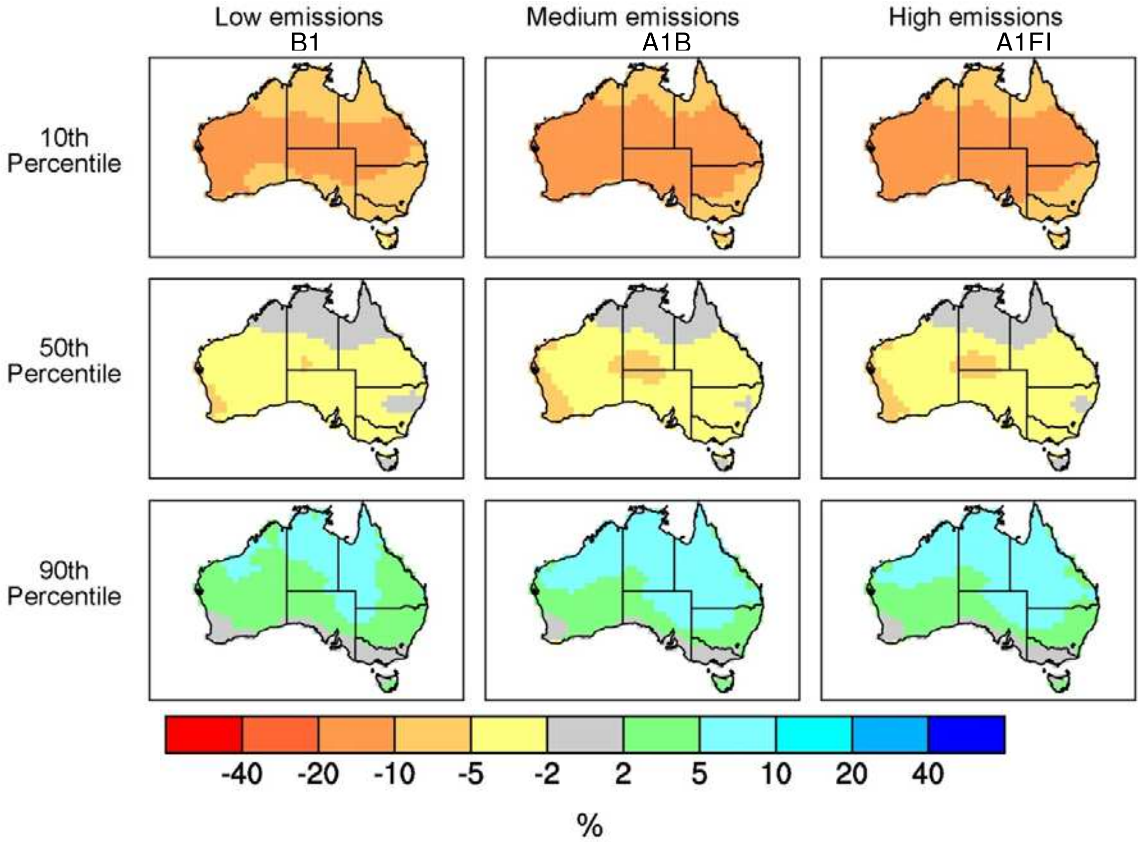
"Best estimates of annual precipitation indicate little change in the far north and decreases of 2% to 5% elsewhere. Decreases of around 5% prevail in winter and spring, particularly in the south-west where they reach 10%. In summer and autumn decreases are smaller and there are slight increases in the east.

The range of precipitation change in 2030 allowing for model-to-model differences is large. Annually averaged, the range is around -10% to +5% in northern areas and -10% to little change in southern areas. Decreases in rainfall are thus more consistently indicated for southern areas compared to northern areas. Winter and spring changes range from decreases of around 10% to little change in southern areas of the south-east of the continent, decreases of 15% to little change in the south-west, and decreases of around 15% to possible increases of 5% in eastern areas. In summer and autumn, the range is typically -15% to +10%. Decadal-scale natural variability in *precipitation is comparable in magnitude to these projected changes and may therefore mask, or significantly enhance, the greenhouse-forced changes."* (CSIRO 2007b, p. 10)

Figure 2-7 shows the projected change in rainfall from 1990 to 2030. Again there is little difference among the three SRES. Most likely (50th percentile) the NEM less TAS and a small part of NSW will experience a 2% to 5% reduction in rainfall. In the best case (10th percentile) Queensland and South Australia will experience a 10% to 20% reduction and NSW and VIC will experience a 5% to 10% reduction. In the worst case (90th percentile) there is significant variation in change across the NEM: VIC between -2% and 2% change, QLD a 5% to 10% increase, NSW a 2% to 5% increase, SA between -2% and 10% change, and TAS between -2 and 5% change.

The most likely reduction in rainfall is significant in reduced water availability for thermal generator cooling and for hydro generation. Chapter 8 further discusses the effect of change of water supply on electricity demand and supply.

Figure 2-7 Predicted change in rainfall from a 1990 baseline to 2030



(Source: CSIRO 2007b)

2.10 Projected change in sea level, temperature and acidity

The change in sea level, temperature and acidity are significant for the NEM in undermining the concrete footing of poles and pylons and causing accelerated corrosion of infrastructure when taken in conjunction with the projected increases in wind speed.

"By 2030 the best estimate of sea surface temperature rise is 0.6-0.9ºC in the southern Tasman Sea and off the north-west shelf of Western Australia and 0.3-0.6ºC elsewhere. Allowing for model-to-model variations, the ranges are 0.4-1.4ºC in the southern Tasman Sea and 0.4-1.0ºC off the north-west coast." (CSIRO 2007b, p. 12)

The increase in sea surface temperature acts to reduce the sea's absorption of atmospheric CO_2 but this effect is overwhelm by increases in atmospheric CO_2 driving the sea's absorption of CO_2 to increase ocean acidity.

"Increases in ocean acidity are expected in the Australian region with the largest increases in the high- to mid-latitudes. Under-saturation of aragonite could occur by the middle of the century in the higher latitudes, affecting the capacity for shell and endoskeleton creation by marine organisms." (CSIRO 2007b, p. 12)

The wellbeing of marine organisms with shells or endoskeleton is beyond the scope of this project but the NEM and these marine organisms share a common problem in calcium carbonate dissolving under more acidic conditions.

"Global sea level rise is projected by the IPCC to be 18-59 cm by 2100, with a possible additional contribution from ice sheets of 10 to 20 cm. However, further ice sheet contributions, that cannot be quantified at this time, may substantially increase the upper limit of sea level rise." (CSIRO 2007b, p. 11)

The rise in sea level in conjunction with extreme wind conditions provides two problems for the NEM. First is the increase in direct flooding of infrastructure in coastal areas. Second is the wider dispersion of sea spray inland. Both problems are compounded by the projected increases in seawater acidity. This acidity is further exacerbated by increases in air and sea temperature, which makes acids more reactive.

It is not only generators that are at risk of flooding from rising sea levels and inland floods. Due to the nature of the electricity infrastructure electricity substations are very often located at lower points than generators with little or no thought given as to their vulnerability to flooding. In the United Kingdom (UK) 2007 floods the main substations at Waltham and Castle Mead came within inches of being flooded and triggering a massive black out across the grid in Gloucestershire and South Wales which may have also triggered other impacts on the rest of the national grid (Flood Probe 2011). This was only prevented by the building of an emergency dam just in time by emergency services and the military. Subsequently, mitigation measures using permanent or temporary defences or elevating or relocating substations was undertaken. A similar event occurred at the main substation at Reading in the UK 2012 floods. Section 6.1 further discusses flooding and sea spray acidity.

The next section further discusses the interrelatedness of extreme weather events to cause problems for the NEM.

2.11 Extreme weather events

Yates and Mendis (2009, p. 11) claim that the term extreme weather event is unhelpful as the term lumps together many different environmental variables, which makes detailed cause and effect analysis impractical, so this project avoids the term unless the specific environmental variables are identified. For instance bushfires are one such extreme weather event caused by a combination of environmental conditions.

Lucas et al. (2007) use a Forest Fire Danger Index (FFDI) to estimate the degree of danger of fire in southeast Australia, which coincides with most of the NEM's region.

The index combines, rainfall, evaporation, wind speed, temperature and humidity data to provide six fire danger categories shown in Table 2-4.

Table 2-4 Fire danger rating

Category	Fire Danger Index
Catastrophic	100+
Extreme	75 - 100
Severe	50 – 75
Very high	25 - 50
High	12 - 25
Low to moderate	0 - 12

The rating of 100 is calibrated against the conditions prevalent during the Black Friday fire of 1939. Lucas et al. (2007) project that the number of 'very high' and 'extreme' fire danger days in south east Australia could increase by 4-25% by 2020 and by 15-70% by 2050. This presents an increased fire risk to the NEM's infrastructure. Additionally, the heatwave associated with fire risk stresses electrical components. For instance O'Keefe (2009) reports on a major blackout in VIC cutting off electricity to half a million homes and business caused by an explosion at an electrical substation in South Morang during a weeklong heatwave. In response to this event, the MCE ordered the AEMC (AEMC 2009, p. xvii) to review the effectiveness of the NEM's security and reliability arrangements to extreme weather events (AEMC 2010). Chapters 6 and 10 further discusses the review (AEMC 2010) and extreme weather events.

The transmission and distribution network is not only particularly susceptible to bush fires they can also cause bush fires as happened in the 2009 Victorian Bushfires (Victorian Government 2011).

2.12 Conclusion

This chapter has identified suitable climate change projections for the project, which consists of the following components:

- carbon emission scenario SRES A1FI;
- GCMs:
  - Most likely case – MRI-CGCM2.3.2
  - Worst case (hottest) – CSIRO-Mk3.5
  - Best case (coolest) – MIROC3.2
- environment variables:
  - temperature;
  - solar radiation;
  - relative humidity;
  - wind speed; and
  - rainfall;
- suitable weather profile year for the baseline of this project:
  - calendar year 2007 or 2009.

This Chapter has discussed the projected change in the environment variables to inform the remainder of the project. However the project uses financial years rather than calendar years to align analysis with legislative changes. Additionally, time constraints forced the selection of one GCM rather than use the desirable option to use three GCMs. The selection of GCM and baseline weather year is made in Chapter 3.

3. SELECTING EMISSION AND CLIMATE CHANGE SCENARIOS: RESEARCH

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This chapter selects the Global Climate Model (GCM) and financial year for the baseline weather year for the project. Chapter 2 presents three GCM as suitable for NEM Region. Ideally, three GCM would be used but time constraints force the choice of one GCM. Additionally, Chapter 2 identifies the calendar year with the highest average mean temperature and highest temperature volatility for Australia. However, this preliminary investigation has two shortcomings:

- the project uses financial year to allow easier analysis of legal changes that usually come into force at the beginning of financial years; and
- the projects scope is the NEM not the whole of Australia.

This chapter address these shortcomings and the time constraint issue with the following research questions:

1. *Which is the most suitable year for the projects baseline weather year?*
2. *Which global climate model and emissions scenario combination is most suitable for the project?*

The climate change parameters relevant to this chapter are repeated below for the convenience of the reader:

- carbon emission scenario SRES A1FI;
- GCMs:
    - Most likely case - MRI-CGCM2.3.2
    - Worst case (hottest) - CSIRO-Mk3.5
    - Best case (coolest) – MIROC3.2
- weather profile year for the baseline of this project:
    - calendar year 2007 or 2009.

The two research questions are addressed in the following sections.

3.1 Selecting the baseline weather year

This section discusses the methodology, results and conclusion used to address the first research question.

1. *Which is the most suitable year for the project's baseline weather year?*

The literature review supporting this research question can be found in Chapter 2.

3.1.1 Methodology

The electricity demand projections available are for the calendar years 2007 to 2011, which restricts the baseline weather to these years. A financial year rather than calendar year scopes the baseline weather because carbon pricing and renewable energy certificate legislation changes occur at the beginning of a financial year and using a financial year for the baseline weather year makes analysis of these legislative changes easier. So, this leaves four financial years to select amongst.

A focus of the project is electricity infrastructure vulnerability to climate change. So, the financial year with the highest mean temperature and variance is selected to test vulnerability. The mean and variance temperature is calculated using half hourly temperature data from the Australian (BoM 2012a) Weather Stations. Additionally, the project is focused on the NEM's regional nodal structure rather than state based structure, which provides both higher resolution analysis and more realistic modelling. The five weather stations closest to each of the 50 regional demand nodes in the NEM are selected for use in the temperature calculations to provide a representative temperature for the NEM. Appendix B provides network diagrams of these 50 demand nodes plus three supply only nodes at Bayswater, Murray and Hazelwood in NSW and VIC. 54 of the weather stations are selected twice as some nodes on the NEM are close. This double selection of a weather station acts to weight the calculation of the mean and variance temperature in favour of the areas of the NEM with higher nodal density.

3.1.2 Results

Table 3-1 shows the annual temperature mean and variance in the NEM for the financial years 2007-8 to 2010-11. The financial year 2009-10 has both the highest mean temperature and variance, which makes the financial year 2009-10 the best weather baseline year for this project.

Table 3-1 Annual temperature mean and variance in the NEM for financial year 2007-8 to 2010-11

	2007-8	2008-9	2009-10	2010-11
Mean (°C)	15.162	14.963	15.69	14.752
Variance	34.662	36.932	38.772	32.268

(Source: BoM 2012a)

However, the summer temperatures from a global warming perspective are more important. Table 3-2 shows the summer temperature mean and variance in the NEM for the financial years 2007-8 to 2010-11. The financial year 2009-10 has the highest summer mean temperature but the financial year 2008-9 has the highest variance. However, the financial year 2009-10 is still the option that will test the vulnerability of the NEM the most when the relative large size of the difference between the two means is compared to the much smaller difference between the two standard deviations.

Table 3-2 Summer temperature mean and variance in the NEM for financial year 2007-8 to 2010-11

	2007-8	2008-9	2009-10	2010-11
Mean (°C)	19.649	19.791	20.555	19.694
Variance	21.769	28.127	25.686	20.817

(Source: BoM 2012a)

3.1.3 Conclusion

The financial year 2009-10 is the best option for the weather baseline for this project given the methodology.

3.1.4 Further Research

Weighting the mean and variance calculations by the relative size of the annual electricity demand at each node would better reflect the relative importance of the nodes in the NEM.

3.2 Selecting the global climate model and emissions scenario

This section discusses the second research question.

2. *Which global climate model and emissions scenario combination is most suitable for the project?*

The literature review and methodology in Chapter 2 and Appendix A discuss the choice of the carbon emission scenario SRES A1FI and the three GCMs:

- Most likely case – MRI-CGCM2.3.2
- Worst case (hottest) – CSIRO-Mk3.5
- Best case (coolest) – MIROC3.2

For the five environment variables:

- temperature;
- solar radiation;
- relative humidity;
- wind speed;
- rainfall.

This section reviews and refines the choice made in Chapter 2 and Appendix A.

3.2.1 Methodology

The scope for this project is till 2030, so the GCM projections for the environment variables in 2030 are compared. These GCM projections are downloaded from CSIRO (2011) and represent the change in environment variable from 1990. However, this project uses a 2009 weather base year, so the change in environment variable is rebased from 1990 to 2009 before projections are made. The range that is the difference between the largest and smallest projected change in environment variable amongst the three GCMs for the years 2030 and 2035, is calculated to highlight the divergences between the three GCMs. The emissions scenario is A1FI for the entire project as this scenario most closely resembles current conditions and is the most testing scenario for the NEM. The forth report directly addresses water issues in the NEM, so this section addresses environment variables other than rainfall.

3.2.2 Results

Table 3-3 presents the change in average annual mean surface temperature. Table 3-4, Table 3-5, and Table 3-6 present data in the same format as Table 3-1 for the three other environment variables, wind speed (m/s), relative humidity (%) and solar intensity (%), respectively.

Table 3-3 shows the projected change in mean surface temperature from 1990 to 2030 and 2035 for the three GCMs, worst (hottest), most likely and best (coolest) cases for the emissions scenario A1FI for the states and major cities within the NEM region. The range columns show the difference between the largest and smallest projected change in temperature amongst the three GCMs for the years 2030 and 2035.

Table 3-3 shows an apparent aberration amongst the GCMs. The projected increases in temperature from 1990 to 2030 in TAS are 0.38°C, 0.43°C and 0.57°C for the worst hottest, most likely and best coolest GCMs, respectively. The apparent aberration is that the best coolest GCM projection is 0.57°C and worst hottest GCM projection is 0.38°C. There are similar aberrations in the GCMs for QLD. The reason for the aberration is that these are "global" climate model projections being used on a localised scale, so to expect every part of the NEM to rise in temperature in unison between the models is unrealistic. Appendix A shows the selection process for the GCMs to provide consistent representation for the whole of the NEM. This consistency process requires sacrificing the first choice GCM for QLD and TAS. If state level studies for TAS and QLD were conducted, then different GCMs would be selected.

Table 3-3 Projected change in average annual mean surface temperature from 1990 to 2030 and 2035 for three GCMs

	Temperature °C							
	Increase from 1990 to 2030				**Increase from 1990 to 2035**			
States	**Worst Hottest**	**Most Likely**	**Best Coolest**	**Range**	**Worst Hottest**	**Most Likely**	**Best Coolest**	**Range**
QLD	0.88	0.79	0.78	0.10	1.09	0.98	0.96	0.13
SA	0.79	0.64	0.66	0.15	0.98	0.80	0.81	0.18
NSW	0.92	0.71	0.70	0.22	1.14	0.88	0.86	0.28
VIC	0.64	0.56	0.58	0.08	0.79	0.70	0.72	0.09
ACT	0.83	0.64	0.67	0.19	1.02	0.79	0.83	0.23
TAS	0.38	0.43	0.57	0.19	0.47	0.54	0.70	0.23
Cities								
Adelaide	0.50	0.53	0.59	0.09	0.62	0.66	0.73	0.11
Brisbane	0.69	0.66	0.74	0.08	0.86	0.82	0.91	0.09
Canberra	0.83	0.64	0.68	0.19	1.02	0.79	0.84	0.23
Melbourne	0.61	0.56	0.56	0.05	0.76	0.69	0.68	0.08
Sydney	0.80	0.68	0.75	0.12	0.99	0.84	0.93	0.15
Broken Hill	0.85	0.67	0.67	0.18	1.05	0.83	0.82	0.23
Bunbury	0.57	0.54	0.60	0.06	0.70	0.66	0.74	0.08
Cairns	0.46	0.60	0.83	0.37	0.57	0.75	1.02	0.45
Coober Pedy	0.85	0.66	0.66	0.19	1.06	0.82	0.81	0.25
Gladstone	0.65	0.68	0.78	0.13	0.80	0.84	0.95	0.15
Hobart	0.40	0.41	0.59	0.19	0.50	0.51	0.73	0.23
Mackay	0.56	0.69	0.81	0.25	0.69	0.85	1.00	0.31
Mildura	0.75	0.61	0.63	0.14	0.93	0.76	0.77	0.17
Mt Isa	0.96	0.86	0.79	0.17	1.18	1.06	0.97	0.21
Newcastle	0.79	0.70	0.75	0.09	0.98	0.86	0.92	0.12
Townsville	0.55	0.68	0.83	0.28	0.69	0.84	1.02	0.33

(Source: CSIRO 2011)

Table 3-4 Projected change in average annual relative humidity from 1990 to 2030 and 2035 for three GCMs

	Humidity (%)							
	Increase from 1990 to 2030				Increase from 1990 to 2035			
States	Worst Hottest	Most Likely	Best Coolest	Range	Worst Hottest	Most Likely	Best Coolest	Range
QLD	-1.9	-0.7	0.8	2.7	-2.3	-0.8	1.0	3.3
SA	-1.8	-0.6	0.3	2.1	-2.2	-0.8	0.3	2.5
NSW	-2.0	-0.7	0.7	2.7	-2.5	-0.9	0.9	3.4
VIC	-1.5	-0.6	0.1	1.6	-1.9	-0.7	0.1	2.0
ACT	-1.5	-0.6	0.4	1.9	-1.8	-0.8	0.5	2.3
TAS	-0.8	-0.4	0.0	0.8	-1.0	-0.4	0.0	1.0
Cities								
Adelaide	-0.8	-0.5	-0.1	0.7	-1.0	-0.6	-0.1	0.9
Brisbane	-1.0	-0.4	1.0	2.0	-1.3	-0.5	1.2	2.5
Canberra	-1.5	-0.6	0.4	1.9	-1.8	-0.8	0.5	2.3
Melbourne	-1.7	-0.7	0.0	1.7	-2.1	-0.8	0.0	2.1
Sydney	-1.5	-0.6	0.5	2.0	-1.9	-0.7	0.6	2.5
Broken Hill	-1.6	-0.6	0.5	2.1	-1.9	-0.8	0.6	2.5
Bunbury	-0.3	-0.4	-0.1	0.3	-0.4	-0.6	-0.2	0.4
Cairns	-0.4	-0.4	0.0	0.4	-0.5	-0.4	0.0	0.5
Coober Pedy	-2.2	-0.6	0.4	2.6	-2.7	-0.7	0.5	3.2
Gladstone	-0.8	-0.4	0.5	1.3	-1.0	-0.5	0.6	1.6
Hobart	-0.7	-0.3	0.0	0.7	-0.8	-0.3	0.0	0.8
Mackay	-0.5	-0.5	0.5	1.0	-0.6	-0.6	0.6	1.2
Mildura	-1.5	-0.6	0.2	1.7	-1.9	-0.7	0.3	2.2
Mt Isa	-2.1	-0.6	1.0	3.1	-2.6	-0.8	1.2	3.8
Newcastle	-1.8	-0.6	0.7	2.5	-2.3	-0.7	0.9	3.2
Townsville	-0.7	-0.5	0.3	1.0	-0.8	-0.6	0.4	1.2

(Source: CSIRO 2011)

Table 3-5 Projected change in annual average wind speed from 1990 to 2030 and 2035 for three GCMs

	Speed (m/s)							
	Increase from 1990 to 2030				Increase from 1990 to 2035			
States	Worst Hottest	Most Likely	Best Coolest	Range	Worst Hottest	Most Likely	Best Coolest	Range
QLD	0.02	-0.01	0.04	0.05	0.03	-0.01	0.05	0.06
SA	0.06	0.03	-0.03	0.09	0.07	0.03	-0.04	0.11
NSW	0.01	0.00	-0.12	0.13	0.01	0.00	-0.14	0.15
VIC	0.00	0.01	-0.10	0.11	0.00	0.01	-0.13	0.14
ACT	0.00	-0.01	-0.14	0.14	0.00	-0.02	-0.17	0.17
TAS	-0.02	0.01	0.08	0.10	-0.03	0.02	0.10	0.13
Cities								
Adelaide	0.00	0.01	-0.10	0.11	0.01	0.01	-0.13	0.14
Brisbane	0.06	0.03	-0.01	0.07	0.07	0.04	-0.01	0.08
Canberra	0.00	-0.01	-0.14	0.14	0.00	-0.02	-0.17	0.17
Melbourne	-0.01	0.01	-0.10	0.11	-0.02	0.01	-0.13	0.14
Sydney	-0.01	-0.02	-0.13	0.12	-0.01	-0.03	-0.16	0.15
Broken Hill	0.01	0.02	-0.11	0.13	0.01	0.03	-0.13	0.16
Bunbury	-0.12	0.03	-0.09	0.15	-0.14	0.03	-0.11	0.17

	Speed (m/s)							
	Increase from 1990 to 2030				Increase from 1990 to 2035			
States	**Worst Hottest**	**Most Likely**	**Best Coolest**	**Range**	**Worst Hottest**	**Most Likely**	**Best Coolest**	**Range**
Cairns	0.01	0.02	0.11	0.10	0.01	0.03	0.13	0.12
Coober Pedy	0.08	0.02	0.03	0.06	0.09	0.03	0.04	0.06
Gladstone	0.04	0.06	0.08	0.04	0.05	0.07	0.10	0.05
Hobart	0.01	0.03	0.10	0.09	0.01	0.04	0.13	0.12
Mackay	0.04	0.03	0.06	0.03	0.04	0.04	0.08	0.04
Mildura	0.03	0.02	-0.11	0.14	0.04	0.02	-0.13	0.17
Mt Isa	-0.03	-0.07	0.03	0.10	-0.04	-0.09	0.03	0.12
Newcastle	-0.01	-0.02	-0.14	0.13	-0.02	-0.03	-0.17	0.15
Townsville	0.01	0.03	0.07	0.06	0.02	0.04	0.09	0.07

(Source: CSIRO 2011)

Table 3-6 Projected percentage change in average annual solar intensity from 1990 to 2030 and 2035 for three GCMs

	Solar intensity							
	Increase from 1990 to 2030				Increase from 1990 to 2035			
States	**Worst Hottest**	**Most Likely**	**Best Coolest**	**Range**	**Worst Hottest**	**Most Likely**	**Best Coolest**	**Range**
QLD	0.7	0.0	-0.8	0.9	0.0	-0.9	0.7	0.0
SA	0.8	-0.1	-0.1	1.0	-0.1	-0.1	0.8	-0.1
NSW	0.9	0.0	-0.3	1.1	0.0	-0.3	0.9	0.0
VIC	1.1	0.1	2.1	1.4	0.1	2.5	1.1	0.1
ACT	1.1	0.1	1.2	1.4	0.2	1.4	1.1	0.1
TAS	0.9	0.4	1.2	1.1	0.5	1.4	0.9	0.4
Cities								
Adelaide	1.0	0.1	0.7	1.2	0.2	0.9	1.0	0.1
Brisbane	1.0	0.1	-1.0	1.2	0.1	-1.2	1.0	0.1
Canberra	1.1	0.1	1.0	1.3	0.2	1.2	1.1	0.1
Melbourne	1.2	0.1	3.0	1.5	0.1	3.7	1.2	0.1
Sydney	0.8	0.2	-0.2	1.0	0.2	-0.2	0.8	0.2
Broken Hill	0.7	-0.1	-0.3	0.8	-0.1	-0.3	0.7	-0.1
Bunbury	0.4	0.1	1.6	0.4	0.1	1.9	0.4	0.1
Cairns	0.7	0.1	-0.1	0.8	0.2	-0.2	0.7	0.1
Coober Pedy	0.8	-0.1	-0.3	1.0	-0.1	-0.4	0.8	-0.1
Gladstone	0.7	0.1	-0.6	0.9	0.1	-0.7	0.7	0.1
Hobart	0.6	0.4	0.5	0.8	0.5	0.6	0.6	0.4
Mackay	0.5	0.1	-0.7	0.7	0.1	-0.8	0.5	0.1
Mildura	0.8	0.1	0.4	1.0	0.1	0.5	0.8	0.1
Mt Isa	0.7	-0.1	-0.8	0.9	-0.1	-1.0	0.7	-0.1
Newcastle	0.8	0.2	-0.5	1.0	0.2	-0.7	0.8	0.2
Townsville	0.6	0.1	-0.5	0.7	0.1	-0.6	0.6	0.1

(Source: CSIRO 2011)

3.2.3 Discussion

This project uses annual state level climate change data and a single GCM. This is an expedient decision given the time available and the project scope to 2030. So, the hottest or worst case GCM is used to test the vulnerability of the NEM. Furthermore, the divergence at the state level for 2030 between the GCMs represented by the range column in Table 3-3 to Table 3-6 is small, which justifies the use a single GCM.

However, if the scope of the project is extended to 2035, the GCMs start to diverge, which makes the comparison of the three GCMs more interesting. In addition, if higher resolution GCM data is used, the divergence becomes more marked. This can be seen by comparing the light grey sections within each table, which contrast the change in environment variable between the state level in 2030 and the city level in 2035.

Further research in Section 3.5 discusses using seasonal climate change data and the availability of even higher resolution geographic data.

3.2.4 Conclusion

The GCM for the worst case (hottest) CSIRO-Mk3.5 using annual change data at the state level is satisfactory for the scope of this project. But consideration should be given to extending the scope of the project from 2030 to 2035, from one GCM to three GCMs, from annual to seasonal change data and from state to high resolution geographic data.

3.2.5 Further research

3.2.5.1 Extending the project from 2030 to 2035, from one GCM to three GCMs, from annual change data to seasonal and from state to high geographic resolution data

Section 3.4 discusses extending the project from 2030 to 2035 and from one GCM to three GCMs. This section discusses extending the project from annual to seasonal climate change data and from state level to high resolution geographic data. The GCM data from CSIRO (2011) was applied to a high resolution baseline data set consisting of 11,294 points across Australia. Table 3-1 illustrates the necessity of using high resolution seasonal data. Table 3-1 shows the seasonal change in wind speed (m/s) from 1990 to 2035 for the GCM CSIRO-Mk3.5 and emission scenario A1FI. The annual average by state climate change range is 0.10 m/s. This masks considerable interregional and seasonal differences. For instance, Adelaide shows a seasonal range of 1.52 m/s and the high resolution data for the month of February shows an interregional range of 2.43 m/s.

Using the high resolution seasonal data may provide more divergence between the three GCMs and will enable much more realistic incrementing of the environment variable data from the 250 Australian weather station used in the demand projection in Section 6.

3.2.5.2 Wind generation and reduced interregional wind speed correlation

This predicted increase in interregional difference in wind speed induce by climate change has implications for wind generation and transmission capacity. The predicted reduced correlation in wind speed between regions improves the ability to export wind generated electricity between regions and reduces wind generation intermittency concerns. However, to take advantage of this situation may require more investment in both interstate and intrastate transmission infrastructure. Only a seasonal high resolution study could address this research issue.

3.2.5.3 Solar PV and reduced interregional solar intensity correlation

Section 3.5.2 focuses on wind generation but a similar study on solar PV is warranted.

3.2.5.4 Energy portfolios addressing solar PV and wind generation intermittency

CSIRO (2012b) discusses how intermittency is one of the biggest barriers to the uptake of solar energy. Intermittency is also a factor curtailing the fuller deployment of wind generation. Solar PV and wind generation intermittence is uncorrelated, which provides the opportunity to use energy portfolios to address intermittency. Only a seasonal high resolution study could address this research issue by building on the research suggested in Sections 3.5.2 and 2.5.4.

Section 4 discusses how non-scheduled solar PV and wind generation affect electricity demand.

3.2.5.5 Increases in severe weather events

Chapter 2 discusses the increase in serve weather event. This situation has major implications for risk management and the insurance costs. Further research into the increases in serve weather events and the associated insurance costs is warranted.

Table 3-1 Seasonal change in wind speed (m/s) from 1990 to 2035 for the GCM CSIRO-Mk3.5 and emission scenario A1FI

States	Annual	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Range
QLD	0.03	0.12	0.03	-0.15	-0.07	0.01	0.01	-0.03	0.02	0.10	0.12	0.12	0.05	**0.27**
SA	0.07	0.17	0.12	0.23	0.19	0.19	-0.18	-0.21	-0.10	0.03	0.29	0.04	0.11	**0.50**
NSW	0.01	0.06	0.04	0.07	0.11	0.07	-0.20	-0.07	-0.20	-0.25	0.19	0.07	0.23	**0.48**
VIC	0.00	0.23	0.27	0.49	-0.12	-0.24	-0.40	-0.01	-0.18	-0.55	-0.10	0.13	0.45	**1.04**
ACT	0.00	-0.03	0.24	0.21	-0.09	-0.09	-0.34	0.10	-0.12	-0.40	-0.13	0.24	0.34	**0.74**
TAS	-0.03	0.16	-0.21	-0.06	-0.25	-0.02	-0.20	0.13	0.12	-0.21	-0.05	-0.11	0.34	**0.59**
State Range	**0.10**	**0.26**	**0.48**	**0.64**	**0.44**	**0.43**	**0.41**	**0.34**	**0.32**	**0.65**	**0.42**	**0.35**	**0.40**	
Cities														
Adelaide	0.01	0.21	0.19	0.32	0.79	-0.32	-0.46	-0.08	-0.26	-0.73	0.05	0.14	0.22	**1.52**
Brisbane	0.07	0.10	0.03	-0.03	0.03	-0.14	-0.03	-0.21	0.08	0.13	0.47	0.27	0.14	**0.68**
Canberra	0.00	-0.03	0.22	0.23	0.01	-0.10	-0.34	0.10	-0.12	-0.40	-0.12	0.24	0.32	**0.72**
Melbourne	-0.02	0.28	0.31	0.75	-0.61	-0.25	-0.38	-0.03	-0.19	-0.56	-0.16	0.09	0.55	**1.36**
Sydney	-0.01	0.00	0.13	0.25	0.25	-0.28	-0.39	0.05	-0.26	-0.46	0.10	0.21	0.33	**0.79**
Broken Hill	0.01	0.20	-0.01	0.24	0.23	0.19	-0.43	-0.12	-0.28	-0.44	0.27	0.01	0.28	**0.72**
Bunbury	-0.14	0.19	-0.02	-0.18	0.18	-0.10	-0.61	-0.29	-0.38	-0.45	-0.14	0.00	0.07	**0.80**
Cairns	0.01	0.01	0.16	-0.10	0.11	-0.01	-0.13	-0.12	-0.01	0.14	-0.06	0.14	0.00	**0.29**
Coober Pedy	0.09	0.28	0.26	0.30	0.08	0.09	-0.19	-0.41	-0.23	0.31	0.49	-0.01	0.16	**0.90**
Gladstone	0.05	0.05	-0.08	0.06	0.10	0.00	-0.18	-0.10	0.06	0.19	0.26	0.21	0.08	**0.44**
Hobart	0.01	0.12	-0.24	-0.18	-0.05	0.09	-0.10	0.19	0.21	-0.08	-0.01	-0.12	0.27	**0.51**
Mackay	0.04	0.05	0.13	0.04	0.07	-0.01	-0.17	-0.11	0.00	0.15	0.12	0.21	0.06	**0.38**
Mildura	0.04	0.30	0.21	0.42	0.61	-0.06	-0.51	-0.08	-0.28	-0.62	0.12	0.05	0.35	**1.23**
Mt Isa	-0.04	0.18	-0.05	-0.31	-0.08	0.07	0.05	0.00	0.06	0.05	-0.22	-0.04	-0.15	**0.49**
Newcastle	-0.02	-0.04	0.08	0.24	0.13	-0.40	-0.35	-0.02	-0.29	-0.37	0.26	0.23	0.33	**0.73**
Townsville	0.02	0.05	0.21	-0.05	0.04	-0.02	-0.12	-0.09	-0.03	0.14	-0.04	0.18	-0.04	**0.33**
City Range	**0.23**	**0.34**	**0.55**	**1.06**	**1.40**	**0.59**	**0.66**	**0.60**	**0.59**	**1.04**	**0.71**	**0.39**	**0.70**	
High Res. Range	**0.7**	**1.77**	**2.43**	**2.25**	**2.18**	**1.95**	**1.81**	**1.15**	**1.34**	**2.14**	**1.54**	**1.37**	**1.65**	

(Source: CSIRO 2011)

3.3 Discussion

Sections 3.1 and 3.2 present and discuss the results to the smaller research questions presented in the introduction to this chapter. These smaller questions are developed from the project's overarching research questions or four sources of maladaptation to climate change listed below:

1. institutional fragmentation, both economically and politically;
2. distorted transmission and distribution investment deferment mechanisms;
3. lacking mechanisms to develop a diversified energy portfolio; and
4. failure to model and to treat the NEM as a national node based entity rather than state based.

This section relates the finding from Sections 3.1 to 3.3 back to the overarching research question for the project. The discussion in this chapter will focus on network service providers and leave discussion of generation and retail to Chapter 7 and 11, respectively. Retail and generation are amenable to a competitive environment but network service provision is a natural monopoly.

Section 3.2 identified a benefit from climate change that is an increase in both regional and seasonal variation in wind speed from 1990 to 2035, see Table 3-7. This increased variation provides the opportunity to export wind generated electricity between regions. Taking advantage of this opportunity necessitates modelling and treating the NEM as a national node based entity rather than taking a narrow state based focus. A single company owning all the distribution and transmission lines would be in a better position to take advantage of such an opportunity by reducing coordination costs and providing a national perspective. Such a move would help address research question 1, 3 and 4 by reducing economic fragmentation, helping further establish wind generation as part of an energy portfolio and treating the NEM as a national node based entity.

Chapter 2 discusses the expected increases in severe weather events. This project recommends the modelling of severe weather events and risk management implications in further research. These severe weather events can be particularly devastating for network infrastructure. The normal course of action is to insure against such events. This insurance will become more expensive as the events become more frequent, as insurance companies are only intermediaries that spread the risk over those with policies. An alternative approach to insurance is to manage the risk internally. This is not really an option for the 13 NSPs in the NEM but a monopoly NSP owning the entire network infrastructure of the NEM has a large geographic spread. This geographic spread and much larger capital base makes internal risk management an option.

3.4 Conclusion

This chapter has linked the findings from selecting suitable GCM and baseline weather year to the four factors contributing to the NEM's maladaptation to climate change:

1. institutional fragmentation, both economically and politically;
2. distorted transmission and distribution investment deferment mechanisms;
3. lacking mechanisms to develop a diversified energy portfolio; and
4. failure to model and to treat the NEM as a national node based entity rather than state based.

This chapter has also identified the financial year 2009-10 as the best baseline weather year for the project. Additionally, this chapter has identified the most suitable GCM for this project as CSIRO-Mk3.5, which is the worst case hottest scenario for the NEM.

4. THE IMPACT OF CLIMATE CHANGE ON ELECTRICITY DEMAND: REVIEW

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There has been an increase in demand for electricity for over two decades. However there are many countervailing trends in the demand for electricity. For instance there is uneven population growth across Australia, which will increase demand unevenly. The growth in the uptake of air conditioners is nearing a plateau, which will reduce the rate of increase in electricity demand. The price for electricity has increased rapidly over the last 10 years, which may see people become sensitive to price, so a price elasticity of demand starts to slow the rate of increase in demand. There are education campaigns to make people aware of their electricity use, which will reduce the rate of increase. Finally, there is climate change affecting both temperature and humidity, which could provide a countervailing effect on demand for electricity where an increase in temperature increases the use of air conditioners and a decrease in humidity decreases demand for air conditioners. The aforementioned countervailing trends make temporal and geographic modelling of demand essential to make predictions.

This chapter discusses the aforementioned trends in demand to expose any maladaptive policy and to inform the development of a model of demand to produce demand profiles.

4.1 Demand profiles

For this project, the demand profile is the electricity demanded in MWh for each hour of the day for 20 years from 2010 to 2030. There is a demand profile for each of the nodes on the NEM grid. Appendix B shows the 11 nodes in Queensland's transmission line topology. These nodes serve three functions:

- demand - the node represents an area or region of demand;
- supply - the node represents the connection point for generators; and
- transmission - two nodes represent the connection points.

Geographically the demand is an area, the generators are points and the transmission lines are lines. These three topologies have a bearing on the use of the climate change projections. In addition, for demand, there is a requirement to relate population projections to these nodes. The population and climate change projections are used to create a demand profile for each of the 53 nodes on the NEM. The 53 nodes of the NEM are shown in Appendix B for QLD, NSW, VIC, SA and TAS. Note that the nodes for ACT are incorporated within the node structure of NSW. These figures represent the topology of the network rather than geographic distance.

Notably, the nodes Bayswater, Murray and Hazelwood are supply only nodes without any demand. Additionally, there are three pseudo demand nodes at Moreton North, Wollongong and Tumut, which are required for modelling the demand from the pumped hydro storage at Wivenhoe, Shoalhaven and Tumut respectively. Furthermore, in Appendix B for Queensland the node called 'South West' is to be re-designated by Powerlink (2011 App. C) as two nodes being Bulli and South West.

However this project will continue to use the topology in Appendix B that is with the single node 'South West' without Bulli, for two reasons:

- there lacks historical data on the two nodes to calibrate the models; and
- the project has a tight deadline.

4.2 Short-run and long-run drivers for electricity demand

Yates and Mendis (2009, p. 111) consider short-run drivers for demand due to weather and long-run driver due to climate change. For instance, in the short-run people can turn on fans or air conditions to meet changes in weather conditions and in the long-run people can buy air conditioners or install insulation to meet climate change.

Yates and Mendis (2009, p. 111) consider the following short-run electricity demand drivers:

- weather – air temperature, wind speed, air humidity and radiation;
- indoor environmental factors – indoor air temperature, wind speed and humidity;
- time of the day;
- day of the week;
- holidays;
- seasons;
- durations of extreme heat days;
- urban heat island effects;
- utilisation of appliances;
- person's financial position; and
- personal factors – clothing, physical activity and acclimatisation.

Yates and Mendis (2009, p. 112) consider the following long-run drivers:

- climate change;
- population growth composition and geographic distribution;
- real price of electricity;
- the price of electricity relative to the price of gas;
- economic growth;
- real income and employment status;
- interest rates;
- renewal of building stock;
- households and floor space per capita;
- previous years consumption; and
- commercial and industrial electricity use.

There is extensive literature in short-run electricity demand forecasting. However, Taylor and Buizza (2003) state that there is no consensus as to the best approach to electricity demand forecasting citing three different approaches. Harvey and Koopman (1993) forecast hourly demand using time-varying splines, Ramanathan et al. (1997) use multiple regression models and Hippert et al. (2001) use artificial neural networks for short-run forecasting. For this project, regression is chosen because it is the most commonly understood method.

There is a much less extensive literature on long-run electricity demand projections. In addition, Yates and Mendis (2009, p. 113) consider that there are the following difficulties in producing long-run projections:

- limitations in climate change projections;
- limitations in demand modelling;
- limitations in data; and
- lack of industry sector studies.

However this project must extend the literature on short-run electricity demand forecasting to form long-run electricity demand projections. The method essentially involves using the existing literature to form a short-run forecasting model of electricity demand, then using the short-run forecasting model on simulated weather profiles of the years from 2010 to 2030. The simulated weather profiles are generated using the project's baseline weather year incremented by climate change projections. These resulting demand projections are factored for long-run derivers of electricity demand, such as population growth.

4.3 Weather and other short-run drivers for electricity demand

Equation (4-1) shows the short-run factors or weather variables driving demand that are readily modelled from the previous section and based on Ramanathan et al. (1997, p. 163).

$$d_{(s,\, dow\, ,t,\, h,\, n)} = f(T,p,w,r)_{(s,\, dow\, ,t,\, h,\, n)} + AR$$

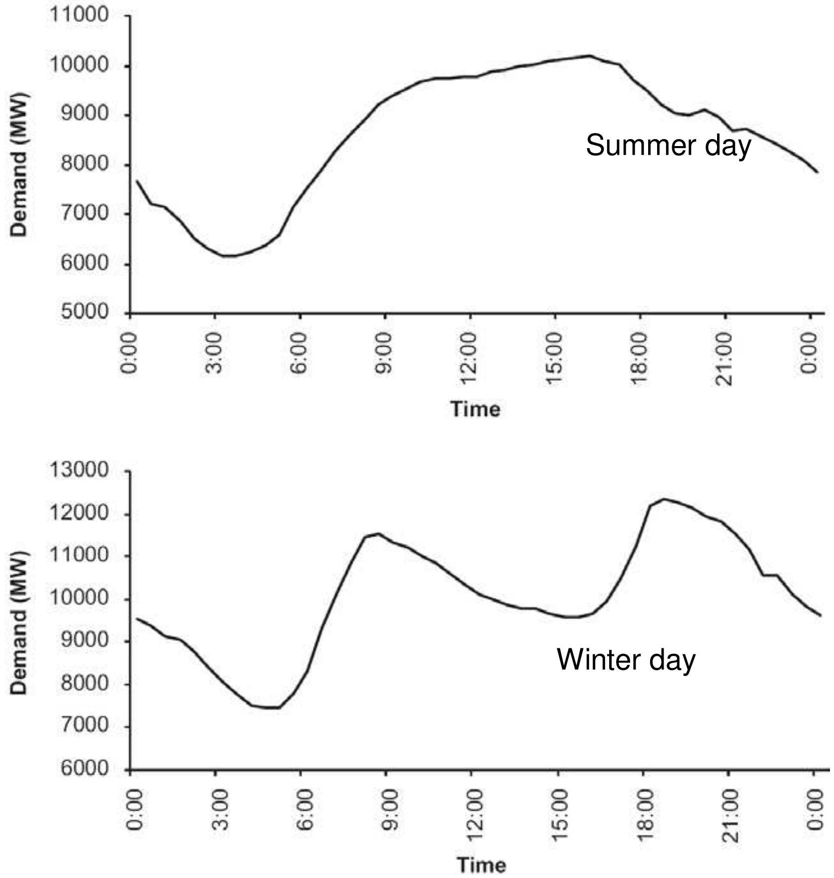
Where

d = demand
s = season
dow = day of week
t = hour
h = holiday
n = node
f = function
T = temperature
p = per cent humidity
w = wind speed
r = radiation
AR = autoregressive term

Equation (4-1)

The subscripts in Equation (4-1) mean that there is a separate equation for each season, either summer or winter, for each day of the week, for each hour of the day, for whether the day is a holiday or not and for each node. Figure 4-1 shows the typical demand profiles for summer and winter days. In summer, people start to use the air conditioners about mid-morning and continue using air conditioners until late afternoon. In winter, people use the heating early in the morning and later evening but tend to switch off the heating during the middle of the day. This difference in profile illustrates the importance of capturing the typical summer and winter day in Equation (4-1).

Figure 4-1 Examples of the NSW intraday demand for a typical summer and winter day



(Source: Thatcher 2007, p. 1649)

Equation (4-1) ignores a *person's financial position* and *personal factors* as the equation models an aggregation of all the consumers on a node. Equation (4-1) captures the *utilisation of appliances*, in particular air conditioners, by using the variables for time of day and temperature. Equation (4-1) partially captures the *urban heat island effects* using the node variable. The *durations of extreme heat days* affect the use of air conditioners as buildings retain heat from the previous day. The auto regressive term in Equation (4-1) captures this residual heat effect. The auto regressive term simply means that today's demand for electricity is related to yesterday's demand for electricity, which is related to the demand for electricity of the day before yesterday, and so on but the relationship dissipates over time.

There is a possibility that the environment variables are highly correlated or synchronised, so a subset of the variables, that are the most uncorrelated, are selected to form the regression to model the demand for electricity. The process is known as *principle component analysis* of historical demand. For instance, the effect of the following four variables on demand for electricity may be adequately modelled with just three of the variables: population, number of air conditioners owned, number of households and climate change.

Table 4-1 cites results from Preston and Jones (2006) who forecast the increase in peak demand under given temperature increases for Adelaide, Brisbane, Melbourne and Sydney. The response to an increase in temperature varies greatly between the metropolitan centres, which stresses the importance of modelling demand for each node.

Table 4-1 Effect of temperature change on peak demand for electricity in four capital cities

ΔT (°C)	Projected impact on peak electricity demand
<1	Melbourne and Sydney decreases up to 1% Adelaide and Brisbane increases 2–5%
1-2	Melbourne and Sydney decreases 1% Adelaide and Brisbane increases 4–10%
2-3	Adelaide, Brisbane and Melbourne increases 3–15% Sydney decreases 1%
3-4	Adelaide, Brisbane and Melbourne increases 5–20% Sydney decreases 1%
4-5	Adelaide, Brisbane and Melbourne increases 9–25% Sydney decreases 0.5%
>5	Sydney decreases 0% Adelaide, Brisbane and Melbourne increases 10–25%

(Source: Preston & Jones 2006, p. 29)

Table 4-2 show the increase in peak demand for a one degree increase in temperature in the states NSW, VIC, QLD and SA.

Table 4-2 Projected increase in peak demand for a one degree increase in temperature

Region	Change in peak regional electricity demand
NSW	–2.1% ±1.0%
VIC	–0.1% ±0.7%
QLD	+1.1% ±1.4%
SA	+4.6% ±2.7%

(Source: Thatcher 2007, p. 1655)

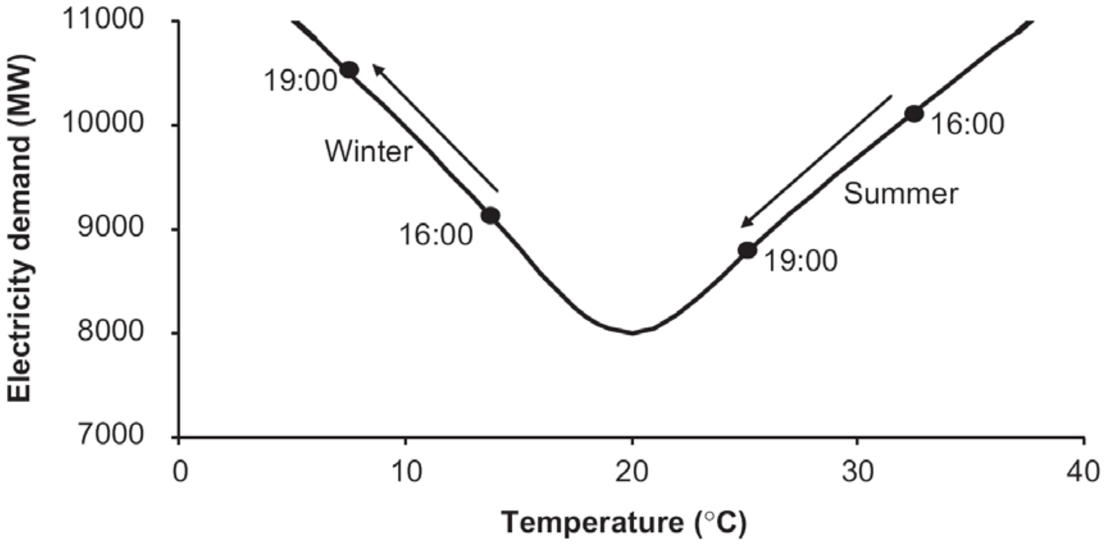
When comparing Table 4-1 and Table 4-2 it indicates a discrepancy between the change in peak demand between the capital city and the state. The *urban heat island effect* can partially explain why demand in a capital city would differ to the state. This discrepancy adds weight to the need to model demand for each node rather than aggregate by state. Unfortunately, the demand profiles of the years 2006 to 2011 from AEMO (2011a) are aggregated by state. However, the demand profiles for each node are available via company websites and annual reports.

Furthermore, these large increases in peak demand have traditionally been met by increased investment in generation, transmission and distribution even though the peaks are for relative short periods. The consequence is a considerable increase to electricity bills to meet peak demand, which lasts for a relatively short duration. Chapters 6 and 10 discuss methods to defer investment in generation, transmission and distribution.

Howden and Crimp (2001) and Thatcher (2007) use Heating Degree Days (HDD) and Cooling Degree Days (CDD) to model the effect of temperature on peak demand. This degree day technique provides a better modelling technique than the season variable in Equation (4-1), as the degree day technique accommodates unseasonal days. For instance, with regards to the profile in Figure 4-1 there are very cold summer's days that could have the winter's day demand profile and very hot winter's days that could have the summer's day demand profile.

Figure 4-2 shows a schematic that illustrates the degree day concept where in summer at high temperatures the demand at 16:00 is greater than at 19:00 and in winter at low temperatures the situation is reversed. This technique can be applied to any hot or cold day but a base temperature (T_b) is required to determine whether a day is a HDD or a CCD. In Figure 4-2, the base temperature appears about 20°C.

Figure 4-2 Relationship between electricity demand and temperature at different time



(Source: Thatcher 2007, p. 1650)

Table 4-3 shows that the base temperature varies amongst the capital cities and state and between capital city and home state, which adds further weight to developing demand profiles for each node. As expected, the base temperatures forms some indication of acclimatisation, for instance the base temperature for Brisbane is higher than Melbourne, which indicates that somebody in Melbourne is more likely to switch on an air conditioner at lower temperature than somebody in Brisbane and that somebody in Brisbane is more likely to switch on heating at a higher temperature than somebody in Melbourne.

Table 4-3 Comparing base temperature in degrees Celsius for cities and states

City	T_b	T_b	State
Brisbane	18.6	19.70	QLD
Sydney	17.5	19.16	NSW
Melbourne	16.9	16.94	VIC
Adelaide	16.8	18.08	SA
(Source: Howden & Crimp 2001, p. 656)		*(Source: Thatcher 2007, p. 1653)*	

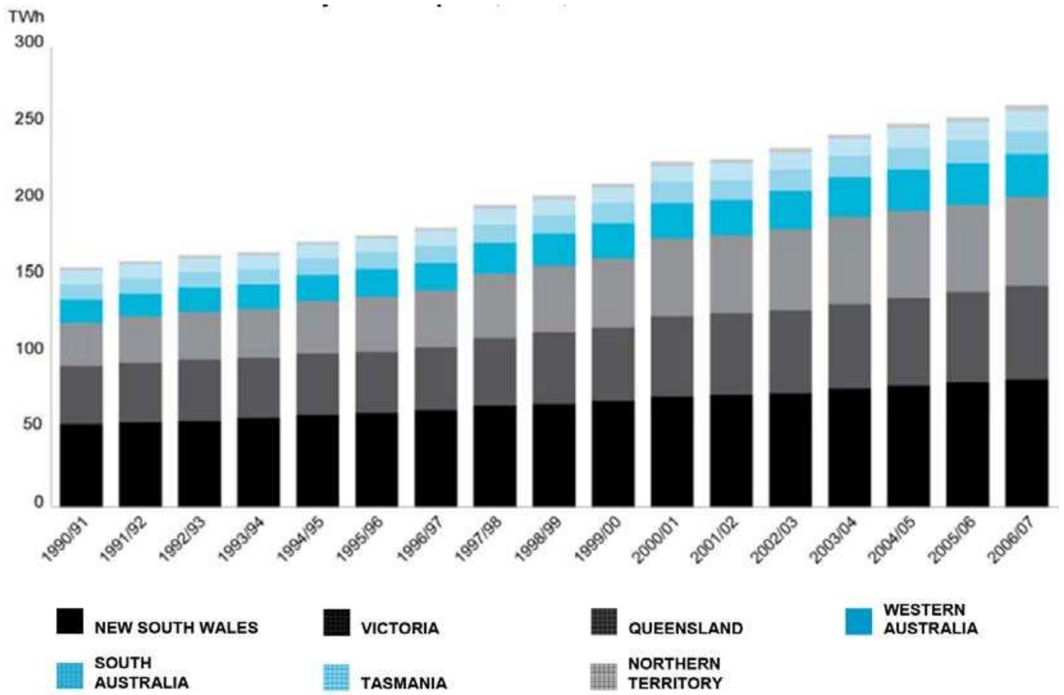
As previously discussed, Equation (4-1) fails to accommodate personal acclimatisation but the degree day technique using base temperatures accommodates personal acclimatisation to a location. So, there are two reasons to adopt the degree day technique over the season variable in Equation (1), being accommodating unseasonal days and acclimatisation to the local climate.

Howden and Crimp (2001) and Thatcher (2007) include a measure for humidity. Howden and Crimp (2001) found that the inclusion of humidity improved the models' predictive performance for Brisbane for both CDD and HDD and for Melbourne for CDD only. However the measure for temperature proved a sufficient variable to model demand for both CDD and HDD for both Sydney and Adelaide.

4.4 Climate and population as long-run drivers for electricity demand

Figure 4-3 shows the demand for electricity increasing from 1990 to 2006 by 67%. The Chairman of the AEMC (Tamblyn 2008) expects this tend to continue, requiring further investment in generation, transmission and distribution, which is discussed in Chapter 6.

Figure 4-3 Electricity consumption, TWh, 1990-91 to 2006-07



(Source: Tamblyn 2008, p. 15)

Some of this increase in demand is due to population growth and climate change. The mechanism for population growth increasing demand for electricity is obvious but the mechanism for climate change increasing demand for electricity is more indirect. For instance, warmer temperatures encourage people to install more air conditioners and use the air conditions more often. Both population growth and climate change are long-run demand drivers and are readily modelled.

However, the following long-run demand drivers are not so easily modelled for the 20 year duration of the project:

- public engagement and the smart grid;
- acclimatisation to climate change;
- air conditioner purchases;
- real price of electricity - price elasticity of demand;
- the price of electricity relative to the price of gas;
- real income and employment status;

- interest rates;
- economic growth;
- renewal of building stock;
- households and floor space per capita;
- previous years' consumption; and
- commercial and industrial electricity.

Chapter 2 discusses the selection of this project's *Special Report on Emission Scenario* (SRES) A1FI and three Global Climate Models (GCMs) used to produce the climate change projections for the *'Worst case'*, *'Most likely case'* and *'Best case'*. These three climate projections are used to produce demand profiles in conjunction with population projections.

This section discusses the three Australian Bureau of Statistics (ABS 2008) population projections used in this project. The ABS (2008, p. 3) states, *"Three main series of projections, Series A, B and C, have been selected from a possible 72 individual combinations of the various assumptions. Series B largely reflects current trends in fertility, life expectancy at birth, net overseas migration and net interstate migration, whereas Series A and Series C are based on high and low assumptions for each of these variables respectively".*

Table 4-4 shows the population projection assumptions and the expected increases in population from 2006 to 2030. The projected population percentage increase provides an indication of the expected increase in demand for electricity from population growth.

Table 4-4 Population projection assumptions and increase from 2006 to 2030

	Total fertility rate	Net overseas migration	Life expectancy at birth		Actual Population	Projected Population	
	Babies per woman	persons	Males year	Females years	30 June 2006	30 June 2030	Increase
Series A	2.0	220 000	93.9	96.1	20,697,880	30,499,959	47%
Series B	1.8	180 000	85.0	88.0	20,697,880	28,484,167	38%
Series C	1.6	140 000	85.0	88.0	20,697,880	26,851,511	30%

(Source: ABS 2008)

However, for Series B, Table 4-5 shows that this population growth and induced growth in demand for electricity is unevenly spread across the NEM region with Queensland expecting significantly more growth and Tasmania the least growth. Additionally, there is marked difference in growth between the capital city and the balance of the state for VIC, NSW, TAS and SA. Consequently, modelling population by node would better reflect the stresses induced on the NEM by this uneven population growth.

Table 4-5 Uneven projected population growth from 2006 to 2030 across the NEM

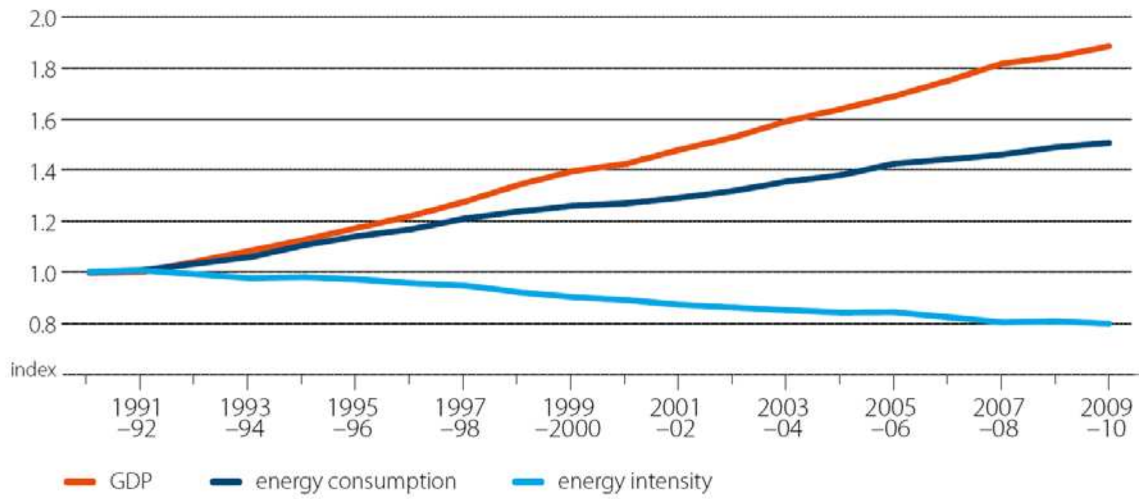
Series B	Qld	NSW	Vic	SA	Tas	ACT	NEM
State	57%	27%	36%	24%	14%	29%	36%
Capital city	57%	32%	41%	25%	22%		38%
Balance of state	57%	20%	20%	21%	8%		32%

(Source: ABS 2008)

4.5 The link between economic growth and growth in demand for electricity

Figure 4-4 shows that growth in energy consumption has remained below the growth in Gross Domestic Product (GDP) and energy-intensity has been declining. Energy-intensity is the ratio of energy used to activity in the Australian economy. Ball et al. (2011, p. 8) discuss how declining energy-intensity is a worldwide phenomenon.

Figure 4-4 Intensity of Australian energy consumption

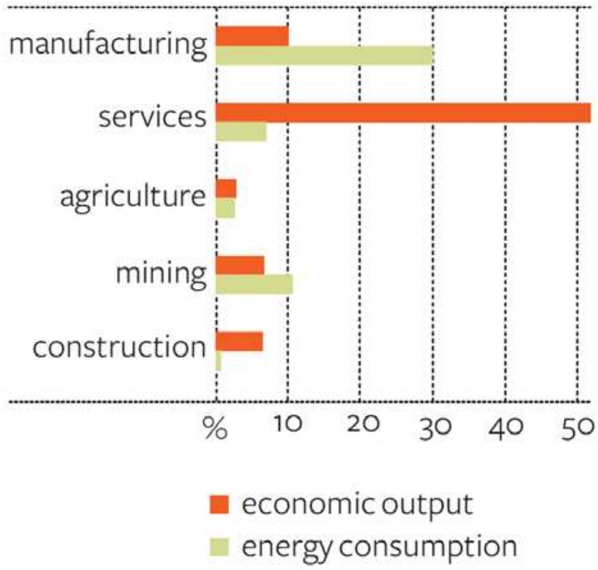


(Source: Schultz & Petchey 2011, p. 5)

Shultz and Petchey (2011, p. 5) consider the decline in energy-intensity due to two factors being the improvement in energy efficiency associated with technological advancement and a shift in industry structure toward less energy-intensive sectors. The improvement in energy efficiency is likely to continue and is further discussed in the following sections. Figure 4-5 compares the percentage share of economic output and of energy use for different industries. Manufacturing is the most energy intense industry and the service industry is one of the least intensive industries. The increase in the size of the service industry and decrease in the size of the manufacturing industry accounts for some of the decline in energy-intensity. The decline in energy-intensity requires modelling to adjust the demand profiles developed from the population and climate projections. The next section discusses why this long run trend is likely to continue.

The long term drivers of increasing population and economic growth do not necessarily have to lead to an increase in demand for electricity. In other countries, particularly in Europe, these long term drivers have been managed by not using or minimising the use of electricity for heating and cooling (the largest growth demands) by using the waste heat from local electricity generation, renewable heat or the injection of renewable gas into the gas grid. These have additional benefits of decentralising energy generation close to demand, increasing the efficiency of the energy system, reducing losses and providing the opportunity for the undergrounding of electricity infrastructure – a classic case of adapting to climate change.

Figure 4-5 Shares of energy consumption and economic output 2005-06



(Source: Sandu, Suwin & Syed 2008, p. 4)

4.6 Smart meters as long run drivers for reducing electricity demand

This section discusses how smart meters providing customers with dynamic pricing can help customers reduce demand for electricity at peak times and increase public engagement in energy conservation.

Smart meters allow retailers to automatically collect high frequency data on customers' electricity usage and customers to monitor their own use of electricity. Smith and Hargroves (2007) discusses the introduction of smart meters, the ensuing public engagement and the substantial reduction in peak demand being achieved. Currently in Australia, transmission and distribution investment is made to meet the peak demand period, which is usually between 3 pm and 6 pm in most Organisation for Economic Co-Operations and Development (OECD) countries. Smith and Hargroves (2007) state that in Victoria the transmission investment is 20 per cent larger to meet peak demand for one per cent of the year. In comparison, Georgia Power and Gulf Power in Florida, USA, have installed smart meters resulting in Georgia Power's large customers reducing electricity demand by 20-30 per cent during peak times and Gulf Power achieving a 41 per cent reduction in load during peak times. Zoi (2005) reports on California's experience of tackling the growing demand for peak summer power using a deployment of smart meters with a voluntary option for real time metering that uses lower tariffs during off peak times and higher tariffs during peak times with a 'critical peak price' reserved for short periods when the electricity system is really stressed. Energy consumption during peak periods was reduced by 12-35 per cent. Most Californians now have lower electricity bills and 90 per cent of participants support the use of dynamic rates throughout the state.

The AEMC (2009, p. v) considers fixed priced tariffs for retail customers a risk to the NEM with the introduction of the RET and the Carbon Pollution Reduction Scheme (CPRS), so the AEMC (2009, p. v) recommends more flexible pricing for retail customers to reflect the movements in wholesale prices. In addition, it recommends a national customer protection scheme be setup prior to introducing flexible pricing. A flexible retail consumer price reduces the risk for the electricity companies and transfers the risk to the retail customer. However, if the retail customers lack in-house-displays for their smart meters, the customers will be unable to readily adapt to changes in price. Introducing flexible pricing before smart meters with in-house-displays could induce a negative response from customers, so hindering consumer engagement in energy conservation. For instance the World Energy Council (WEC 2010) evaluates the residential smart meter policies of Victoria and claim the lack of an in-house-display is a major source of customer dissatisfaction amongst customers with dynamic prices. Another source of dissatisfaction is the lack of provision for the most financially vulnerable. Section 9.5 discusses institutional fragmentation as a cause of the slow smart meter deployment in Australia and as a source of maladaptation to climate change.

4.7 Energy efficiency as a long run driver for reducing electricity demand

Institutional fragmentation is also hindering policies surrounding energy efficiency. Hepworth (2011a) reports how AGL and Origin Energy called for a national scheme rather than state based schemes because compliance across the different states' legislations is costly. However the National Framework for Energy Efficiency (NFEE 2007) instituted by the MCE claims significant progress. But in a submission to the NFEE (2007) consultation paper for stage 2, the National Generators Forum (NGF 2007) comments on the progress since stage 1 of the NFEE *"Progress in improving the efficiency of residential and commercial buildings can best be described as slow and uncoordinated, with a confusion of very mixed requirements at the various state levels. … Activities in areas of trade and professional training and accreditation, finance sector and government have been largely invisible from a public perspective"*. The NGF (2007) states that the proposals for stage 2 are modest and lack coordination and national consistency. So, there is disagreement between the MCE and participants in the NEM over coordination in the NEM. Section 9.6 further discusses coordination problems induced by institutional fragmentation as a cause of maladaptation to climate change.

In another submission to the consultation paper, Origin Energy (2007) calls for the NFEE to focus on non-price barriers to energy efficiency that the price signal from the CPRS is unable to address. Claiming the public good aspect of energy efficiency provides strong justification for government funding even where there are private benefits through cost savings. Origin Energy considers the following items are suitable for direct action to remove non price barriers:

- education/information campaigns;
- low interest or zero interest loans;
- minimum Energy Performance Standards (MEPS);
- phasing out electric hot water systems;
- incandescent light bulb phase out; and
- building standards.

Stevens (2008, p. 28) identifies the need for raising public awareness of electricity demand and shaping public opinion as part of an adaptive strategy but Origin Energy (2007) considers public education/information campaigns are considerably underfunded. The star rating of appliances by Equipment Energy Efficiency (E3 2011) is an example of a campaign that is visible and easy to understand, which is moot with some success and addresses information asymmetry. As discussed, the introduction of smart meters and flexible pricing has engaged customers in other countries. This public engagement by smart meters can provoke a much wider interest in the conservation of electricity to include energy efficiency.

Additionally, Origin Energy (2007) supports interest free loans to undertake energy efficiency projects with high upfront costs, particularly for poorer individuals or smaller businesses that have difficulty accessing finance. Section 9.1 further discusses interest free loans and peoples' expectation of a much shorter payback period on an investment than is economically optimal as justification for government intervention.

Both Origin Energy (2007) and NGF (2007) acknowledge that the MEPS established for refrigerators and freezers, electric water heaters and refrigerative air conditioners are effective and support the expansion of MEPS to include other appliances. MEPS are a successful adaption to climate change.

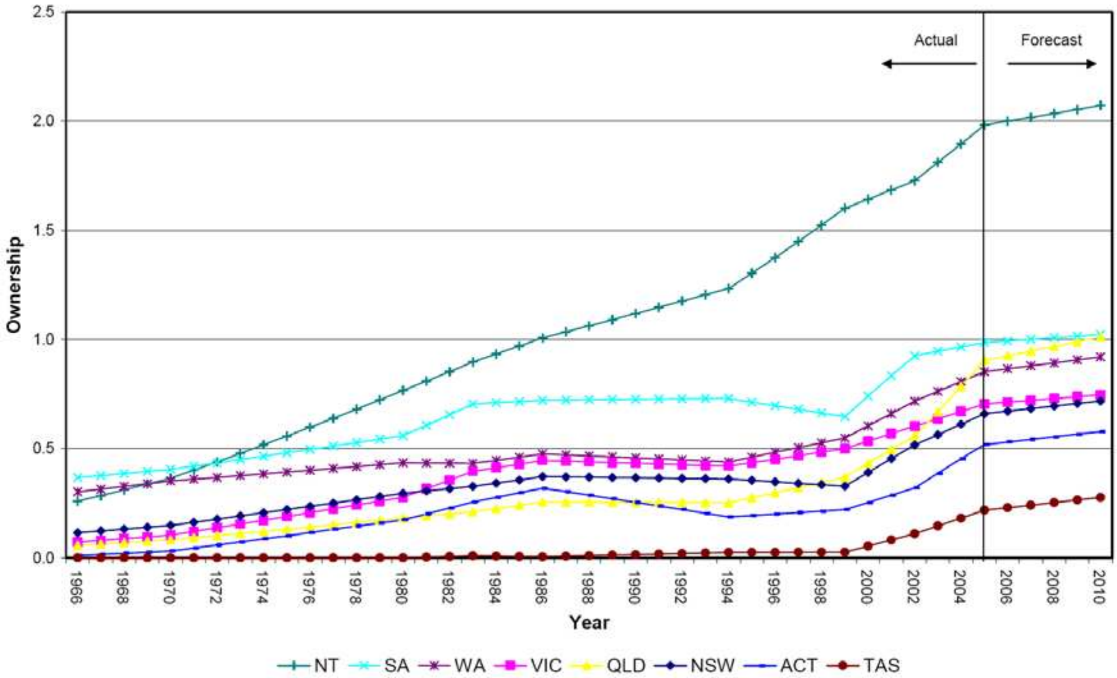
However, Origin Energy (2007) agrees but NGF disagrees with the phasing out of electrical hot water systems. NGF states that water heating accounts for 30% of household electricity use but only 6% of total stationary energy use. Additionally, NGF calls for fuller consideration of the impact of the phase out on peak and off peak electricity use, electricity costs and prices and water use. These electrical hot water systems provide a use for electricity generated during the off peak periods. There are strong financial incentives for coal generators and some gas generators to maintain this off peak load to avoid considerable shutdown and startup costs. Section 6.12 discusses the requirement to maintain this off peak load or a baseload to support coal as a potential form of maladaptation to climate change.

Both Origin Energy (2007) and NGF (2007) express concern about the phase out of incandescent light bulbs being in favour of the phase out but better consultation prior to the phase out may have prevented some adverse and unintended consequences, such as, the poor light rendition and high failure rate of substandard imported compact fluorescent lights (CFL), which caused some people to adopt halogen down lights that have higher energy use than incandescent light bulbs.

The NGF (2007) breaks down the stationary energy use by sector as household 21%, commercial 12% and industrial 67%, claiming a greater focus on energy efficiency in the industrial sector may provide greater gains rather than on the household sector. However, as mentioned, the need to meet peak load drives investment in transmission and generation rather than total energy used. For instance energy use for air conditioners as a percentage of total energy is not significant but air conditioners are primarily used during peak period, which makes the additional load significant.

The MEPS will reduce the amount of energy new air conditioners use and so reduce the demand for electricity. However, Figure 4-6 shows increases in ownership of air conditioners across all states, which will increase demand for electricity. There was a rapid growth in air conditioner ownership from 2000 to 2005 when the growth was expected to slow from 2006. This trend is consistent with a slowing increase in demand per capita for electricity over the long-run. The NT shows a considerably different trajectory to the other states but is ignored as it lies outside the NEM region.

Figure 4-6 National Ownership of Air Conditioners by State



(Source: NAEEEC 2006, p. 9)

Decentralised energy can address peak electricity demand brought about by air conditioners. In NSW, a key part of the reason for surging electricity prices is the need to build electricity assets for peak power demand, primarily electric air conditioning, for four days of the year to meet high demand on hot days. $11 billion of network assets is built to meet demand for just 100 hours a year and as much as 25% of electricity costs result from peak demand, primarily electric air conditioning, which occurs over a period of less than 40 hours a year (Dunstan & Langham 2010).

A 2kW reverse-cycle air conditioner costs $1,500 a year to operate and yet imposes costs on the electricity network of $7,000 since it adds to peak demand (DRET 2012). These network costs are not paid by the consumer operating the air conditioner but by all NSW electricity consumers whether or not they own air conditioners. These network costs are significantly amplified by a city such as Sydney. In an alternative solution to building more network infrastructure, the Tri-generation Master Plan (Kinesis Consortium 2012) will displace 542MW of electricity peak demand, primarily electric air conditioning, which all NSW electricity consumers are currently paying for. This is equivalent to taking 271,000 - 2kW reverse-cycle air conditioners off from peak electricity demand.

The changes in building standards have engendered an improvement in new housing energy efficiency. Yates and Mendis (2009, p. 121) discuss how increased urban salinity and ground movement damage induced by climate change will accelerate building stock renewal, leading to a long-run reduction in demand for electricity. However, the projected growth in the number of households exceeds the projected growth in population, which means fewer people sharing a household and resulting in an increase in demand for electricity above population growth. Table 4-6 shows the projected growth in the number of households across the NEM from 2006 to 2030. Table 4-7 shows the projected growth in the number of households above the projected growth in population, which is significant and amenable to modelling. Table 4-7 is the difference between Table 4-6 and Table 4-5.

Table 4-6 Uneven projected household growth from 2006 to 2030 across the NEM

Series II	QLD	NSW	VIC	SA	TAS	ACT	NEM
State	68%	37%	44%	31%	22%	38%	45%
Capital city	66%	40%	50%	31%	28%		46%
Balance of state	70%	32%	31%	32%	18%		43%

(Source: ABS 2010)

Table 4-7 Projected household growth above population growth from 2006 to 2030

Series II - Series B	QLD	NSW	VIC	SA	TAS	ACT	NEM
State	11%	10%	8%	7%	8%	9%	9%
Capital city	9%	8%	9%	6%	6%		8%
Balance of state	13%	12%	11%	11%	10%		11%

The household projection assumptions in Table 4-6 are those for Series II of the ABS (2010). Series II is considered the most likely growth scenario where Series I and III represent lower and higher growth scenarios, respectively. Series I, II and III household projections use the assumptions of the Series B population projection in Table 4-4.

While the number of people per house decreases, Building Research Advisory New Zealand (BRANZ Limited 2007, pp. 28-9) discusses how there is an increase in the size of the average house in Australia where the new standard house has four bedrooms and two bathrooms. The increases in size of house will increase demand for electricity. While house size has become larger, the section size has become smaller, which increases the heat islands effect that is the reduction in greenery around a suburb to moderate temperature swings. The heat island effect will also increase the demand for electricity. But the increase in the number of swimming pools acts to moderate the heat island effect.

4.8 Higher prices and acclimatisation as long run drivers for demand

Australia still enjoys relatively low electricity prices by international standards but the commodity boom has driven prices higher for fossil fuels, which has in turn driven electricity prices higher (Garnaut 2008, pp. 469-70). At low electricity prices people are insensitive to price rises but at higher prices people become much more sensitive to prices increases to the extent that people decrease their use of electricity. The higher price example means that the price elasticity of demand for electricity has increased or is more elastic. The price elasticity of demand is the percentage increase or decrease in quantity demanded in relation to the percentage increase or decrease in price. The higher prices for electricity could see an elasticity of demand operating, which would moderate further increases in demand for electricity.

Climate change is rapid on a geological scale but slow on a human scale. Hence there is ample time for people to acclimatise to changes in climate in the same location, as opposed to people moving to a new location with a different climate and acclimatising to the new climate but taking a few years to adapt to an abrupt locational change. Peoples' ability to acclimatisation will slightly moderate the increase in demand for electricity induced by climate change.

4.9 Conclusion

The first key finding is the requirement to model demand for each node rather than by state. This finding is supported by the following five observations. There is significantly uneven projected population growth within each state, excepting QLD. Sensitivity analysis of demand to temperature shows a discrepancy between state and capital city. There is a significant difference in base temperature between the state and capital city, excepting VIC, which indicates difference in acclimatisation and heat island effects. Additionally, there are uneven weather patterns and climate change projections within each state.

This chapter provides sufficient information to model demand profiles from 2010 to 2030. Section 4.1 discusses the sensitivity analysis and research questions in which the demand profiles are used. In addition to climate change, the projected growth in population and in the number of households will have a significant effect on the NEM. One research question examines the relative impact of climate change to population change whist another question examines a sensitivity analysis of differing population growth.

The second key finding is that institutional fragmentation is hindering the deployment of smart meters and of energy efficiency equipment generally but there are some successful adaptations to climate change namely, MEPS and the E3 star rating. Furthermore, introducing smart meters with in-house-displays before introducing flexible retail pricing would be more conducive to enhancing public engagement. Sections 10.5 and 10.6 further discuss smart meter deployment and institutional fragmentation, respectively.

Additionally, finance is identified as a non-price signal barrier to the deployment of energy efficient equipment. Section 9.2 further discusses this issue.

5. THE IMPACT OF CLIMATE CHANGE ON ELECTRICITY DEMAND: RESEARCH

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This chapter presents original research on the impact of climate change on electricity demand in the NEM. Chapter 4 provides a literature review to inform this original research. The combined literature reviews of the project in Chapters 2, 4, 6, 8 and 10 have identified four maladaptations to climate change in the NEM:

1. institutional fragmentation, both economically and politically;
2. distorted transmission and distribution investment deferment mechanisms;
3. lacking mechanisms to develop a diversified portfolio of generation technologies and energy sources to reduce supply risk; and
4. failure to model and to treat the NEM as a national node based entity rather than state based.

These four maladaptations are the overarching research questions for the project. This chapter forms smaller research questions to address these overarching research questions.

The original research in this chapter addresses maladaptation 4 directly by modelling the NEM as a national nodal entity rather than state based. Appendix B shows the nodal structure used in this project. The reason for using the node based approach or agent based modelling is that the nodes are related via a network of transmission lines and unless the demand at each node is determined, then the network dynamics cannot be determined to reveal any emergent effects. Chapter 7 models generation capacity and the transmission network using the demand data from this Chapter to evaluate the effect of climate change on following economic factors:

- spot price;
- energy generated by type of generator;
- carbon emissions; and
- transmission line congestion.

The overarching research question from the literature review is broken down into three smaller research questions, which are addressed in the subsequent sections:

1. *How does non-scheduled generation affect net demand?*
2. *What model best predicts gross demand for the project's baseline year?*
3. *What are the projected changes in net demand given the project's weather baseline year, emissions scenario, global climate model and non-scheduled generation?*

These research questions are addressed with projections that start in 2009-10 and finish in 2030 using the climate change parameters and the population projections discussed in the Chapters 2, 3 and 4.

The climate change parameters are repeated below for the convenience of the reader.

- carbon emission scenario SRES A1FI;
- GCMs - Worst case (hottest) - CSIRO-Mk3.5;
- environment variables;
    - temperature;
    - solar radiation;
    - relative humidity;
    - wind speed; and
    - rainfall.
- weather profile year for the baseline of this project:
    - financial year 2009-10.

5.1 Gross and net demand difference requiring non-scheduled generation modelling

This section addresses the following research question.

1. How does non-scheduled generation affect net demand?

Bell, Wild and Foster (2013) investigates the transformative effect of non-scheduled solar PV and wind generation on electricity demand. The motivations for the study are twofold, the poor medium term predictions of electricity demand in the Australian National Electricity Market (ANEM) and the continued rise in peak demand but reduction in total demand. A number of factors contribute to these poor predictions, including the global financial crisis inducing a reduction in business activity, the Australian economy's continued switch from industrial to service sector, the promotion of energy conservation, and particularly mild weather reducing the requirement for air conditioning. Additionally, there is growing non-scheduled generation, which is meeting electricity demand. This growing source of generation necessitates the concepts of gross and net demand where gross demand is met by non-scheduled and scheduled generation and net demand by scheduled generation.

In this chapter, the AEMO's "Total Demand" is the "Net Demand" AEMO (2012b, sec. 3.1.2) defines the "Total Demand" in the following way.

> *"Total Demand" is the underlying forecast demand at the Regional Reference Node (RRN) that is met by local scheduled and semi-scheduled generation and interconnector imports after excluding the demand of local scheduled loads and that allocated to interconnector losses.*
>
> *"Total Demand" is used for the regional price calculations in Dispatch, Pre-dispatch and Five-minute Pre-dispatch 5MPD, and to determine dispatch targets for generating units.*

Semi-scheduled wind farms are included in "Total Demand" but non-scheduled wind farms are excluded.

5.1.1 Methodology

The methodology compares the difference between net and gross demand of the 50 demand nodes in the ANEM using half hourly data from 2007 to 2011. Equation (5-1) describes the relationship:

$$d_g(t, n) = d_n(t, n) + (p_s(t, n) + p_w(t, n)) / 1000$$

Where:

d_g = gross demand (MW)
t = time (half hourly)
n = node
d_n = net demand (MW)
p_s = non-scheduled solar power (kW)
p_w = non-scheduled wind power (kW)

Equation (5-1)

The non-scheduled generation is calculated using the Australian (BoM 2012a) half hourly solar intensity, temperature and wind speed data, the Australian (CER 2012) small generation unit (SGU) installations by postcode and the (ABS 2012a) postcode to statistical area translation.

The CER (2012) database excludes larger scale non-scheduled wind generators. Currently, there are 21 non-scheduled operating wind farms with a combined capacity of 1,157 MW. So, the CER (2012) database understates non-scheduled wind generation. The BoM (2012a) wind speed is measured 30 m above ground level, which is suitable for SGU but unsuitable for large wind generators that range between 60 to 140 m above ground level.

Additionally, the CER (2012) database understates the amount of SGU installations because the database actually records renewable energy certificate that have been successfully redeemed, so does not include certificates that are pending registration or have been failed by the CER or its predecessor. Additionally, the RET legislation allows a 12 month creation period for registered persons to create certificates. So, the 2012 figures will continue to rise due to the 12 month creation period.

The CER database provides an aggregate figure of the redeemed certificate for the years 2001 to 2009 and provides monthly data from January 2010 onwards. This entailed some interpolations to convert the SGU kW installation data into half hourly form suitable for this project. The assumption is made that prior to 2006 that there was zero SGU installed. This is not too onerous an assumption as the amount of SGU installed over 2010 and 2011 dwarfs the installations prior to January 2010.

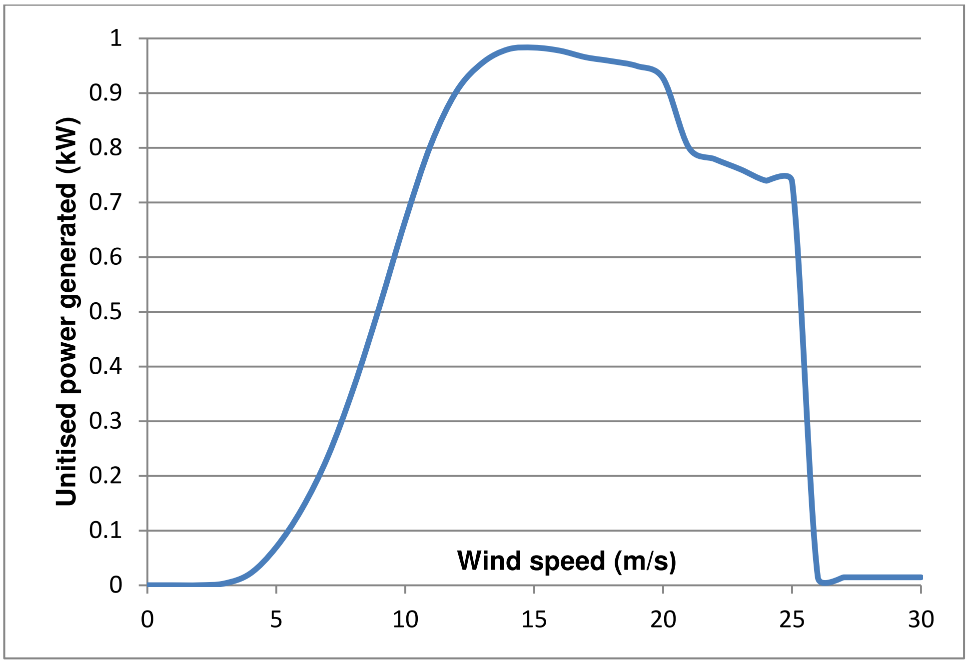
For wind and solar PV generators the post codes of the CER (2012) data are first converted to SA2 (ABS 2012a). The perimeters of SA2 are described by a hierarchical sets of latitudes and longitudes describing smaller areas within Esri shape files (ABS 2011). These perimeter latitudes and longitudes are averaged to produce a latitude and longitude to approximate the centre of the SA2. This centre allows matching with the closest weather stations for power calculations and to find the closest node to attribute the power generated. Approximating an area with a point is justifiable because the SA2s are small areas. SA2 have an average population of about 10,000, with a minimum population of 3,000 and a maximum of 25,000. There are about 2,200 SA2s in Australia.

The CER (2012) database provides the name plate value of the SGU installed but lacks details of the SGU's manufacturer or model. So, simplifying assumptions are made to model generic wind and solar PV generators.

5.1.1.1 Wind generation modelling

A power curve relates the wind speed (m/s) to the power (kW) produced by a wind turbine generator. Figure 5-1 shows the power curve used in this project, which is developed from averaging the power curves of 69 different wind generators sourced from the Idaho National Laboratory (INL 2005).

Figure 5-1 Unitised power curve for generic wind generator



(Source: Bell, Wild and Foster 2013)

Before averaging, the individual power curves are normalised to a value of 1 kW, so the project's power curve represents a generic 1 kW wind generator response to wind speed.

Equation (5-2) shows how the name plate value *n* and power curve function *f* is used to convert the wind speed into power generated for each SA2 containing small wind generators for each half hour.

$$p_w(t, x) = n(t, x) * f(s(t, x))$$

Where:

p_w = power generated by wind (kW generated)
t = time (half hourly intervals)
x = location (SA2 by latitude and longitude)
n = nameplate value (kW installed) *(Source: CER 2012)*
f = power curve (kW generated per kW installed) *(Source: INL 2005)*
s = wind speed (m/s) *(Source: BoM 2012a)*

Equation (5-2)

However, the half hourly data from the weather stations is incomplete, so the four closest weather stations to the centre of the SA2 are used in the calculation where the power per weather station is calculated, which is then averaged. Finally the power by SA2 is converted into power by node.

5.1.1.2 Solar PV generation modelling

This section describes how the half hour solar intensity and temperature readings from BoM (2012a) and the nameplate value of the solar PV from CER (2012) are converted into power (kW) generated per node.

AEMO (2012c, p. 65) notes that a typical solar PV array consists of multiple panels which produce direct current (DC) power. Panel generation output is roughly linear with the incident solar insolation, but is also impacted by the cell temperature. This simple relationship is captured in Equation (5-3), which calculates the usable alternating current (AC) power generated by solar PV for this project and is adapted from the US National Renewable Energy Laboratory (NREL) (Marion et al. 2001). Other factors influence generation, such as, the effect of wind speed on PV module temperature and changes in inverter efficiency with power but Marion et al. (2001) consider these factors are small relative to measurement error, so ignore them in their calculations.

$$p_s(t, x) = d * i(t, x) * n(t, x) * (1 - 0.005 * (T(t, x) - 25))$$

Where:

p_s = usable AC power generated by solar PV (kW)
d = de-rating factor for converting total DC generated into usable AC
t = time (half hourly intervals)
x = location (SA2 using latitude and longitude)
i = solar intensity (kW/m^2)
n = name plate values at STC (kW generated per kW/m^2 solar intensity)
T = ambient temperature (^oC)

Equation (5-3)

The de-rating factor *d* for converting total DC generated into usable AC incorporates losses by inverters and resistance in wiring. The US (NREL 2013) estimates that the de-rating value for the whole of the NEM is 0.77.

Regarding solar intensity *i*, the BoM (2012a) provides solar exposure for each half-hour in solar time in MJ.m-2 per half hour for five weather stations within the NEM region. This solar data is converted kW/m^2 for use as *i* in Equation (5-3). The weather station closest to the SA2 containing the solar PV is used. There are only five weather stations with solar data with half hourly data in the NEM, unlike with the wind generation, averaging over four weather stations is not an option. Hence the missing half hourly data from a solar weather station is interpolated by averaging the previous and next day's data of the same half hour period.

A nameplate capacity *n* of a panel is typically expressed in terms of its output under standard test conditions (STC) to provide a reference point for plant design. The STC are 1000 W/m^2 insolation with a cell temperature of 25°C. The *n* in Equation (5-3) represents the total name plate value present every half hour in each SA2.

Regarding ambient temperature *T* in Equation (5-3), an increase in temperature above 25 °C reduces the power produced by solar PV and a decrease below 25°C increases the power. The average temperature of four weather stations closest to the centre of the ABS statistical area containing the solar PV is used to provide both a more representative temperature of the region and cover any missing data. Temperature has a linear relationship in Equation (5-3), which allows the use of the average temperature across the weather stations.

5.1.1.3 Producing historical half hourly electricity demand by node

Wild and Bell (2011) develop regional load data for Queensland and New South Wales using regional load traces supplied by Powerlink and Transgrid. This data was then re-based to the state load totals published by AEMO (2010a) for the 'QLD1' and 'NSW1' markets. For the other three states, the regional shares were determined from terminal station load forecasts associated with summer peak demand (and winter peak demand if available) contained in the annual planning reports published by the transmission companies Transend in TAS, Vencorp in VIC and ElectraNet in SA. These regional load shares were then interpolated to a monthly based time series using a cubic spline technique and these time series of monthly shares were then multiplied by the 'TAS1', 'VIC1' and 'SA1' state load time series published by AEMO (2010a) in order to derive the regional load profiles for TAS, VIC and SA.

The summer and winter peak load demand were annual values in the transmission planning reports. The cubic spline techniques was used to convert to a monthly share basis with the spline technique joining the summer and winter peak demand periods in terms of regional shares on a calendar basis, summer peak demand was assumed to occur around December to January and winter peaks June to July. The state totals were half hourly and would encompass actual high peak demand in summer and winter – these representing high half hourly demand values. For each month, the method applied the same regional share values which changed on a month by month basis as determined by the cubic spline technique.

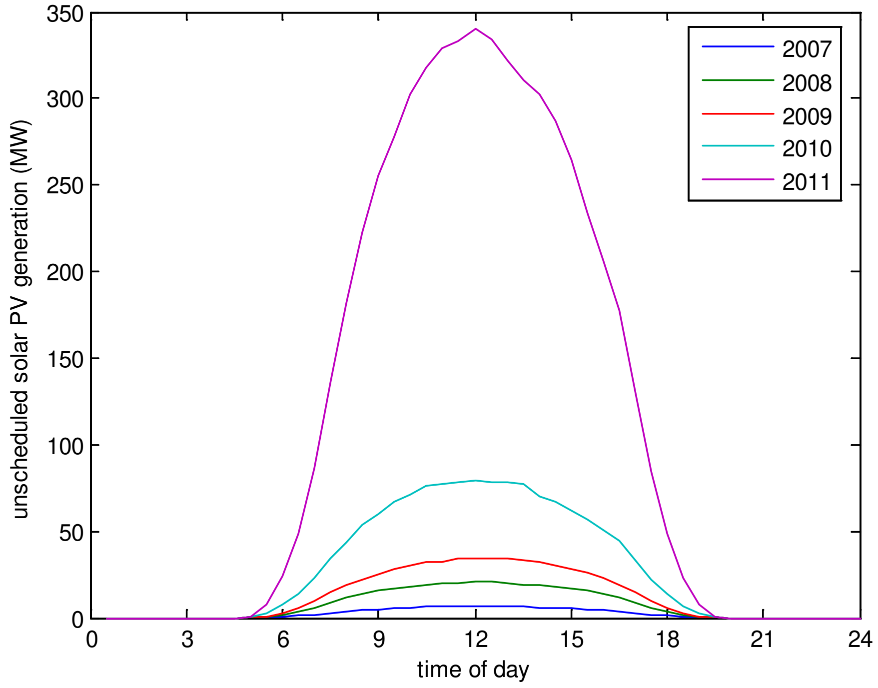
5.1.2 Results

The first section relates gross demand to net demand using the non-scheduled SGU. The second section looks at the effect of non-scheduled generation on peak demand. The third section views intermittency.

5.1.2.1 Relating gross demand to net demand using non-scheduled SGU

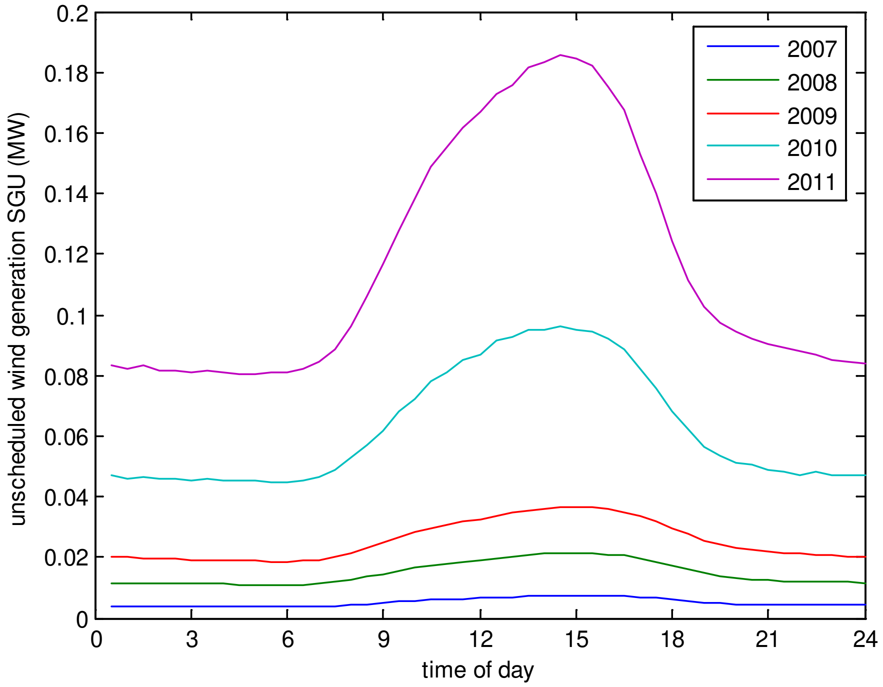
Figure 5-2 and Figure 5-3 shows the NEM's daily average non-scheduled generation from solar PV and wind SGU. The drastic increase in 2011 is notable.

Figure 5-2 NEM's daily average non-scheduled solar PV generation for 2007-11



(Source: Bell 2013)

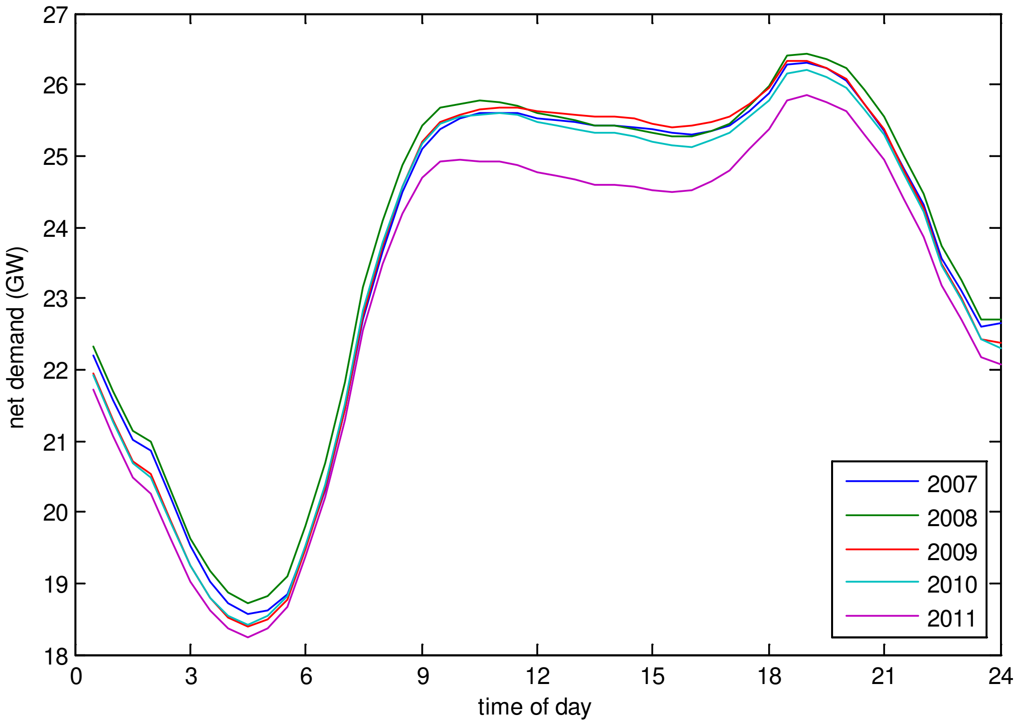
Figure 5-3 NEM's daily average non-scheduled wind generation (SGU) 2007-11



(Source: Bell 2013)

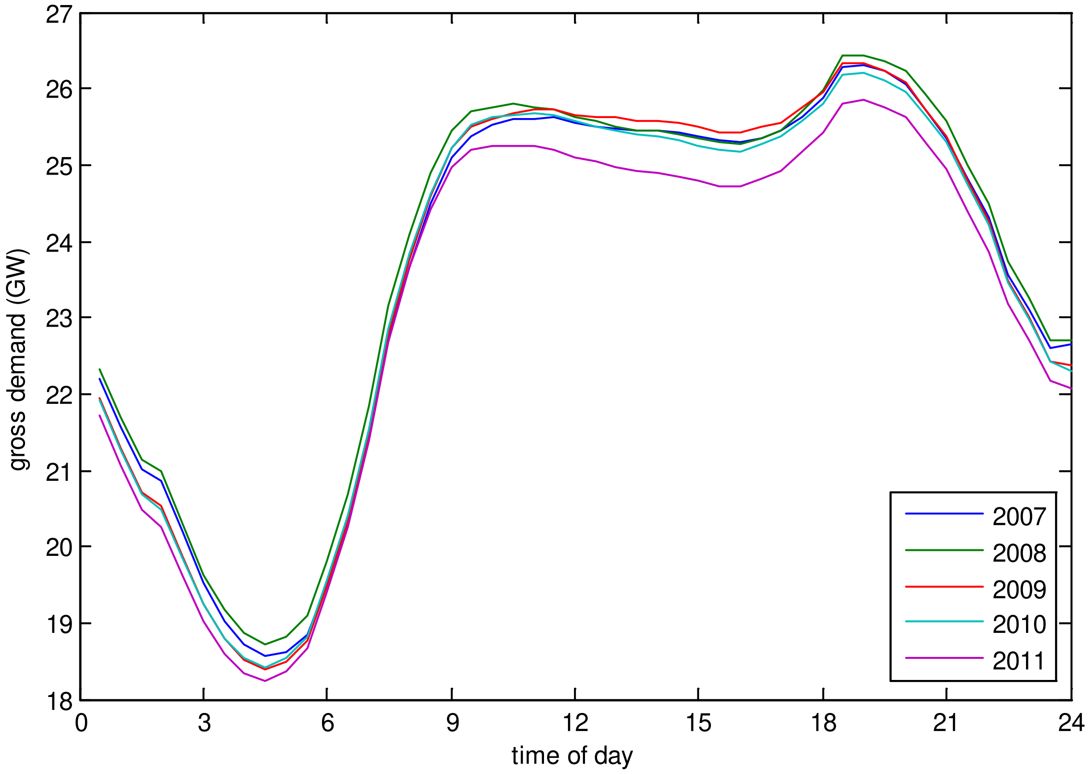
Figure 5-4 and Figure 5-5 show the NEM's daily average net and gross demand. Notable is the difference between gross and net demand in 2011 and previous years.

Figure 5-4 NEM's daily average net demand for 2007-11



(Source: Bell 2013)

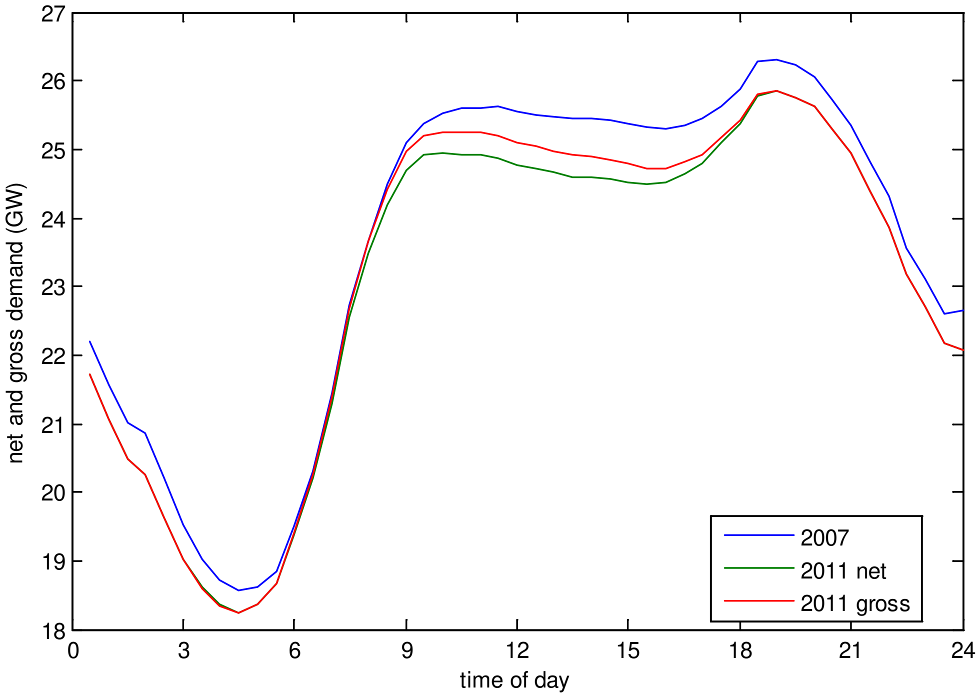
Figure 5-5 NEM's daily average gross demand for 2007-11



(Source: Bell 2013)

Figure 5-6 compares the daily average net and gross demand for 2011 with 2007. The gross and net demand in 2007 is similar, so only one line is necessary to represent both.

Figure 5-6 Comparing daily average gross and net demand for 2007 & 2011

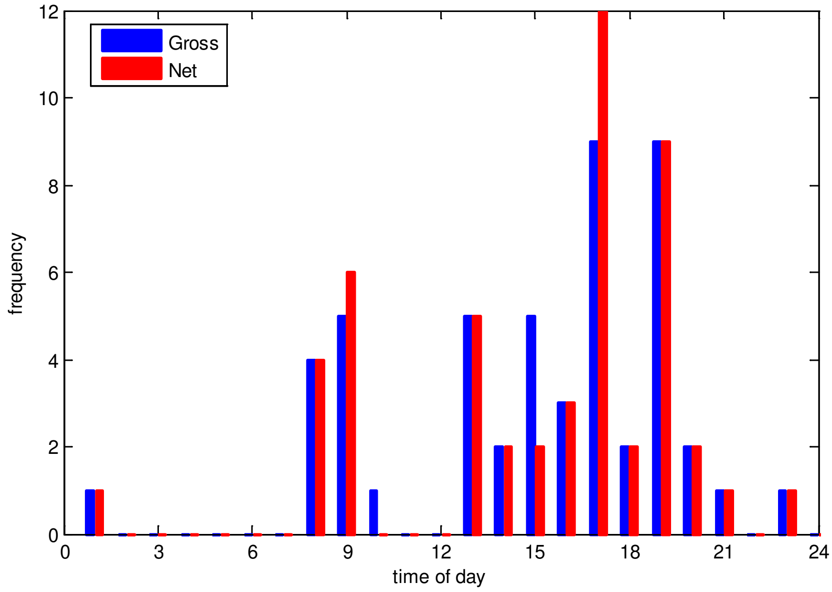


(Source: Bell 2013)

5.1.2.2 Gross and net peak demand

The significance of framing discussion of demand in terms of gross and net becomes apparent when considering the effect of non-scheduled SGU on peak demand. Figure 5-7 shows the distribution of the peak loads by time of day for the maximum peak loads from 2007 to 2011 at each node in the NEM. At 15:00 the disparity between gross and net demand shows the success of SGU in addressing peak demand. However at 17:00 when framing the discussing in terms of net demand non-scheduled SGU appears less effective at addressing peak demand. The net demand analysis, however, misses the point that non-scheduled generation has already addressed some peak demand issues and by doing so makes the remaining peaks in net demand peaks appear more prominent.

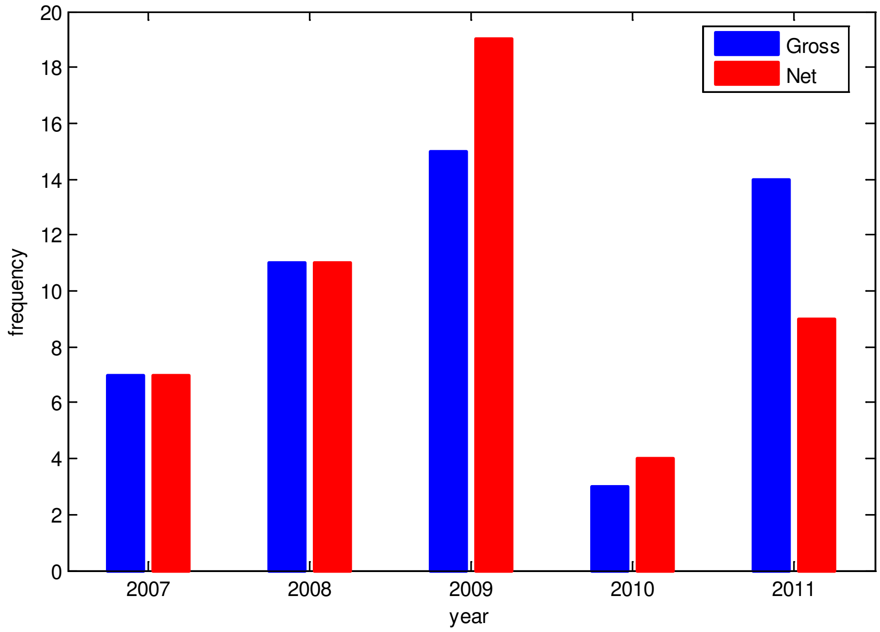
Figure 5-7 Distribution by time of day of the maximum peak loads from 2007 to 2011 at each node in the NEM



(Source: Bell, Wild and Foster 2013)

Figure 5-8 shows the distribution of the peak loads by year for the maximum peak loads from 2007 to 2011 at each node in the NEM. The frequency of maximum peaks for net demand between the years 2011 and 2009 shows the greatest disparity. Using net demand to frame the discussion could misattribute the decline to mild weather in 2011 compared to 2009. Using a gross demand analysis shows that much of the decline in the frequency of peak demand is attributable to non-scheduled SGU.

Figure 5-8 Distribution by year of the maximum peak loads from 2007 to 2011 at each node in the NEM

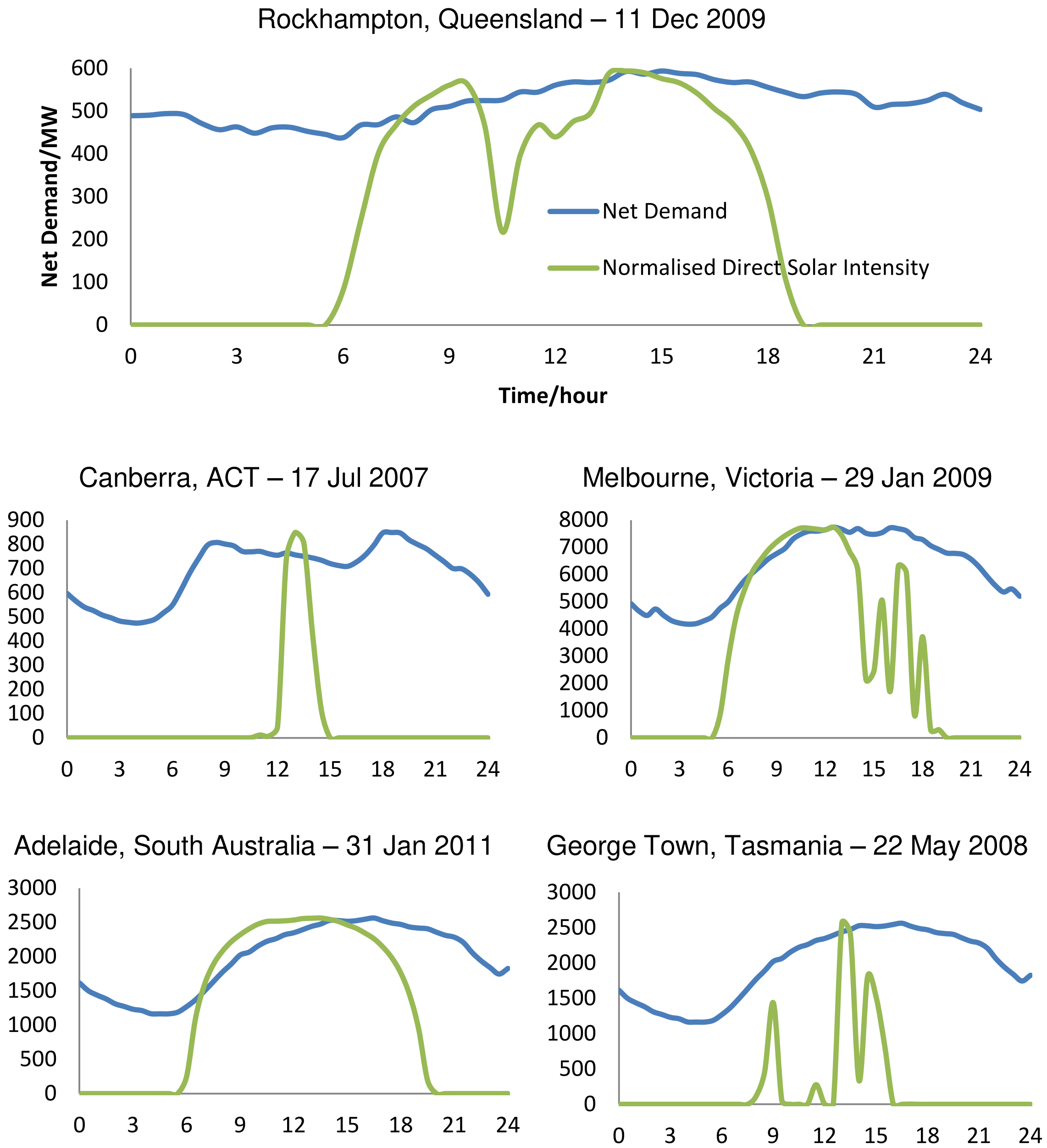


(Source: Bell, Wild and Foster 2013)

5.1.2.3 Intermittency and solar PV matching peak demand

Figure 5-9 compares the normalised direct solar intensity against the highest peak demand day over the period 2007 to 2011 for five nodes in the NEM. These five demand nodes in the NEM are chosen because they are the closest nodes to the only Australian weather stations that provide half hourly solar intensive reading within the NEM.

Figure 5-9 Comparing normalised direct solar intensity to the highest net peak demand day in 2007-2011 at 5 nodes in the NEM



(Sources: BoM 2012b; Wild & Bell 2011)

Table 5-1 matches the weather station with the nodes in Figure 5-9. The nodes Rockhampton, Melbourne and Adelaide and their weather stations at their local airports provide a good match. However, the node Canberra and its closest weather station at Wagga Wagga are about 200 km apart and the node George Town and its closest weather station Cape Grim are about 250 km apart. This separation must be considered when interpreting Figure 5-9.

Table 5-1 Matching the NEM nodes and weather stations that provide half hourly solar data

Node	Weather station
Rockhampton, Queensland	Rockhampton Aero
Canberra, ACT	Wagga Wagga
Melbourne, Victoria	Melbourne Airport
Adelaide, South Australia	Adelaide Airport
George Town, Tasmania	Cape Grim

(Source: BoM 2012b)

5.1.3 Discussion

Figure 5-6 shows that non-scheduled generation goes some way to explain the reduction in net demand since 2007. This effect will be more pronounced in 2012 as the installation of solar PV has substantially increased. The CER is still receiving data on installation for 2012. Additionally, Figure 5-6 shows a reduction in demand between 2007 and 2011 in the early hours of the morning and late evening. This period is when electric hot water heaters use off peak power. Modelling increase in installations of solar hot water heater could explain much of this decrease in demand.

Renewable energy is having a major effect on the net demand curve and helps explain some of the apparent decrease in demand. Introducing the concept of gross demand helps frame the discussion of changes in demand on the NEM in a clearer fashion. There are degrees to the extent that net demand could be grossed up by including the following factors:

1. non-scheduled generation;
2. solar hot water; and
3. energy efficiency.

These are given in order of ease of calculating the direct effect on the demand. As in this section the wind speed and solar intensity can be used directly to calculate power generated at a specific time, which can then simply be used to gross up the net demand curve by adding the power to the net demand curve. The effect of solar hot water heating on net demand is not as simple a relationship. The solar hot water heater replacing electric hot water heater is an indirect relationship, which would require calculating the power that would have been used by the displaced electric water heaters. This displaced power could be used to gross up the net demand curve. Finally, the effect of energy efficiency on net demand is the most difficult to calculate. There is a two per cent turn over in housing stock every year, which will improve the efficiency of electricity use in buildings generally. In addition, there is the more rapid turnover of electric appliances. Attributing energy efficiency effects to the time of the day is left for further research.

Peak demand drives the requirement for new network infrastructure. The analysis of Figure 5-7 and Figure 5-8 shows the misleading conclusions that can arise from failing to incorporate non-scheduled SGU in analysis of peak demand.

Misleading conclusions can manifest in two ways by:

- underestimating the effectiveness of non-scheduled SGU in addressing peak demand by focusing on the remaining net demand peaks; and
- mis-attributing the effectiveness of non-scheduled SGU to other factors.

Figure 5-9 compares solar intensity with net peak demand days. Bear in mind that the net demand curves are shown here, so solar PV has already shaped these curves. In the summer months solar provides quite a good match with net demand. However, there are two considerations that make the match less than ideal:

- intermittency; and
- the mismatch between the peak solar intensity around midday and peak demand in summer around 3 to 4 pm.

This mismatch and intermittency can be addressed with energy storage but there needs an incentive for non-scheduled SGU to install energy storage. Time of supply payment would provide such an incentive. This issue is discussed in detail in Bell and Foster (2012). Additionally, time of use charges would encourage people to shift demand from peak periods.

5.1.4 Conclusion

The section has two conclusions.

Firstly, a requirement for policy to target the growth in peak demand via time of supply feed-in tariff for small generation units and time of use charges. The time of supply feed-in tariffs are intended to promote the adoption of storage technologies, which in turn, will help with intermittency. Time of use charges and time of supply payments encourage demand side participation and management.

Secondly, modellers of electricity demand consider both net and gross demand in their forecasts to improve forecasts and insight into the dynamics operating in the electricity market. Modellers considering both net and gross demand are required to model non-scheduled generation. Meeting this second conclusion has the following requirements:

- more comprehensive solar intensity data be provided by the BoM, and
- AEMO provide data in GIS format of each demand region’s shape using the Australian Statistical Geography Standard developed by the ABS to enable easier integration of large quantities of geographic data from a number of sources.

5.1.5 Further research

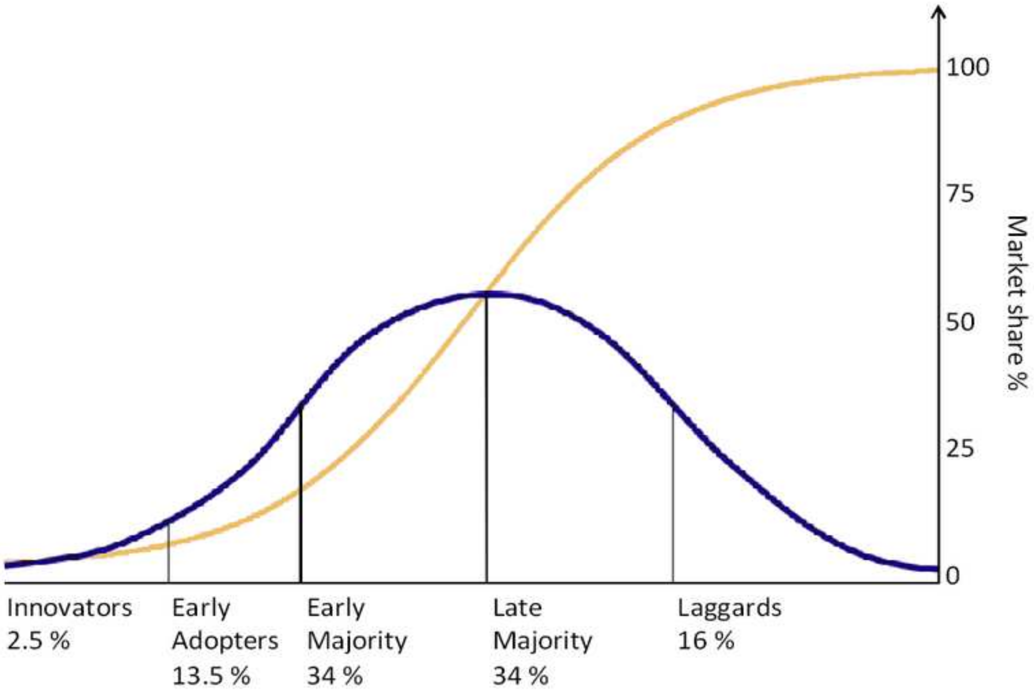
5.1.5.1 Solar hot water, small hydro and energy efficiency

Bell, Wild and Foster’s (2013) study is instrumental to a range of further research. Other sources of non-scheduled generations should be considered to form a more comprehensive concept of gross demand, for instance, solar hot water and small hydro. Replacing electrical hot water heaters with solar hot water heaters reduces the overnight demand, which may provide a considerable transformative effect on net electricity demand. In addition, energy efficiency is meeting demand for electricity; incorporating energy efficiency would form an even more comprehensive concept of gross electricity demand and could help improve longer term electricity demand projections.

5.1.5.2 Sensitivity analysis of increases in solar PV and wind generation

This project's modelling uses the increases of solar PV and wind for the financial year 2009-10 in all the demand projections 2010-30. This consistency allows inter-year comparisons where any change is purely due to climate change. However, the number of solar PV installations is rapidly increasing. Bell and Foster (2012) discuss how all new technologies follow S-shaped diffusion curves that can usually be tracked by a nonlinear logistic or a Gompertz function, see Figure 5-10. From this baseline of 2009-2010 the sensitivity of net demand to increases in solar PV and wind generation can be evaluated where the diffusion of innovation follows a Gompertz function. This can be simplified by evaluating the sensitivity of net demand to various penetrations of solar PV in 2030.

Figure 5-10 Diffusion of innovation



(Adapted from: Rogers 1962)

5.1.5.3 Improving the use of the limited solar intensity data

There are only five weather stations with half hourly solar intensity data in the NEM. However there are many more weather stations with daily global solar exposure data. Using both datasets could improve the modelling of the half hourly solar intensity at other locations.

This can be achieved by using the latitude of a location between two half hourly solar weather stations in a weighted average and the resultant average scaled by the total daily solar intensity of a nearby weather station of similar latitude.

In the longer term, the Australian Renewable Energy Agency (ARENA 2012) project titled "Australian Solar Energy Forecasting System" (ASEFS) awarded to CSIRO will go some way to addressing this issue.

In a similar vein, for wind generation there is the AEMO's (2011c) "Australian Wind Energy Forecasting System" (AWEFS) project awarded to a consortium of European companies called ANEMOS.

5.1.5.4 Using GIS to improve weather station, post code and node matching

This project uses the longitude and latitude of the weather stations, demand nodes, and the weighted centres of ABS statistical areas to match entities. The weather stations are points, so the longitude and latitude method is appropriate. However, the demand node and the ABS statistical areas are unevenly shaped regions. This will create inaccuracies in matching entities. For instance a demand node region could be long and thin, so the weather stations lying closest to the centre of the demand node region may well be outside the region. This problem also affects population by statistical area.

Using a GIS would eliminate this problem. The ABS population data already comes in GIS format and the small generation name plate values by postcode regions can be transformed into ABS statistical regions. However, the demand node regions are publically unavailable in GIS format. These maybe privately available within individual network service providers or retailers but a comprehensive publically available GIS format mapping of the demand node regions is lacking. Provision of such information is a near public good and better provided by the ABS or AEMO. Provision is a near public good because provision lacks rivalry of use, as many people can use the same information without exhausting supply, but people can be excluded from provision. Provision of the data would add to the intellectual infrastructure of Australia.

5.1.5.5 Clarify semi-scheduled generation's role in gross and net demand

Gross demand includes transmission and distribution losses and is met from all sources of generation including, SGU and larger scale non-scheduled, semi-scheduled or scheduled generation. Semi-scheduled generation role requires clarifying whether it is included within net demand or only within gross demand.

5.2 Modelling demand for the baseline weather year 2009

This section addresses the following research question.

2. *What model best predicts gross demand for the project's baseline year?*

The section derives models to predict the gross electricity demand for each of the 50 demand nodes of the NEM, which builds on the work in the previous sections. Appendix B provides network diagrams of these 50 demand nodes and the 3 additional supply only nodes. Sections 3.1 selects a baseline weather year that is the financial year 2009-10. Section 3.2 selects the annual average projections to 2030 for the GCM that is CSIRO-Mk3.5 using the emission scenario A1FI. Section 5.1 calculates the contribution of non-scheduled SGUs from solar PV and wind generation to add to net demand to find gross demand.

5.2.1 Methodology

The methodology uses neural networks to develop a model to predict the gross demand for the 50 demand nodes of the NEM for the financial year 2009-10. Neural networks are a standard tool in electricity demand predictions and are particularly good at modelling non-linear systems such as electricity demand (Deoras 2010). Neural networks help reduce the model variance that measures the goodness of fit between the model's demand prediction and the actual demand. Producing the demand models is an iterative process of two stages involving calibration and prediction. First a model of gross demand is calibrated using data from the financial year 2009-10. Secondly the model's predictive performance is tested using data from July 2010. Combinations of variables are tested in this iterative process until the model with the best predictive performance is determined within the time available. Equation (5-4) shows the best model developed for this project using the demand models from Hyndman and Fan (2009) and Deoras (2010) as the initial starting point.

$$d_g(t, n, w) = f(\ T(t, n, w), T_d(t, n, w), T_i(t, n, w), h(t, n, w), h_{-1}(t, n, w), \ldots \\ i(t), p(t, n), dow(t), hol(t, n), s(t, n, w)\ )$$

Where:

d_g = gross demand (MW)
t = time (half hourly intervals)
n = node [1,…, 50]
w = weathers station
f = neural network function
T = temperature
$T_d = T_{-d}, T_{-2d}, T_{-3d}, T_{-4d}, T_{-5d}, T_{-6d}$, the temperature lagged by 1 to 6 days
$T_i = T_{-i}, T_{-2i}, T_{-3i}, T_{-4i}, T_{-5i}, T_{-6i}$, the temperature lagged half hourly intervals
h = humidity
h_{-1} = humidity lagged one half hourly interval
i = [1,…,48] representing the 48 half hourly intervals in a day
p = population
dow = [1,…,7] day of the week
hol =[0,1] – national and state holidays represented by 1, otherwise 0.
s = winds speed (m/s)

Equation (5-4)

The five weather stations *w* closest to a node *n* are selected for modelling. Equation (5-5) shows how the five weather station demand models are averaged to form the demand model for the node. This model averaging serves to improve predictive performance and to cover missing weather data. There is some interpolation of the weather station data but only for a missing half hours' worth of data. If an hour or more of data is missing, this missing data is not interpolated.

$$d_g(t,n) = \sum d_g(t,n,w) / 5$$

Equation (5-5)

In Equation (5-4), the neural network function *f* relates the environment variables (*T, h* and *s*), population *p*, day of the week *dow*, holidays *hol* and periods *i* to the gross demand d_g.

The temperature *T*, humidity *h* and wind speed *s* come from the weather stations *w*. The temperature lagged by one to six days T_d captures heat island effects. The temperature lagged by one to six half hourly periods T_i captures the sluggish response of individuals to changes in weather variables.

The interval *i* represents the half hourly intervals in a day numbered from one to 48. The day of the week *dow* is represented by the numbers one to seven. The day of the week and the interval capture habitual cycles.

The population *p* is developed from ABS (2012c) by SA2 from 2001 to 2011. This data is interpolated to provide half hourly population data. The longitude and latitude of the centre of SA2 is used to associate the population to closest demand node.

The holidays *hol* is developed from the national and state holidays downloaded from Time and Date AS (2012). All demand nodes took the value of one for a national holiday and took the value of one for state holidays if the node is located within the state, otherwise took the value of zero. Tasmania's state holiday is celebrated in the north and south on different days and called 'Recreation Day' and the 'Royal Hobart Regatta holiday', respectively. The Tasmanian Government's (2012) workplace standards data is used to attribute the appropriate Tasmanian state holiday to the demand nodes.

The Gross State Product (GSP) *g(t, n)* is developed from ABS (2012e) the Australian National Accounts: State Accounts but rejected as adding little or no predictive value to the model. The description is added here for completeness for discussion later.

5.2.2 Results

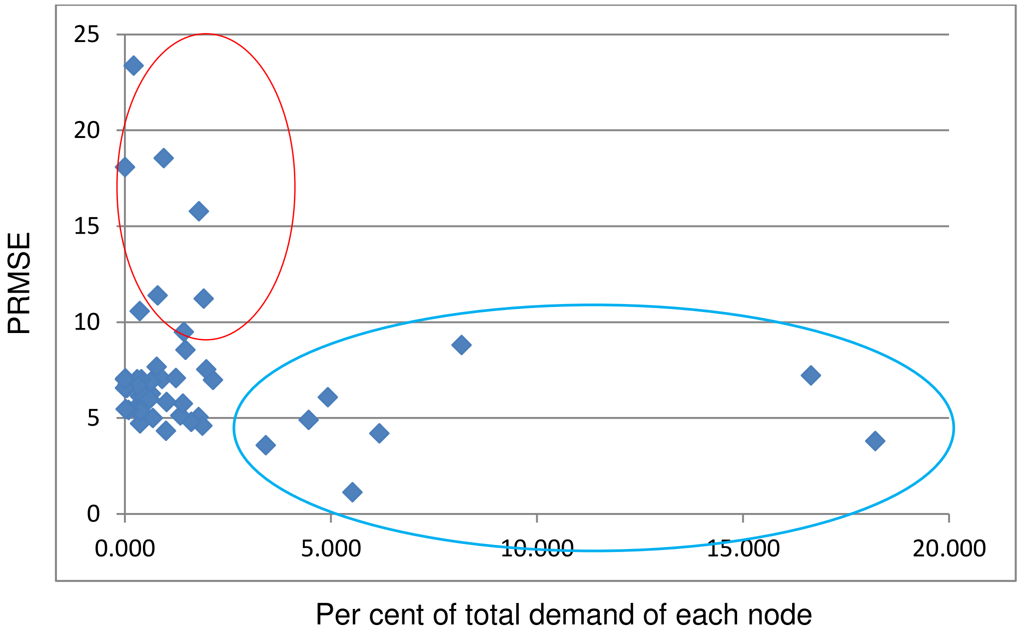
Table 5-2 shows the square root of the mean of the square of the error (RMSE) between the modelled demand and actual demand for calibration, prediction and both periods for the 50 demand nodes in the NEM. The calibration period is the financial year 2009-10 the prediction period is July 2010. The percentage RMSE (PRMSE) is the RMSE divided by the mean of the demand for the respective periods divided by 100. Demand nodes 10, 23 and 28 are pseudo nodes used to model the demand from pump hydro storage and are modelled in Chapter 7 on electricity supply. The column that presents the percentage of total net demand for the financial year 2009-10 is added to provide an indication of the relative size of the nodes. The rows of the eight largest nodes are coloured blue and the rows of the nodes with the highest PRMSE are coloured red. These two groups are mutually exclusive. Figure 5-11, developed from Table 5-2, shows the PRMSE versus the percentage of the total net demand for the financial year 2009-10. 42 of the nodes in the NEM including the largest eight nodes have a PRMSE less than nine. In comparison, the eight nodes with a PRMSE greater than nine are all less than 2% in total net demand.

Table 5-2 Errors in fitting the models for each node for the baseline weather year

node	RMSE Calibration	RMSE Prediction	RMSE Both	PRMSE Calibration	PRMSE Prediction	PRMSE All	% total net demand
1	9.7	9.2	9.6	4.1	4.3	4.2	0.996
2	29.9	50.3	32.0	7.1	15.8	7.7	1.800
3	28.3	27.5	28.3	8.2	8.6	8.2	1.475
4	21.5	21.1	21.5	5.1	5.1	5.1	1.791
5	15.3	14.6	15.3	1.2	1.1	1.2	5.521
6	11.5	12.1	11.5	6.3	7.7	6.4	0.774
7	3.9	17.9	6.2	7.8	23.4	12.1	0.211
8	14.7	21.3	15.3	7.9	11.4	8.2	0.794
9	50.3	50.6	50.3	4.8	4.9	4.8	4.457
10							
11	66.4	58.3	65.8	4.6	4.2	4.6	6.178
12	19.6	19.5	19.6	4.4	4.6	4.4	1.884
13	7.5	9.8	7.7	5.1	6.3	5.2	0.633
14	13.2	17.1	13.5	6.2	7.0	6.3	0.903
15	6.6	8.2	6.7	6.0	6.7	6.1	0.465

node	RMSE Calibration	RMSE Prediction	RMSE Both	PRMSE Calibration	PRMSE Prediction	PRMSE All	% total net demand
16	27.7	39.2	28.8	12.5	18.5	13.1	0.943
17	51.9	176.2	70.1	2.7	8.8	3.6	8.172
18	25.1	22.1	24.8	8.6	7.1	8.5	1.241
19	212.0	311.1	221.3	5.4	7.2	5.6	16.652
20	12.8	12.9	12.9	8.6	6.9	8.5	0.634
21	21.9	33.3	23.0	6.5	9.5	6.8	1.433
22	24.5	39.3	26.0	4.9	7.0	5.1	2.138
23							
24	8.1	6.3	8.0	9.4	6.1	9.1	0.367
25	8.9	10.9	9.0	10.5	10.6	10.5	0.360
26	30.9	42.3	31.9	6.7	7.5	6.8	1.974
27	28.7	52.2	31.2	6.4	11.2	6.9	1.913
28							
29	4.8	4.8	4.8	5.5	4.7	5.4	0.369
30	3.2	3.6	3.3	5.7	5.5	5.7	0.241
31	13.2	16.2	13.4	5.5	5.8	5.6	1.015
32	0.2	0.2	0.2	6.6	7.1	6.7	0.014
33	183.6	173.3	182.8	4.3	3.8	4.3	18.208
34	20.6	21.1	20.6	5.5	4.8	5.4	1.612
35	36.0	31.2	35.6	4.5	3.6	4.4	3.422
36	6.8	7.3	6.8	7.2	7.0	7.2	0.402
37	4.3	5.6	4.4	6.1	7.0	6.2	0.301
38	68.5	78.4	69.3	5.9	6.1	5.9	4.925
39	0.8	0.9	0.8	6.2	6.6	6.2	0.053
40	6.7	7.3	6.8	6.3	6.2	6.3	0.459
41	1.0	1.1	1.0	6.7	6.8	6.7	0.065
42	5.4	5.6	5.4	7.2	6.7	7.1	0.322
43	15.3	15.6	15.4	4.9	5.1	4.9	1.346
44	4.1	5.2	4.2	4.9	5.5	5.0	0.353
45	7.4	8.6	7.5	4.6	5.0	4.6	0.682
46	5.0	4.7	5.0	5.6	5.4	5.6	0.381
47	7.3	11.3	7.7	5.2	6.0	5.3	0.602
48	1.0	1.2	1.1	4.9	5.4	5.0	0.090
49	0.0	0.0	0.0	5.0	6.6	5.2	0.001
50	0.0	0.1	0.0	11.3	18.1	12.2	0.001
51	0.2	0.2	0.2	5.1	5.5	5.1	0.016
52	16.9	24.4	17.6	5.1	5.7	5.2	1.407
53	0.1	0.1	0.1	5.4	7.0	5.5	0.007

Figure 5-11 PRMSE versus percentage of total demand in 2009-10 for each node



5.2.3 Discussion

The models for 42 nodes, including the eight larges nodes, have a PRMSE less than 9% and the models for the eight nodes whose PRMSE is greater than nine are small nodes being less than 2% the total demand of the NEM for the financial year 2009-10.

5.2.3.1 Inter study comparison

Deoras (2010) discusses how his neural network model of electricity demand has a PRMSE of 4%. In comparison the average fit obtained for this project's demand models is 7%. Using, an average weighted by the nodes' fraction of NEM's total demand would reduce this 7%.

However, there are a further four dimensions that help explain why the demand model of Deoras (2010) has better predictive performance than the average of this project.

- nodes whose demand drivers are not environment variables;
- reduced number of environment variables;
- modelling nodal demand data rather than aggregate data; and
- the development of the demand data.

The model in Equation (5-4) assumes that weather variables are the main driver for demand. However the eight nodes with the highest PRMSE marked in red, are associated with rural areas which have relatively small residential population, so only a small portion of the demand is sensitive to the environment variables. In addition, these eight highest PRMSE nodes have relatively large industrial demand that is unresponsive to changes in the environment variables. Modelling the industrial component could reduce the PRMSE for these eight nodes.

The model developed in this section is used in the next section. This future use limits the environment variables available for modelling to temperature, humidity, and wind speed because the project's GCM has projections for these variables. Chapter 2 discusses how environment variable are interdependent, so requiring the use of environment variables from a single GCM to ensure internal consistency. In further research, Section 5.5 discusses potential ways to extend the number of internal consistent environment variables. This further research could reduce the PRMSE for all nodes.

This study models 50 demand nodes rather than at the state level or the whole NEM. It is easier to fit models to highly aggregated data. However, these demand centre nodes are related via a network of transmission lines to supply nodes in Appendix B and only if the demand at each node is determined, can the supply response and network dynamics be modelled to determine emergent properties. To model these network dynamics, Chapter 7 requires that this chapter provides the demand at each node in Appendix B.

The AEMO provides demand data in accurate aggregated state level form. However, as discussed Chapter 7 requires that the demand data be disaggregated to nodal level shown in Appendix B. Section 4.1.3 describes the process undertaken by Wild and Bell (2011) to develop the demand profiles for the 50 demand nodes. These transformations may carry some inaccuracies, which may be more significant for the smaller nodes. The AEMO is reluctant to produce node base demand profiles, as there are privacy issues on the smaller nodes with a few large consumers.

5.2.3.2 Gross domestic product, gross state product and population

The GDP and GSP are often used in longer term demand forecasts.

However, adding GSP to the model has little effect on the PRMSE. Three reasons can explain this ineffectiveness:

- the Global Financial Crisis (GFC) started in late 2007 and the aftermath is still creating a volatile economy;
- the GSP data available is annual so lacks the resolution to capture the volatility; and
- the volatility and nature of this variables as a ‘flow’ instead of a ‘stock’ variable make interpolation unsuitable.

Mainstream economics has been spectacularly unsuccessful in modelling GDP both in predicting the GFC and its aftermath. A notable exception is Keen (1995) who had success in predicting the GFC. He is also successful in modelling GDP in the aftermath of the GFC. However, Keen only works at the national level, which makes his work unsuitable for this project, which investigates demand at the nodal regions.

The inclusion of GSP is not critical to this project, as the project effectively models the financial year 2009-10 and repeats the year adjusted for change in environment variables to focus purely on climate change effects, which makes long term GSP projections unnecessary.

Similarly, the inclusion of population is not critical to this project. However, including a population projection did help reduce PRMSE for some nodes. Population and GSP data contrast considerably as population data is available at much higher geographic and temporal resolution and is much less volatile. These factors combine to make population more amenable to interpolation.

5.2.4 Conclusion

This section provides suitable models for use in Section 5.3. Refinements to these models are discussed in further research.

5.2.5 Further research

5.2.5.1 Increase the number of environment variables

The environment variables used in Equation (5-4) are restricted to the environment variables available in the GCM projections. Rainfall is available in the GCM projections but not traditionally used in electricity demand forecasting. A pragmatic approach is to add rainfall to Equation (5-4) and test the change in the predictive performance (PRMSE) induced by the alteration. In contrast, wet bulb temperature is used in electricity demand forecasting but is unavailable in the GCM projections. However wet bulb temperature can be calculated from humidity and temperature. Again, a pragmatic approach is to test the change in predictive performance by adding wet bulb temperature to Equation (5-4).

5.2.5.2 Investigate alternative drivers for electricity demand

The models of the eight nodes with the highest PRMSE are prime candidates for further investigation. Investigating the demand for electricity from industry within these nodes may help improve the predictive performance of the models for these nodes.

5.2.5.3 Does modelling gross rather than net demand reduce PRMSE?

Test the improvement in predictive performance of modelling gross demand over net demand. This testing will evaluate the usefulness of modelling non-scheduled generation for demand predictions. This section investigates the year 2007-2011 but the installation of solar PV roughly doubled from 2011 to 2012. The difference between gross and net demand is growing each year.

5.2.5.4 Does modelling GDP rather GSP help reduce PRMSE?

The GDP data is available quarterly in contrast the GSP data is only available annually. Using higher temporal resolution and forfeiting geographic resolution may help reduce the PRMSE of the models.

5.3 The effect of climate change on electricity demand by node

This section addresses the following research question.

3. *What are the projected changes in net demand by node given the project's baseline weather year, emissions scenario, global climate model and non-scheduled generation?*

The section discusses the effect of climate change on electricity demand by node and builds on the previous sections using:

- the weather baseline year selected in Section 3.1;
- the GCM and emissions scenario selected in Section 3.2;
- the non-scheduled SGU in Section 5.1; and the
- demand models developed for each node in Section 5.2 for the baseline weather year.

5.3.1 Methodology

The methodology has two main steps;

1. take the environment variables in each weather station for the baseline weather year 2009-10 and increment by the GCM projections to form projections of the environment variables in each weather station from 2010-11 to 2030-31; and
2. use these newly formed projections of the environment variables with the demand models developed in Section 5.2 for the year 2009-10 to project the demand from 2010-11 to 2030-31.

The following notes are relevant to steps 1 and 2 above.

5.3.1.1 Make projections of weather station's environment variables

GCM projections from ozClim (CSIRO 2011) are available as change from the base year 1990 to 2020, 2025 and 2030 for the environment variable in Equation (5-4). Section 5.3.3 discusses these projections. The change in environment variable values for the years intervening 1990, 2020, 2025 and 2030 are linearly interpolated. These interpolated GCM projections are rebased from 1990 to this projects baseline weather year 2009. GCM projections at the state level of aggregation are used for this project.

5.3.1.2 Use environment variable projections and models to produce demand projections

This chapter aims to model the effect of climate change on electricity demand by node. To ensure the results reflect only climate change effects all other factors are kept at the baseline weather year values. This means that the values for population, holidays, day-of-the-week and periods for the baseline year 2009-10 are repeated for each of the projected years 2010-11 to 2030-31. This ensures that any spurious day-of-the-week or holiday effects leave the results uncoloured.

5.3.1.3 Compare change in total net demand and total costs from 2009 to 2030

The following results are from analysing two aspects from the effect of climate change on demand projections from 2009-10 to 2030-31:

- growth in demand; and
- growth in peak demand.

These two aspects are important as the total net demand determines the revenue base for the NSPs and the growth in peak demand drives the legal requirement for new infrastructure investments by NSPs, which can in turn drive price rises in the provision of network service per Watt of electricity. Equation (5-6) provides a simple estimate of the percentage change in electricity prices due to climate change. Equation (5-6) makes the simplifying assumption that generators can supply any quantity of electricity at the same price to focus purely on demand change implications. Additionally, the total net demand provides a proxy for total emissions assuming that the ratio of the source of electricity remains constant. Chapters 6 and 7 relax these assumptions and investigate the effect of climate change on the supply of electricity.

Equation 5-6 assumes that NSPs receive a constant return on capital invested, which provides an approximation to the capital expenditure (CAPEX) rules determining profits for NSPs.

$$
\begin{aligned}
TC &= P \times Q \\
TC &= P_o(Q \times o) + P_n(Q \times n) \\
TC &= Q \times ((1\text{-}n)P_o + nP_n) \\
\Delta TC &= \Delta Q + n\Delta P_n \\
P_n &= PD_r / Q \\
TC &= Q + n\,(PD_r / Q)
\end{aligned}
$$

ΔTC = percentage change in Total cost of electricity

Where:

TC = Total cost of electricity
Q = Total net annual demand of electricity
P_n = Price of supply by NSPs
P_o = Price of other non-NSP factors of supply such as generation and retail margin
n = fraction of the cost attributed to NSPs = 0.418
o = fraction of cost attributed to other non-NSP factors
PD_r = Peak demand – the subscript "r" indicates ratcheted peak demand

Equation (5-6)

Chapter 7 specifically models the effect of climate change on transmission utilisation that is electricity transferred between nodes but the effect of climate on distribution that is electricity transferred within a node can readily be approximated by electricity demand at a node. The fraction of the cost attributed to NSPs *n* is estimated at 0.418 (PwC 2011, p. 14). This *n* comprises of distribution and transmission fractions of 0.345 and 0.073 respectively. This high ratio of distribution to transmission makes the simplifying assumption in this Chapter to ignore electricity transmission between nodes not too onerous for an analysis of utilisation. An important consequence of Equation (5-6) is that if the utilisation of the lines remains constant that is PD_r / Q remains constant, there is no change in the price of NSP provision per Watt. However, if the lines become underutilised whether from a decrease on *Q* or increase in PD_r, the cost of NSP provision per unit of electricity will increase. The peak demand *PD* determines new investment in infrastructure in any year. However, if the peak demand the following year is less than the previous year, the capital investment made the previous year is a sunk cost and cannot be undone. This process in effect ratchets investment upwards and helps explain why consumers are unable to fully benefit from reductions in electricity consumption.

5.3.2 Results

Table 5-3 and Table 5-4 show the per cent change in demand and total costs from 2009-10 to 2030-31 by NEM state and demand centre, respectively. Nodes diagrams of the demand centres are in Appendix B. Table 5-3 shows that QLD of the states in the NEM is expecting both highest per cent increase in total demand and in peak demand with the largest per cent decrease in utilisation and increase in totals cost. In contrast, TAS has the largest per cent decreases in total net demand and is the only state with a per cent decrease in peak demand. However infrastructure is a sunk cost, so Tasmania underutilises the existing infrastructure. This underutilisation of infrastructure reduces the cost saving from the reduction in demand.

All states have a per cent reduction in utilisation of the network infrastructure. This has two sources an increase in per cent peak demand in excess of per cent increases in total net demand and a per cent reduction in total net demand. These two sources are epitomised by QLD and TAS, respectively.

Table 5-3 Per cent change in demand and total cost from 2009 to 2030 by state

Per Cent	%Δ Total Net Demand	%Δ Peak Demand	%Δ Peak Demand Ratchet	%Δ Utilisation	%Δ Cost NSP	%Δ Total Cost
	(%Δ Q)	(%Δ PD)	(%Δ PD_r)	%Δ(Q/PD_r)	%Δ(PD_r / Q)	(%ΔQ+n%Δ(PD_r/Q)
QLD	0.81	2.53	2.53	-1.68	1.71	1.52
NSW	0.04	1.24	1.36	-1.30	1.32	0.59
VIC	-0.11	0.82	0.82	-0.93	0.94	0.28
SA	-0.05	1.16	1.16	-1.20	1.21	0.46
TAS	-0.27	-0.41	0.00	-0.27	0.27	-0.15
NEM	0.18	1.37	1.43	-1.23	1.25	0.70

Table 5-4 provides a higher resolution analysis of the data in Table 5-3. The demand centres 10, 23 and 28 are pseudo demand centres used to modelled pumped storage hydro, as shown in Chapter 7. Demand centre one, called Far North, in QLD has the projected highest per cent increase in total costs. Demand centre 26, Canberra, has the projected lowest per cent increase in total costs. 22 of the 50 demand centre have per cent decreases in total net demand but only 15 have per cent decreases in total costs. These are mostly in the more southerly locations. 15 of the 50 demand centres have per cent decreases in peak demand and are mostly in TAS. Five of 50 demand centres have per cent increase in utilisation. South Morton has both the highest per cent increase in peak demand and lowest per cent utilisation.

Table 5-4 Per cent change in demand and total cost from 2009 to 2030 by demand centre

	State	Demand Centre	%Δ Total Net Demand	%Δ Peak Demand	%Δ Peak Demand Ratchet	%Δ Utili-sation	%Δ Cost NSP	%Δ Total Cost
1	QLD	Far North	2.30	2.56	2.56	-0.26	0.26	2.41
2	QLD	Ross	0.89	1.14	1.14	-0.25	0.25	1.00
3	QLD	North	1.57	2.23	2.23	-0.64	0.65	1.84
4	QLD	Central West	0.67	1.09	1.09	-0.42	0.42	0.84
5	QLD	Gladstone	0.11	0.06	0.06	0.05	-0.05	0.09
6	QLD	Wide Bay	0.82	2.97	2.97	-2.09	2.14	1.71
7	QLD	Tarong	0.48	2.32	2.32	-1.80	1.84	1.24
8	QLD	South West	0.09	2.16	2.16	-2.03	2.07	0.95
9	QLD	North Morton	0.91	3.02	3.02	-2.05	2.09	1.79
10	QLD	NM Pseudo						
11	QLD	South Morton	1.00	3.99	3.99	-2.87	2.96	2.24
12	QLD	Gold Coast	0.96	3.21	3.21	-2.18	2.23	1.89
13	NSW	Lismore	0.27	2.10	2.10	-1.80	1.83	1.03
14	NSW	Armidale	-0.44	-2.24	0.00	-0.44	0.44	-0.25
15	NSW	Tamworth	0.55	1.25	1.25	-0.69	0.70	0.84
16	NSW	Liddell	0.32	-0.12	0.00	0.32	-0.32	0.19
17	NSW	Newcastle	0.10	0.79	0.79	-0.68	0.68	0.39
18	NSW	Central Coast	0.62	1.39	1.39	-0.75	0.76	0.94
19	NSW	Sydney	0.06	1.97	1.97	-1.87	1.90	0.86
20	NSW	Mt Piper	-0.00	-1.32	0.00	-0.00	0.00	-0.00
21	NSW	Wellington	-0.13	1.64	1.64	-1.74	1.77	0.61
22	NSW	Wollongong	0.03	-0.63	0.00	0.03	-0.03	0.02
23	NSW	Shoalhaven						
24	NSW	Marulan	-0.12	-0.73	0.00	-0.12	0.12	-0.07
25	NSW	Yass	0.07	0.52	0.52	-0.45	0.45	0.26

	State	Demand Centre	%Δ Total Net Demand	%Δ Peak Demand	%Δ Peak Demand Ratchet	%Δ Utili-sation	%Δ Cost NSP	%Δ Total Cost
26	NSW	Canberra	-0.93	0.70	0.70	-1.62	1.64	-0.24
27	NSW	Tumut	0.28	1.42	1.42	-1.13	1.14	0.75
28	NSW	Tumut 3						
29	VIC	Dederang	0.02	1.04	1.04	-1.01	1.02	0.44
30	VIC	Loy Yang	-0.50	0.90	0.90	-1.38	1.40	0.09
31	VIC	Morwell	-0.49	0.87	0.87	-1.35	1.37	0.09
32	VIC	Yallourn	0.64	1.17	1.17	-0.52	0.52	0.86
33	VIC	Melb & Geelong	-0.02	0.93	0.93	-0.94	0.95	0.38
34	VIC	SW Vic.	-0.74	0.52	0.52	-1.25	1.26	-0.21
35	VIC	Reg. Vic.	-0.21	0.28	0.28	-0.49	0.49	-0.00
36	SA	South East	-0.04	1.95	1.95	-1.94	1.98	0.79
37	SA	Eastern Hills	0.14	1.20	1.20	-1.05	1.06	0.58
38	SA	Adelaide	-0.07	1.08	1.08	-1.13	1.15	0.41
39	SA	Riverland	0.04	1.59	1.59	-1.53	1.55	0.69
40	SA	Mid North	-0.08	1.30	1.30	-1.37	1.39	0.50
41	SA	Upper North	0.00	1.26	1.26	-1.24	1.26	0.53
42	SA	Eyre Pen	0.06	1.13	1.13	-1.06	1.07	0.50
43	TAS	George Town	-0.35	-0.22	0.00	-0.35	0.35	-0.20
44	TAS	Sheffield	-0.31	-0.54	0.00	-0.31	0.31	-0.18
45	TAS	Burnie	-0.26	-0.74	0.00	-0.26	0.26	-0.15
46	TAS	Farrell	0.14	0.02	0.02	0.12	-0.12	0.09
47	TAS	Hadspen	-0.33	-0.69	0.00	-0.33	0.33	-0.19
48	TAS	Palmerston	-0.24	-0.50	0.00	-0.24	0.24	-0.14
49	TAS	Waddamana	-0.25	-0.39	0.00	-0.25	0.25	-0.15
50	TAS	Liapootah	0.16	-0.02	0.00	0.15	-0.15	0.09
51	TAS	Tarraleah	-0.22	-0.24	0.00	-0.22	0.22	-0.13
52	TAS	Chapel Street	-0.26	-0.36	0.00	-0.26	0.26	-0.15
53	TAS	Gordon	-0.22	-0.10	0.00	-0.22	0.22	-0.13

5.3.3 Discussion

Table 5-3 and Table 5-4 show the general trend of TAS benefiting from global warming via the reduction in peak demand and total net demand but unable to gain the full benefit from these reductions because the network infrastructure is a sunk cost. In contrast QLD is suffering the effects of global warming from both per cent increase in total net demand and per cent increases in peak demand. Other than for Gladstone, all demand centres in Queensland experience lower per cent growth in total net demand than in per cent growth in peak demand, which adds to the total cost. Chapters 6 and 7 analyse the supply side to provide a fuller picture.

5.3.4 Conclusion

When compared to recent per cent increases in electricity prices, the prices increases in this section from direct pure climate change effects seem trivial. However, the section does clearly illustrate the underutilisation problem of the network infrastructure and the ratchet effect of peak demand in driving costs. The effect of adapting to climate change by using solar PV and other forms of non-scheduled SGU will greatly exacerbate the underutilisation problem, which warrants further research and is discussed in Section 6.5.1.

5.3.5 Further research

5.3.5.1 Effect of non-schedule generation on the utilisation of infrastructure

This chapter shows that first order climate change effect on demand causes an increase in the underutilisation of infrastructure using GCM projects from 200-10 to 2030-1. Exacerbating this underutilisation is the second order climate change effect or adaption to climate change by installing more non-scheduled SGU such as solar PV. Section 4 demonstrates that increasing non-scheduled generation causes underutilisation of network infrastructure using historical data from 2007 to 2011. The further research is to combine projection of non-scheduled SGU and GCM to find the effect on utilisation of infrastructure.

5.3.5.2 Combining population and global climate model projections

This chapter's demand projection is for a single GCM for the worst or hottest case and assumes the population stays at the 2009-10 level. Sensitivity analysis on the climate and population scenarios shown in Table 5-5 could be performed to address the following research questions.

Table 5-5 Sensitivity analysis of population and climate change futures

<table>
<tr><th colspan="2"></th><th colspan="3">ABS (2008) population projections</th></tr>
<tr><th colspan="2"></th><th>Series A
Higher growth</th><th>Series B
Most likely</th><th>Series C
Lower growth</th></tr>
<tr><td rowspan="3">CSIRO (2011) Climate Change Projections</td><td>Worst case (hottest)</td><td></td><td>2. Climate Sensitivity</td><td></td></tr>
<tr><td>Most likely</td><td>3. Population Sensitivity</td><td>1. Baseline</td><td>3. Population Sensitivity</td></tr>
<tr><td>Best case (coolest)</td><td></td><td>2. Climate Sensitivity</td><td></td></tr>
</table>

The baseline or non-adaption scenario

1. *What is the demand profile for continuing in a business as usual state?*

This question produces a baseline demand profiles for the 50 demand nodes on the NEM based on the population projection using the *most likely case* ABS (2008) Series B and on the climate projection using the *most likely case* GCM MRI-CGCM2.3.2 and SRES A1FI.

Sensitivity of the proposed baseline to climate change

2. *What is the sensitivity of economic impact to climate change?*

This question compares the sensitivity of demand to climate change where the proposed baseline based on the *most likely case* GCM is compared with the *worst case* GCM and with the best case GCM in Table 5-5.

Sensitivity of the project's baseline to population growth

3. *What is the sensitivity of economic impact to population growth?*

Sections 4.4 discusses the ABS (2008) population projection Series B as the most like scenario. In addition, Series A and C provide projections for relatively higher and lower population growth, respectively. This question compares the project's baseline that uses Series B against Series A and C in Table 5-5.

Relative impact of population growth and climate change

4. *What is the relative economic impact of climate change to population growth?*

Section 4.4 discusses climate and population as long-run drivers for demand in electricity. This question compares the relative economic impact of population growth to climate change. This project assumes no population growth to produce a pure climate change effect on demand, but what is the impact of a pure populates growth effect on the demand?

5.4 Discussion

Sections 5.1 to 5.3 present and discuss the results to the smaller research question presented in the introduction to this chapter. This smaller question is developed from the project's overarching research questions or four sources of maladaptation to climate change listed below:

1. institutional fragmentation, both economically and politically;
2. distorted transmission and distribution investment deferment mechanisms;
3. lacking mechanisms to develop a diversified energy portfolio; and
4. failure to model and to treat the NEM as a national node based entity rather than state based.

This section relates the finding from Sections 5.1 to 5.3 back to the overarching research question for the project. The discussion in this chapter will focus on NSPs and leave discussion of generation and retail to chapter 7 and 11, respectively. Retail and generation are amenable to a competitive environment but network service provision is a natural monopoly.

Section 5.1 identifies the dual problem of falling total demand but rising peak demand from 2007 to 2011. This is important as total demand affects the revenue base of NSPs but peak demand drives the legal requirement for NSPs to invest in more infrastructures to meet this demand. Further investment in infrastructure is fine provided utilisation of the infrastructure remains constant, as the cost of infrastructure per Watt will remain constant. However, total demand is falling, so the infrastructure cost per Watt will rise. The profit of the NSPs is determined by their capital expenditure, which provides them with the incentive to build more infrastructure. The DSM provides a solution to this dual problem but DSM is at odds with the NSPs profit motive, as DSM would reduce the need for NSPs to build more infrastructure. This situation relates to research question 2 'a distorted investment deferment mechanism'. A solution to this distorted investment mechanism is to change the basis for profit calculations for NSPs from capital expenditure to network utilisation to motivate DSM.

In addition, Section 5.1 identified a number of causes for the "apparent" fall in demand:

- non-schedule generation from SGUs such as solar PV and wind generators;
- energy efficiency; and
- solar hot water.

These three causes necessitated the introduction of the concept of gross demand and net demand. The AEMO produces figures of demand met by scheduled and semi-scheduled generation. This form of demand is really net demand. Grossing up the net demand by the three factors above explains that a good portion of apparent fall in demand is demand that still exists but is being met by alternatives to scheduled and semi-scheduled generation.

There are other factors that cause a real fall in demand that affects net demand such as:

- behaviour modification and education;
- weather and climate change;
- GFC ensuing a slowdown in economic activity; and
- the ongoing transformation of the Australian economy from industrial to service sectors.

The non-scheduled generation by solar PV is responsible for a large portion of the decrease in total net demand but is doing little to address the net peak demand that is driving further investment in infrastructure. This ignores the fact that non-scheduled generation has already addressed some gross peak demand but the AEMO's net demand figure focus attention on remaining net demand peaks. From an environmental perspective this decrease in demand is a success. However from the perspective of the NSPs, non-scheduled solar PV is disturbing the profitable dynamic of building more infrastructures to meet the peaks in demand, as the resulting decrease in total net demand has increased the cost of network provision per Watt. This situation has caused a political back lash against further investment in network infrastructure, which could be problematic for urgently required infrastructure. Additionally, the situation provides a strong disincentive for NSP to connect solar PV and other small-scale distributed generation. So, to ensure the ongoing deployment of solar PV and other distributed generation, there is a requirement to shift profit calculations for NSPs from capital expenditure to network utilisation. This shift would help address research question 3, regarding a diversified energy portfolio, and research question 2, regarding distorted investment deferment mechanisms.

One way in which NSPs can prevent the introduction of new distributed generation that may reduce utilisation of the network infrastructure, is to do nothing to improve the connection processes. These processes were developed in the days when only new large coal generators connected to the grid and connecting small generators seen inherently risky and troublesome. These processes helped deter the connection of small generators. The connection process is long and onerous, which was adequate for large projects with large budgets and time scales but unsuitable for the smaller distributed generation projects with much smaller budgets and shorter planning times. There is no incentive to improve the procedures as the distributed generation may cause further underutilisation of network infrastructure. There is an inherent conflict of interest between the profit motive of the NSPs and reducing greenhouse gas (GHG) emissions. This defence of profits by bureaucratic inertia is a maladaptation to climate change.

Behaviour modification and education have been responsible for some of the decrease in net demand. This can be attributed to two factors:

- raised awareness of electricity usage through education; and
- the higher price of electricity becoming consideration in its use.

There is a requirement to further focus people's attention on demand during peak periods. This can be achieved with TOU billing, which requires the installation of smart meters or equivalent. TOU billing to reduce peak demand is not in the interest of the profit motive of the NSPs, so provides the NSPs little incentive to install smart meters. A national rollout of smart meters and TOU billing is required to reinforce the gains already made in behaviour modification and education. However, the poorly handled rollout in Victoria has produced a national aversion to smart meters. This poorly handled rollout provides some valuable lesson on what to avoid:

- billing the customers for the full cost of the meter up front is unnecessary as the cost should be amortised over the life of the meter to prevent bill shock;
- the distributors focus was on savings on meter reading rather than providing the customer with extra value via in-house displays or gadgets to switch off appliances during critical peak or peak periods. These extra value items for customers are at odds with the profit motive of the distributor;
- the distributors being cost plus business are not necessarily the best organisations to deliver a project on budget, so tendering of the project is preferable; and
- additionally, the numerous small distribution companies on the NEM lack economies of scale to deliver a national rollout at the lowest price for consumers.

The Australian National Broadband Network (NBN) provides relevant lessons and similarities to a national smart meter rollout:

- the failure of the free market provider, Telstra, to deliver;
- the success of the Federal Government in handling the national telecommunication network both previously as Telstra and now as the NBN;
- a massive technological transformation of the entire telecommunications network from copper to fibre; and
- the massive economies of scale.

Looking internationally, Italy has successfully implemented a national rollout of smart meters. This was conducted by the national monopoly distribution company that was state controlled at the time. South Korea's monopoly transmission and distribution company is part way through a national smart grid transformation, which included smart meters. Both Italy's and South Korea's monopoly NSPs serve much larger populations, 60 million and 50 million, than the NEM with its 13 NSPs. The failure of the privately owned networks is further illustrate by Auckland CBD blackouts due to inadequate maintenance. Other privatised network failures, include the renationalisation of railways in Britain after the number of fatalities increased due to inadequate maintenance. Enron provides a further example of the failure of private sector NSPs. Chapter 9 expands on these issues.

Further to the proven inadequacies of privately owned networks, the privatisation of the NSPs by the states fails to address four issues:

- the fragmentation of a national monopoly lacking economy of scales;
- the poor investment deferment mechanism;
- boundaries between companies on the networks are weak spots for faults; and
- improved internal risk management through geographic spread.

The fragmentation of the NSPs as a natural monopoly has been recognised within NSW and Queensland in their moves to amalgamate their NSPs within their states. This logic can be carried through to the national scale to address research question 1.

Section 5.1 also identified two major deficiencies with wind generation and solar PV:

- intermittency; and
- the respective peak output from solar PV and wind being at noon and 3 pm are non-coincident with the peak in net demand.

Both these deficiencies can be addressed simultaneously with:

- time of supply payment; and
- energy storage: batteries, increased utilisation of pump-storage hydro.

Battery storage is currently too expensive for deployment in domestic situations but the rapid battery developments being driven by mobile phones and EVs are seeing costs of this technology drop considerably. The challenge is to put in place the right price signals and social structure for their deployment. One such factor is the need to introduce time of payment for the non-scheduled SGU such as solar PV and wind generator to provide the owners with the economic incentive to install energy storage. The economic incentive is the difference between peak and off-peak price of electricity. The technology is already in place to use TOS payment in some parts of the NEM. See Bell and Foster (2012) for further details.

The issue of TOU billing and TOS payment becomes more urgent when EVs become more wide spread. EVs have the potential to exacerbate the increasing peak as people recharge their cars after arriving home. However, with the right TOS and TOU price signals EVs could become part of the solution to address the growth in peak demand.

These DSM ideas are at odds with the profit motive of the NSPs who rely on the growth in peak demand to increase profits.

Section 5.1 has identified the problem of increasing peak demand and falling total demand induced in part by the adaption to climate change with the introduction of non-scheduled SGU. In contrast, Section 5.3 discusses how the direct effect of climate change will exacerbate this effect with a near ubiquitous increase in underutilisation of network infrastructure. Even the demand nodes with decreasing peak and total demand, mainly in Tasmania, have problems with increases in underutilisation. This results from the highest peak demand over the 2009-2030 determining the size of the network, as investment in network infrastructure is a sunk cost.

The poor deployment of DSM across the NEM caused in part by the lack of economy of scale and the coordination problems of the many small NSPs. In addition, these multiple NSPs create unnecessary costs for electricity consumers who are paying for multiple Chief Executive Officers (CEOs) and boards of directors. Mirroring the costliness of this economic fragmentation of a natural monopoly is the political fragmentation creating duplication of effort and unnecessary coordination problems. There is Federal level government administration of NEM, for instance the Australian Competition and Consumer Commission (ACCC), AEMO, AER and AEMC, and the five states of the NEM replicating these functions. In addition, there are coordinate bodies such as the Council of Australian Governments (CoAG) between the two levels. This political fragmentation makes DSM deployment more difficult to implement. In addition, these multiple administrative bodies provide unnecessary costs for tax payers.

One of the arguments for the high remuneration rates of CEOs in the private sector is the compensation for being in a competitive environment however the NSP are natural monopolies. This private sector premium seems unnecessary when running a natural monopoly. Additionally, there is the wider issue of social equity. Australia, by privatising the NSPs, is following the American neoliberal economic model. Following such a program, America has seen a sharp rise in income inequality over the last 30 years, a fall in the median male income and a concentration of wealth in the top one per cent of society (Gilson & Perot 2011; Jilani 2011; Liberto 2012; Norton & Ariely 2011). Chapter 10 expands on these issues.

Privatisation of the NSPs is suboptimal for Australia economically, environmentally and socially and will detract attention from the changes required to address climate change. The current profit motive of NSPs companies is at odds with the requirement to introduce of DSM.

5.5 Conclusion

This chapter has linked the findings from analysing electricity demand to the four factors contributing to the NEM's maladaptation to climate change:

1. institutional fragmentation, both economically and politically;
2. distorted transmission and distribution investment deferment mechanisms;
3. lacking mechanisms to develop a diversified energy portfolio; and
4. failure to model and to treat the NEM as a national node based entity rather than state based.

Projections of the effect of climate change on electricity demand have been developed. These half-hourly electricity demand projection for the financial years 2009 to 2030 for 50 demand centres across the NEM are now ready for use in Chapter 7 to study the effect of electricity demand changes on four factors:

- spot price;
- energy generated by type of generator;
- carbon emissions; and
- transmission line congestion.

The key finding from this chapter is the projected decrease in network infrastructure utilisation from two causes:

- climate change; and
- non-scheduled SGU.

However peak demand is still increasingly driving further investment in infrastructure. Demand side management can be used to address this issue. However there are three impediments to the deployment of DSM:

- the multiple NSPs on the NEM causing coordination problems and lack of economy of scale;
- the duplication of state and federal administration causing coordination problems; and
- the profit calculation of NSPs based on capital expenditure is at odds with DSM.

Suggested policy action:

- amalgamate all the NSPs into a single company:
    - massive economy of scale (already happening within NSW and QLD);
    - internal risk management through geographic spread;
    - reduce network weak spots by removing boundaries between companies;
- remove the states government's duplication of any federal administration;
- change the NSP's profit calculation from capital expenditure to network utilisation to encourage DSM;
- Federal Government retain a minimum 51% holding in the monopoly NSP; and
- Federal Government manages the technological transformation of the NEM similar to the copper to fibre transformation in the NBN.

6. THE IMPACT OF CLIMATE CHANGE ON GENERATION AND TRANSMISSION: REVIEW

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This chapter discusses the impact of climate change on electricity generation and transmission network. Stevens (2008, p. v) finds three key infrastructure areas within Australia that are most vulnerable to the effects of climate change, which are generation and transmission networks, low-lying coastal areas and drainage. Stevens (2008, p. 41) notes that the requirement for an efficient and reliable communication system between all areas of generation and transmission is an additional susceptibility to climate change. Introducing smart grid technologies makes this reliance on communication even more intense.

Chapter 2 discusses climate change projections of environment variables where this chapter discusses climate change implications for each type of generator and the transmission network and whether and how these changes are modelled in Chapter 4. Additionally, Chapter 9 discusses institutional structure and policy maladaptation in detail but this section does introduce a discussion of maladaptation when relevant.

This chapter discusses the impact of climate change on generation and transmission in the following subsections.

6.1 Transmission and distribution

Yates and Mendis (2009) provide a detailed analysis of the effect of climate change on the transmission and distribution networks in Australia. In summary they find that climate change will increase failure caused by an accelerated ageing of the infrastructure and an increase in extreme weather events such as floods, lightning strike and higher winds and temperatures. One mechanism for undermining the footings of poles and pylons is the increased duration of droughts and shorter but more intense periods of rain causing the ground to move. Another mechanism for corroding the infrastructure is the more widely dispersed sea spray discussed in Section 2.10. One further mechanism is the increase in severe bush fire weather increasing demand and stressing the grid, which increases the frequency of faults as discussed in Section 2.11.

Mitigating these factors requires both increases in preventative maintenance and redesign of transmission and distribution lines. Furthermore the increases in temperature reduce the thermal capacity of transmission and distribution.

Hence the case for deferred investment in transmission and distribution becomes stronger with climate change. So, Section 6.7 discusses the research questions on a renewable energy portfolio to deferred transmission investment and on portfolios that cause maladaptation by requiring further investment. Additionally, there are maladaptive institutional dynamics that favour heavy investment in intrastate transmission and distribution, which Garnaut (2011, p. 38) refers to as *"gold plating"* but he also discusses the lack of interconnectivity between states indicated by the disparity in wholesale electricity prices between states. In agreement, Stevens (2008, p. 39) identifies the need to improve interstate transmission as a means to better cope with regional demand, which is made more critical by climate change projections. Furthermore, Garnaut (2011, p. 2) states *"the recent electricity price increases have* *mainly been driven by increases in the cost of transmission and distribution. There is a prima facie case that weaknesses in the regulatory framework have led to overinvestment in networks and unnecessarily high prices for consumers"*.

However, Nunn (2011) disagrees with Garnaut's (2011, p. 38) assessment on gold plating intrastate transmission and under investing in interstate transmission. Nunn (2011) claims that Garnaut (2011, p. 38) has a *"pipeline congestion"* view where interconnectors are bottlenecks, so the implied solution is increase the capacity of the interconnectors. Nunn (2011) demonstrates using binding constraint data on the transmission network that bottlenecks occur well before the pipeline limit. So, any part of the network can affect flows on the interconnectors. Importantly, studying the frequency of the binding constraints shows that there lacks an obvious solution, as the binding constraints move around the network over time. In agreement, the AEMC (2008, p. viii) states that empirical research from the National Electricity Market Management Company (NEMMCO) shows that congestion tends to be transitory and influenced significantly by network outages. So, if bottlenecks in interstate transmissions are to be resolved, deeper integration of the interconnectors within the intrastate networks is required, which requires a whole of NEM focus rather than state focus.

This difference in focus on state rather than whole of NEM appears to reconcile the gap between Garnaut's (2011, p. 38) view on the institutional dynamics affecting interstate and intrastate transmission investment differently and Nunn's (2011) demonstration using binding constraint data. As part of the ongoing process to remedy newly identified problems on the transmission network, the AEMC (2008, p. vii) recommends that AEMO (2011d) provides information on congestion to enable participants to better manage risk. In addition the AEMO (2011d) provides information on proposed transmission investments to reduce congestion. However, the interactive map shows a single proposed upgrade to interstate transmission and the remainder of the proposed transmission developments are for intrastate, which is consistent with Garnaut's (2011, p. 38) gold plating claim. Furthermore, an AEMC (2008, p. iv) recommendation could account for some of this focus on intrastate development being to *"clarify and strengthen the Rules governing the rights of generators who fund transmission augmentations as a means of managing congestion risk, so that in the future connecting parties make a contribution to those funded investments from which they will benefit".* This rule leaves the interconnector used by many generators in an overtly complex situation, so favouring intrastate investment over interstate. The MCE recognises a need to address complex problems of this sort and have identified the need for a framework based on the interrelationship among the following five factors:

- the nature of network access;
- network charging;
- congestion;
- transmission planning; and
- connections.

These five factors are the subject of the AEMC's (2011a) transmission framework review. In an interim report, AEMC (2011b, p. i) states *"The arrangements for transmission in the [NEM] … still substantially reflect the jurisdictionally based arrangements that preceded the national market."* However the AEMC's role is as a rule maker within the existing market and political structures. So, Section 9.6 discusses three interrelated sources of maladaptation, the AEMC as rule maker within the existing institutional structure, the state focus versus whole of NEM focus and the complexity of the institutional structure as a source of fragmentation induced maladaptation.

Regarding transmission modelling, the Transmission Network Service Providers (TNSP 2009, p. 4) in the NEM use two methods to rate the thermal capacity of a line, normal and real-time. Understanding of these methods is important to modelling the effect of climate change on the thermal capacity of the line. Normal rating is a fixed value rating applied to normal systems operation. In comparison, real-time is a rating dependent on appropriate measurements of ambient temperature and wind conditions. TNSP currently use the normal rating method, which is a static rating based on a fixed time interval such as the season or month and independent of daily fluctuations in prevailing ambient conditions. The normal rating method is also referred to as continuous rating method.

The real time rating method can be calculated in five different ways but all calculations use data that is measured with acceptable frequently and accuracy. The first way to calculate real time rating is based on the ambient wind speed and temperature. The other four ways use one of the following parameters of the conductor: temperature, tension, sag or ground clearance. The TNSPs are in deliberation on switching from normal rating to real-time rating. The advantage in moving to real-time are increases in carrying capacity most of the time, which helps defer investment in new transmission line and helps ameliorate the effects of increases in ambient temperature due to climate change. The disadvantage is the data collection and coordination. Section 9.5 discusses using the date of switching from static to real time rating as a measure of the ability of the institutional structure of the NEM to adapt to climate change in an international comparison. The date of switching from static to real time is unknown but is an important consideration when modelling transmission. However, the switch to real time is likely to occur well before 2030, which is during the modelling period, so, a simplifying assumption is made that the static method is used for the whole modelling period.

The real-time rating method allows higher usage of the existing overhead transmission lines but the lines are still susceptible to accelerated aging and increases in faults caused by more frequent and severe lightening, wind, temperature, hail and bushfires and reduced carrying capacity due to global warming. Stevens (2008, p. 38) recommends burying cables as an adaption strategy. In addition, the increase in the incidence of bushfires requires an increased clearance of vegetation around the transmission lines, which adds further to the cost of overhead transmission. Stevens (2008, p. 39) notes that in Queensland there is a projected increase in bushfire risk, which poses an adaption problem for Queensland, as the region previously did not face serious fire risk. Stevens (2008, p. 39) notes that in NSW many distribution poles are wooden, which may require replacement with steel poles but the steel poles are susceptible to bushfires, again burying is an option. North eastern Queensland also has many aged wooden poles for distribution, which are particularly vulnerable to tropical cyclones as are the transmission lines. However the Department of Resources, Energy and Tourism (DRET) (2011a, p. 21) estimates that the cost of buried lines is ten times the cost of overhead lines.

High temperature superconductor (HTS) transmission lines by being buried also avoid most of the problems associated with climate change and overhead transmission. Currently, there are only a few commercial HTS transmission lines. However, this project's scope is to 2030 and given the rapid advances in HTS transmission, their inclusion provides a fuller analysis of potential adaption options (Banks 2009, p. iii). The Korean Industry and Technology Times (2011) reports that the Korean Electric Power Corporation (KEPCO) with LS Cable (2011) installed the world's longest HTS in a real transmission grid at 500m in length. The project is part of the Korean Ministry of Knowledge Economy's plan to develop smart grid technologies by 2016. HTS as opposed to low temperature superconductor (LTS) technology makes their use in transmission feasible, as HTS only require liquid nitrogen whereas LTS require liquid helium.

Minervini (2009) discusses further advantages of HTS over conventional transmission. The first advantage is that HTS have three times the current density, which reduces infrastructure and right of way costs, substation cost by delivering power at lower voltages and lower weight of HTS to allow less expensive deployment. Furthermore HTS DC carries only real power, has low radiated electromagnetic fields, and has no temperature excursions during normal operation and longer insulation life, and has much lower impedance when using phase angle regulators.

However Lacey (2011) comments that utilities are notoriously slow at adopting new technologies, which in part is a valid approach to reduce risk but in part could be that any transmission or distribution company investing in new technology takes on the risk and cost of research and development, while the other transmission and distribution companies can wait for the results and usually obtain a proven technology more cheaply and with little risk. The KEPCO superconductor example demonstrates the advantage for Research & Development (R&D) in a monopoly transmission and distribution company over the multiple ownership system in Australia. Section 4.6 discusses the slow smart meter deployment in the NEM, which further illustrates the effect of multiple-ownership on R&D. Section 9.6 compares the NEM's fragmentation inducing maladaptation with KEPCO's monopoly over transmission and distribution. Section 9.5 discusses the adoption of a smart grid road map, smart meters and superconductors as further climate change adaption performance indicators.

6.2 Coal

Regarding the supply of coal, Stevens (2008, p. 38) discusses how intense rainfall could cause flooding of the brown coal pits but relatively little adaption would be required to meet the increased flooding due to climate change. Additionally, Stevens (2008, p. 39) describes the risk in Victoria to coal generators from tsunamis and sea level rise as not significant. However in NSW there are more generators in low lying areas, which could become more susceptible to flooding. This NSW flood threat requires further study. The rail supply of coal in Queensland is already interrupted by severe weather events, which is likely to increase. Adaptation could include increasing storage facilities to increase reserves and upgrade the services (Stevens 2008, p. 39).

Regarding the operation of coal generators, NEMMCO (2008) identifies water scarcity as a factor that could affect generation capacity. In agreement, Stevens (2008, p. 24) finds that in Victoria droughts will reduce the supply of cooling water and affect the generation capacity This water shortage situation is exacerbated in Queensland with its rapid population growth and associated growth in electricity demand (Stevens 2008, p. 39). Plus higher temperatures will reduce the efficiency of the generation. But, Kogan Creek Power Station (CS Energy 2011a) uses water cooling technology that reduces water requirement by up to 90% over conventional methods, which demonstrates that water shortage is a surmountable problem for thermal generators. However, coal seam gas extraction presents further demands on water, which section 6.3 discusses.

Irving (2010) calculates surface relative humidity from absolute humidity where relative humidity is better for modelling human behaviour and specific humidity, readily derived from absolute humidity, is used to model gas and steam turbines, so this project uses relative and specific humidity.

The coal generators' solution to CO_2 emissions is carbon capture and storage (CCS). However AEMO (2011e, pp. 12-3) discusses how CSS technology is immature and estimate that the first full scale CSS installation will be operational between 2018 and 2021. In agreement, the Global CCS Institute (2011) confirms that there are no operational post combustion CCS systems and internationally there is only one actively being planned, which is by SaskPower in Estevan, Saskatchewan, Canada to retrofit a coal fired plant for operation in 2014. This situation contrasts sharply with the many renewable energy technologies already operating and maturing (AEMO 2011e, p. 14). Additionally, the Melbourne University Energy Research Institute (MUERI 2010, p. 4) claims that investment in technology sequencing such as CCS merely diverts funds and attention away from renewable energy generation. Furthermore, MUERI (2010, p. 50) claims that CCS projects are unable to capture 100% of fossil fuel emissions.

An additional adaption path open to coal generators is a hybrid solution. For example the Kogan Creek Solar Boost Project (CS Energy 2011b), which uses solar thermal energy to supply additional steam to the turbine to supplement the conventional coal-fired steam generation process. The project adds up to 44 MW during peak conditions to the coal generator's 750 MW baseload power output, so the project most probably only adds less than 1% to the overall output of the coal generator. However more importantly, this hybrid solution offers two mechanisms to reduce maladaptation. First is that the self-perception of staff at the coal generator changes from being one of coal generator staff to being energy providers, which reduces anxiety about losing their jobs to the renewable sector and aids acceptance of the new technology, as the demarcation between renewable and fossil fuel people becomes blurred, allowing for an easier transition. Second is that staff are trained in the use of the new technology, which provides a skilled workforce to deploy the technology. In addition, the hybrid solution uses existing transmission, which would help defer further transmission investment.

Officially opened in 2007, Kogan Creek is a relatively new generator, so both technologies, the new water cooling and the hybrid solar boost, may be unsuitable for retrofitting to the older generators or to those generators nearing the end of their life. Retrofitting these technologies needs considering on a case by case basis.

Section 9.2 discusses CPRS and the link between the rapid rise in electricity price and fossil fuels prices. Section 6.12 discusses using a portfolio of energy sources to moderate price fluctuations.

6.3 Gas

Stevens (2008, pp. 38-41) evaluates the susceptibility of the gas supply to climate change and finds the existing design practices would ensure robust function. However the switch from coal to gas generation in conjunction with an increased usage of air conditioners may test supply capabilities, which is an area worthy of further study. The development of the extraction of coal seam gas would improve the gas supply situation in the near future.

Brooks (1994, pp. 8-10) discusses environment variables affecting gas turbine performance where a one degree Celsius increase in temperature corresponds to a 0.6% decrease in design output. Similarly, an increase in specific humidity reduces the design output where an increase of 0.01 kg water vapour per kg dry air reduces output by 0.13%. Increases in either environment variable causes a linear percentage decrease in design output, which means more CO_2 per unit of energy generated. The relationship is fairly straight forward to model.
CCS for gas contrasts with coal CCS for two reasons. The ability to extract CO_2 from the exhaust gases emitted from burning coal is far more difficult than from burning gas, as coal emit more contaminates. In addition, gas can undergo a pre-combustion

removal of CO_2, which is a mature process. For example the Global CCS Institute (2011) shows that the pre-combustion Sleipner CO_2 injection project in the North Sea has been operational since 1996. However, as with coal, there are also no operational post combustion CCS systems for gas generators.

One climate change adaption path to reduce carbon emissions is to use gas generation as an intermediate step towards more renewable forms of generation in a double transition. However the Melbourne University Energy Research Institute (MUERI) (2010, p. 4) claims that a double transition merely diverts funds away from renewable energy and delays the reduction in CO_2 emissions.

This intermediate step toward renewable energy is difficult to ignore, as ABC (2011a) reported, the quantity of CSG in the Great Artesian Basin is quite extensive. The copyrighted interactive maps provide details of all the known CSG wells under development or appraisal and the regions covered by petroleum leases or applications. The petroleum leases and applications cover about one half of central and southern Queensland and about a quarter of NSW. There are 1,816 approved wells in Queensland in 2011 and this is estimated to grow to 4,014 wells by 2015 and to 40,000 wells by 2030. An important consideration is that CSG extraction requires large amounts of water. Currently, there is controversy over how much water CSG will use. For instance the National Water Commission (NWC) estimates that the Queensland CSG industry will use the equivalent to the water used by all Queensland households. The CSG industry estimate is one fifth of the NWC estimate. ABC (2011a) reports that the WaterGroup's (2013) estimate is between 2.5 times to five times the NWC's estimate. So, surrounded by controversy, CSG is a huge phenomenon with great potential for maladaptation and positive adaption if managed correctly. Adopting this intermediate step would place urgency on developing CCS at least for pre combustion, which implementing the CPRS will encourage. Sections 10.2 and 10.3 further discuss CPRS, CSG, maladaptation and the toxic chemicals used in the CSG extraction process. Section 6.6 discusses the CSG generator at Chinchilla in conjunction with solar power. Section 6.12 discusses gas generators role as a baseload replacement for coal or as peaking to complement renewable energy.

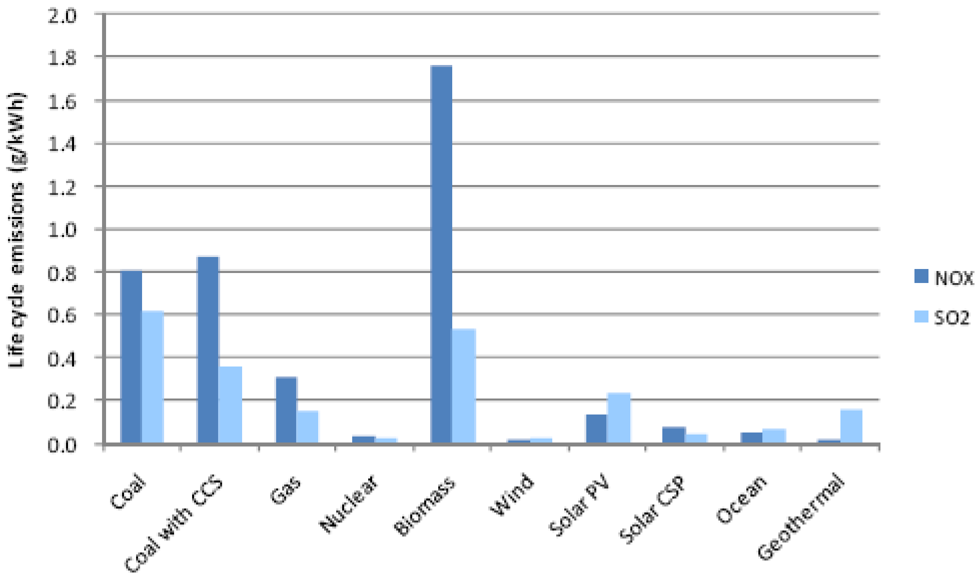
6.4 Diesel

Stevens (2008, p. 31) discusses the effect of climate change on the oil supply in North-eastern Queensland, where tropical cyclones are expected to interrupt offshore oil production and exports from ports. However, only minor investment was considered necessary to improve adaptive capacity.

6.5 Biomass and Biogas

Section 2.9 discusses the projected 2% to 5% decrease in rainfall due to climate change by 2030 for the NEM region less Tasmania and a small part of NSW. Given biomass' requirement for water, this reduces the potential for biomass. Additionally, biomass is one of the most contentious of all the renewable energy sources. Biomass' future as a renewable fuel relies on the carbon neutral claim. However, burning biomass releases particulate into the atmosphere (MUERI 2010, p. 32). In addition, Figure 6-1 compares the life-cycle emissions of SO_2 and of NO_X in grams per kilowatt-hour for different power-generating technologies. The NO_X emissions of biomass are over twice that of coal and the SO_2 emission of biomass are comparable to coal. These emissions do question whether biomass has a future role as a renewable energy source. However, there are numerous sources of biomass and these emissions would be better analysed on a case by case basis.

Figure 6-1 Life-cycle SO_2 and NO_x emissions of power-generating technologies



(Source: IEA 2011a, p. 22)

Additionally, there is also an ethical problem with some forms of biomass. For example, the recent episode of the US government subsiding corn for ethanol production increased the price of corn that is a staple diet for many poor people in Central America. This ethical dilemma of using food crops or arable land to produce biomass is an undesirable situation. So using crop or household waste as sources of biomass is more desirable from an ethical perspective. Furthermore, a positive aspect from using household waste as biomass is the reduction in landfill or as Bachelard and Gough (2011) quoted Bioenergy Australia's Dr Stephen Schuck *"[Australia is] a world leader in biogas, and many of our large landfills and sewage treatment works catch it and burn it to feed electricity into the grid"*.

In addition to ethical considerations, Stebbins (2011) reports on the farm price bubble in the Corn Belt created by the US government subsidies, which is proving politically difficult to manage, as rural communities become accustomed to higher wages and profits. This well intentioned US government policy has unintentionally created ethical conundrums grounded in a maladaptive political economic dynamic, which provides a warning for implementing infant industry legislation without sufficient exit strategy to prevent the legislation becoming a permanent fixture. There are many infant industries in the renewable energy sector requiring R&D and initial assistance for commercialisation. Section 6.12 discusses the benefit of developing a portfolio of energy sources, which requires sharply targeted infant industry assistance with exit strategies. For instance Section 9.1 discusses the maladaptive high feed-in tariff as blunt infant industry assistance tool with the requirement to move to a more sustainable and more sharply targeted form of assistance in conjunction with CPRS. Section 9.4 discuss the maladaptive consequences of RET and RET refinement to foster a portfolio of energy sources.

Furthermore, biomass has the practical limitation of photosynthesis, which is about 3% in most plants. In contrast solar PV efficiency ranges from 4.4% to 43.4% (NREL 2011). Furthermore, solar PV installed onto existing rooftops leaves arable land unchanged. However, MUREI (2010, p. 32) notes that there is research into using high yielding algae to produce biomass but this endeavour is not yet commercialised. More recently, the Queensland Premier (Bligh 2011b) announced Australia's first algae CO_2

absorption project at South Burnett power station, following successful trials at Townsville. While this avenue does address the ethical consideration of arable land use, the SO_2 and NO_X emissions require assessment.

An additional reason to avoid growing biomass for electricity is the reservation of biomass to produce substitutes for fossil fuels where the high power to weight ratio requirement precludes alternatives, for instance jet fuel. Bachelard and Gough (2011) discuss how Virgin Blue wants five per cent of its fuel to be sourced from bio-fuel by 2020. One source is eucalyptus mallee from Western Australia, which undergoes a process to extract the oil and other by-products. Eucalyptus has been used for 15 years in Western Australia to combat soil salinity and erosion problems, which provides utilisation and stabilisation of marginal land. Eucalyptus is harvested by cutting to ground level, which then re-grows from the rootstock. Currently, there are just 12,000 hectares growing but an estimated 2 million hectares would be required to fuel Australia's domestic air travel. However, using biomass for jet fuel is also contentious, as the Australian Broadcasting Corporation (ABC) (2008) reported on a Virgin test flight of bio-fuel being labelled a *"green-wash"*.

MUERI (2010, p. 10) suggests that biomass be restricted to crop waste, which is burnt during the lulls of solar thermal generation and is co-located with solar thermal plants to use the same electric generator. The biomass can be converted into pellets for easier storage and transportation.

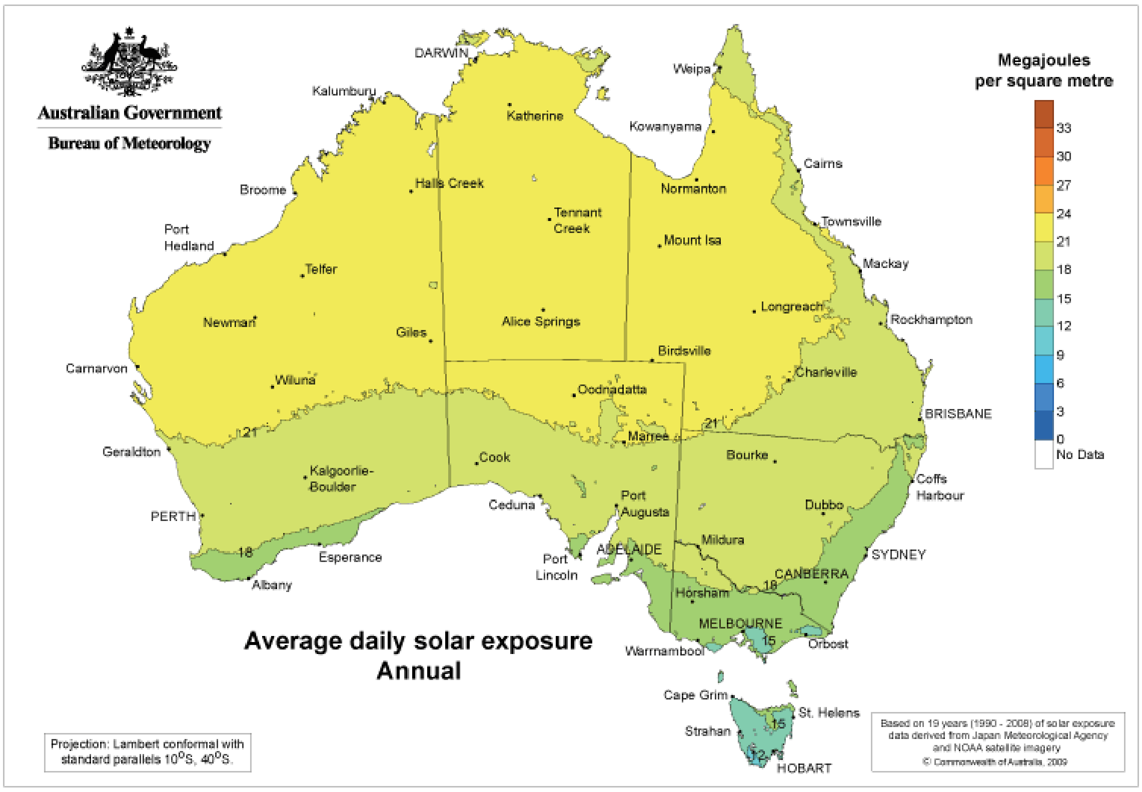
Renewable and other gases derived from waste such as the gasification of municipal, commercial, industrial and biomass waste and the anaerobic digestion of agriculture and farming waste, landfill and sewage gases can be injected into the gas grid rather than burning biomass at power stations. Renewable gases from both syngas (methanation) and biogas (upgraded) injected into the gas grid delivers much higher efficiencies (typically 80%) than electricity only generation (typically 20-35%) is growing in Europe, particularly in Germany, Scandinavia, UK, Netherlands and Austria.

6.6 Solar

Section 2.6 discusses the projected change in solar intensity from 1990 to 2030 and found in the most likely case there was no significant change across Australia, with a 1 to 2% increase in the 90th percentile across Australia but in the 10th percentile a 1 to 2 % decrease across Queensland and north eastern NSW and no significant change elsewhere in the NEM region. As mentioned in Section 2.6, in the 90th percentile case the simultaneous increase in solar intensity and temperature is countervailing but in the 10th percentile case the simultaneous increase in temperature and decrease in solar intensity would reduce solar PV electricity output.

However, in the most likely case from 1990 to 2030 there is no significant change in solar radiation across Australia. Figure 6-2 shows the current average daily solar exposure which provides a good approximation of the solar conditions to 2030. This is significant as adding some certainty to finding the best locations for solar generation, aiding adaption. This contrasts with wind speed where there are projections for significant changes in season variations across the NEM, which makes finding the best location more difficult. Section 6.7 further discusses the seasonal variations in wind speed.

Figure 6-2 Average daily solar exposure - Annual



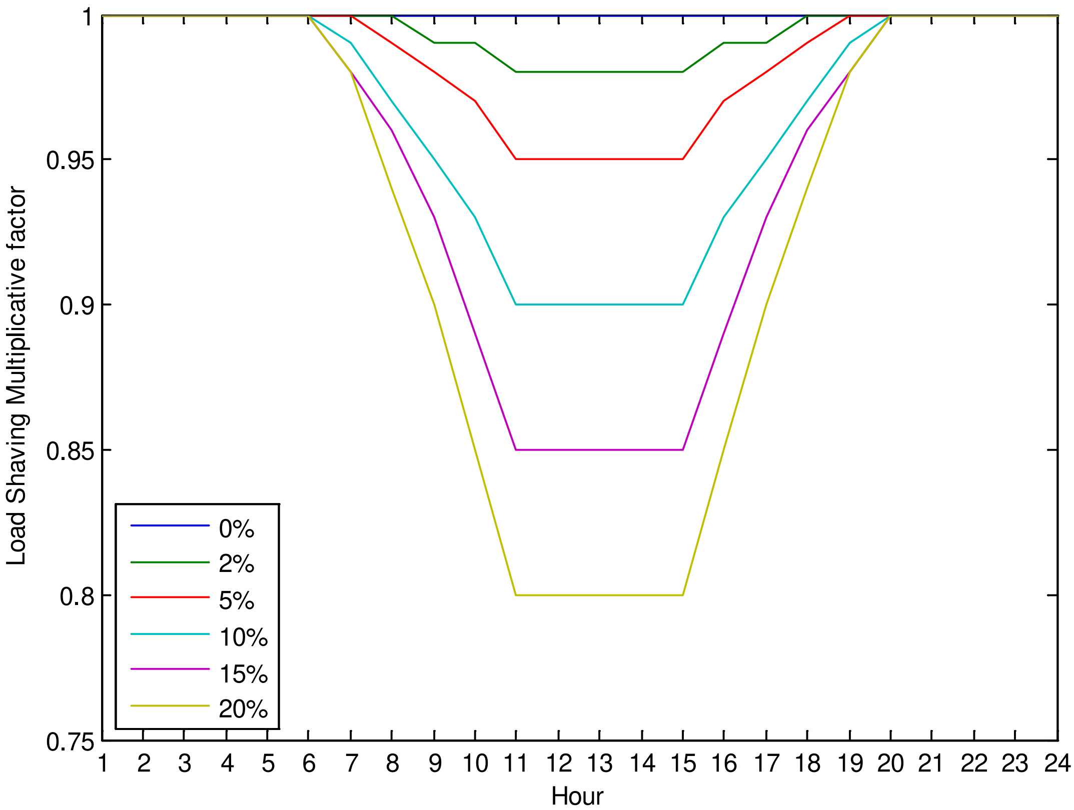
(Source: BoM 2011b)

Furthermore, the highest solar exposure contour is approximately coincident with the current highest temperature contours and with the highest projected change in temperature in Figure 2-4, which means the highest solar intensity areas are the hottest and projected to increase in temperature more than cooler areas. This observation has consequences for the type of solar generators. Solar PV becomes less efficient as the temperature increases whereas solar thermal is relatively immune. The highest solar intensity regions are the interior of Queensland and of Southern Australia. However both region are sparsely populated, which provides the advantage of cheaper land but the disadvantage of extra transmission costs. The remainder of the NEM region is well suited to solar generation other than Tasmania and southern Victoria. This ability to be widely distributed is an important adaptive advantage in transmission investment deferment. An often cited negative aspect to solar power is the daily cycle but this cycle is predictable and fits the demand profile of industry.

An additional negative aspect to solar is intermittency where cloudiness can suddenly reduce power output. However Tan (2011) discusses how the grid can accommodate solar energy without storage by responding to changes in real time to meet intermittency but concedes that the intermittency will become a problem as the penetration of solar PV or of solar thermal without storage increases. Section 6.7 discusses reducing the contract for reserve capacity in shorter time frames to meet greater intermittency. Section 6.8 discusses storage to meet intermittency. Section 6.12 discusses a portfolio of renewable energy sources to ameliorate intermittency.

Taking advantage of predictability of solar energy, Wild and Bell (2011 sec. 4.3.1) use a load shaving profile method to model PV penetration by shaving a percentage off the existing demand. This project extends the load shaving method to model solar thermal and wind generation. Figure 6-3 shows the summer version of the six load shaving profiles that are analysed in Wild and Bell (2011), which include 0%, 2%, 5%, 10%, 15% and 20%. The 0% profile is the business as usual scenario with regards to load shaving that is no PV. Figure 6-3 shows that the load shaving profiles are well suited to modelling solar based applications where load shaving commences early in the morning, gradually increasing over mid-morning and reaching a maximum around midday before tailoring off during mid-afternoon and completing dying out during late afternoon. The winter load shaving profile is a compressed version of the summer load shaving in both extent and duration. Figure 6-3 provides a highly stylised profile for a daily cycle, which this project extends by using the BoM's (2011c) real solar intensity data where the average of a number of representative weather stations in each demand region will form the profile for each day for the baseline year.

Figure 6-3 Summer load shaving profile



(Source:Wild & Bell 2011 sec. 4.3.1)

Table 6-1 shows the Australian Government (2011) legislated amended RETs where the years 2020 to 2030 inclusive are 41,000 GWh. This project assumes that the targets are met and investigates the effect on the NEM of differing portfolios of solar and of wind to meet the targets. This investigation endeavours to identify potential maladaptive effects from certain portfolios and to find if there is some optimal portfolio of wind and solar. Section 6.7 discusses wind generation and section 6.12 discusses wind and solar portfolios with respect to transmission investment deferment.

Table 6-1 Renewable energy target legislated by the Australian Government

Required GWh of renewable source electricity	
Year	**GWh**
2011	10400
2012	12300
2013	14200
2014	16100
2015	18000
2016	22600
2017	27200
2018	31800
2019	36400
2020	41000
2030	41000

(Source: Australian Government 2011, pp. 80-1)

Furthermore with respect to transmission deferment, the flexibility over the geographic deployment of solar generators comes in three ways, as roof top installation, as large-scale installations adjacent to the network within high demand regions or as a replacement or complement to existing fossil fuel generators with pre-existing transmission.

The Solar Flagships Program managed by the (DRET 2011b) provides two examples of large-scale solar power deployments that defer transmission costs. First, Moree Solar Farm in NSW is a PV installation that serves rural communities at the end of a transmission loop without generators. Second, a solar thermal installation, called Solar Dawn (2011), at Chinchilla in Queensland, which is co-located along the Roma to Tarong transmission line with the Condamine coal seam gas generator. Section 6.12 further discusses the adaptive path of gas with renewable power.

The Kogan Creek Solar Boost Project (CS Energy 2011b) provide an example of solar power using pre-existing transmission as a replacement or complement to the Kogan Creek generator. In addition to transmission investment deferment, there is the potential for solar thermal to replace coal fired boilers to reuse the steam turbine and electrical generators. Section 6.2 discusses the positive social aspects of this development.

Another case of fragmentation induced maladaptation is the optimal positioning of new large scale solar generators, which requires optimising across the legislation of five state governments and optimising across the best connection to the thirteen distribution companies and six transmission companies in the NEM. This fragmentation of infrastructure and superstructure is a reoccurring source of maladaptation. The Queensland Solar Atlas (Queensland Government 2013) and the Solar Bonus schemes in NSW (NSW Government 2013) provide examples of fragmentation induced maladaptation.

Robertson (2011b), the Queensland Minister of Energy, discusses the ‘Queensland Solar Atlas’ hosted by the Office of Clean Energy (2011), which is designed for energy businesses interested in investing in solar energy in Queensland. The Queensland solar map is a useful aid to business but indicative of the fragmented institutional structure in the NEM, which increases the difficulty of business trying to make the best investment decision across the whole of the NEM and duplicates effort across the five state governments and Federal Government. This fragmentation induced maladaptation produced an inferior investment environment at the cost of duplicating effort.

There are differing methods to calculate the tariff in each state for instance the Auditor-General of NSW (Achterstraat 2011) proposes a 'new solar bonus scheme'. This fragmentation induced maladaptation adds to the complexity of decision making and distorts the price signal for investors by using different method to calculate feed-in tariffs.

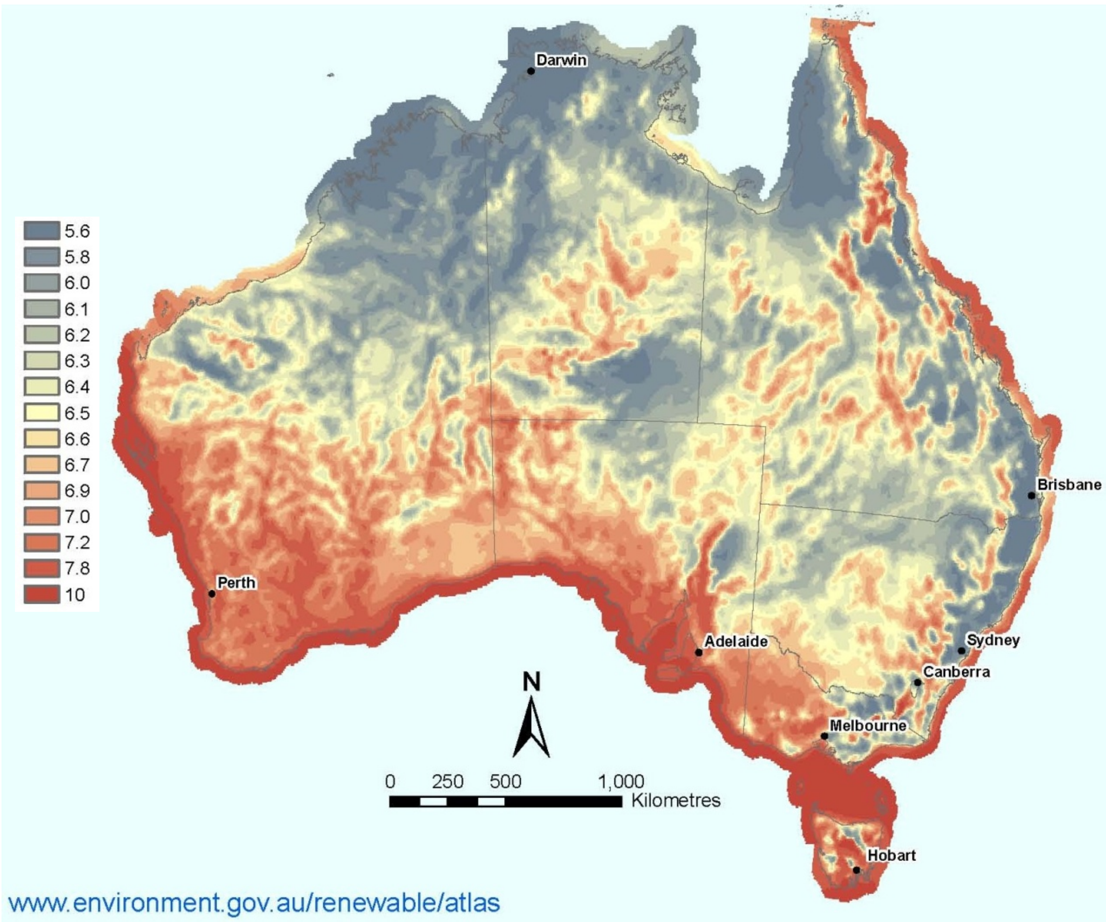
In a further source of maladaptation, the bonus or high feed-in tariff is a blunt policy instrument because the tariff combines two targets being carbon emissions reduction and infant industry assistance. But in 2012 the CPRS was introduced to specifically target carbon emissions. Regarding infant industry assistance, solar PV and onshore wind generation are no longer infant industries, so the high tariff only acts to reinforce their first mover advantage, which in effect blocks the development of alternative renewable infant industries. Chapter 9 further discusses feed-in tariffs, CPRS, RET and fragmentation induced maladaptation.

6.7 Wind

Section 2.7 discusses the projected change in wind speed from 1990 to 2030 and found in the most likely case there would be a 2 - 5% reduction in wind speed in a narrow band that travelled northward from Tasmania in summer to northern NSW in winter where the band dissipated in spring. In addition to this band of seasonal decrease, there is a corresponding band where wind speed increases by 2 - 5% across Queensland and Tasmania in winter. These climate change induced bands of wind speed swings of up to 10% are significant but the bands only affects regions for a season, so the average effect is insignificant, as can be seen in the annual wind speed map in Figure 2-5. Importantly, this band effect illustrates the need for interconnection between states to average out such variation in wind speed across the states confirming that onshore wind generation needs deeper integration of interstate transmission.

Most wind towers are 80 metres high. Figure 6-4 shows the wind speed at 80 metres above ground level in metres per second in 2008 where the more intense the red the higher the wind speed and the more intense the grey the lower the wind speed. Considering the climate change effects on wind are overall minimal if the states are well interconnected, Figure 6-4 provides an approximation to the wind speeds in 2030 to help find the best location for wind generators, which indicates that Tasmania, South Australia and Victoria are well endowed with wind energy close to the population centres. However the populated region between Sydney and South East Queensland (SEQ) has mild wind, which would require transmission investment to bring wind to these locations from further inland. This again confirms our earlier statement that onshore wind generation will require more intrastate transmission investment.

Figure 6-4 Mean wind speed in m/s at 80m above ground level



(Source: Department of Environment Water Heritage and the Arts 2008)

A further consideration in locating wind generators is their size. With diameters of up to 90 metres, placing wind farms in close proximity to population centres is unlikely for aesthetic, health, environmental, land cost and safety reasons. For instance The Economist (2010) reports on how the Bald Hills wind project, Victoria, in 2006 was rejected based on the danger posed to the rare Orange Bellied Parrot. Additionally, Rapley and Bakker (2010) review the literature on sound, noise, flicker and the human perception of wind farm activity, which suggests that a section of the population are adversely affected with sleep disturbance, headaches, dizziness, anxiety and depression but some experts claim that the noise levels are virtually undetectable and so low that sound cannot directly cause these symptoms. Onshore wind farm deployment is a contentious issue. As can be seen in Figure 6-4, Australia does have the option of offshore wind generation being adjacent to the highly populated coastal areas and large sparsely populated inland areas.

The transmission deferring ability of solar and wind contrasts sharply, as Figure 6-2 shows solar generators can be distributed around most of the NEM region to defer transmission costs whereas wind generation requires further interstate and intrastate transmission investment to smooth out variation and to take the power from remote locations to the grid, respectively. This comes with the caveat that onshore wind generation is transmission investment deferring to a point because the windy locations adjacent to existing transmission infrastructure are initially used to meet local demand. After which more transmission infrastructure is required to export the excess supply and more remote locations for wind farms are established, requiring new infrastructure. Simulations and current developments are consistent with the requirement of wind generations for more transmission, after an initial transmission investment deferment phase.

For instance Zhao (2011) uses simulations to investigate the effectiveness of wind generators or PV in transmission deferment within Queensland and finds after the initial addition of wind generation there is deferment but subsequent addition of wind generation requires more transmission. This dynamic is a consequence of the large disparity in wind distribution in Queensland where the windiest places are on the northern edge of the grid. This project extends Zhao's (2011) simulation regionally from just Queensland to the whole of the NEM and from just simulating either solar or wind penetration to different portfolios of solar and wind to meet the RET as discussed in section 6.6 and shown in Table 6-1.

Consistent with Zhao's (2011) simulation of early deferment are the existing South Australian wind farms at Cathedral Rocks, Mt. Millar, Snowtown, Mintaro, Wattle Point, Starfish Hill, North Brown Hill, Hallett Wind Farm, and Hallett Hill, which were placed close to pre-existing transmission and population centres.

Regarding new transmission, Windlab (2003) specialises in prospecting for sites most suitable for wind farms. Four sites selected for development are:

- Kennedy located 290km south-west of Townsville, Queensland
- Oakland Hill located 5km south of Glenthompson, Victoria
- Coopers Gap located 65km north of Kingaroy, Queensland
- Collgar located 25km south east of Merredin, Western Australia

Kennedy provides an example of a proposed wind farm cluster built in a remote location and requiring new transmission (Leighton Contractors 2010). The new transmission line will be connected to the grid southwest of Townsville. This connection point near the edge of the NEM may require further transmission investment to take the extra supply from a wind farm expansion in Kennedy. A positive aspect to this development is how private enterprise has invested in transmission from the edge of the NEM to a remote location that is suitable for a cluster of wind farms. However, there is the problem of having extra supply on the edge of the grid away from the main demand centres, with the potential for further supply expansion and with the subsequent required upgrading of adjoining transmission. This multiple ownership of a network structure where the action of one owner affects the dynamics of the network is a pricing challenge, which is particularly relevant to wind generation and the significant transformation of the network required to absorb the variability and patchy geographic spread of the resource wind.

These findings support Garnaut's (2011, p. 2) claim that *"there can be large gains from planning transmission for a truly national electricity market, with greater inter-state connectivity increasing competition, resilience against supply shocks, and reducing the cost of connecting new low-emissions power sources."* Section 9.6 further discusses the issue of transmission ownership in a truly national electricity market.

Furthermore, AEMC (2009, p. vi) recognises the need to develop a new mechanism to deal with the ownership of and payment for building new transmission into new regions of high wind suitable for clusters of wind farms. Campbell, Banister and Wallace (2011) agree calling for new ideas to address this issue.

However, Banister and Wallace (2011, pp. 15-6) suggest the advantage of exporting wind energy between regions may be overrated. Table 6-2 shows that there appears to be little correlation of regional wind generation output with regional demands but there does appear to be quite significant correlations between wind farms. However Figure 2-5 shows that climate change is expected to alter wind patterns, which will reduce the correlation between states and increase the coincidence of simultaneous electricity surpluses and deficits between states.

Table 6-2 Correlation of wind and demand

		Demand					Wind			
		NSW	**QLD**	**SA**	**TAS**	**VIC**	**NSW**	**SA**	**TAS**	**VIC**
Demand	**NSW**	1								
	QLD	0.83	1							
	SA	0.81	0.67	1						
	TAS	0.72	0.54	0.58	1					
	VIC	0.89	0.75	0.85	0.78	1				
Wind	**NSW**	0.08	0.11	0.05	0.1	0.07	1			
	SA	-0.16	-0.08	-0.07	-0.15	-0.16	0.34	1		
	TAS	-0.06	0.04	-0.06	-0.04	-0.04	0.31	0.24	1	
	VIC	-0.08	-0.05	-0.06	0	-0.05	0.44	0.64	0.47	1

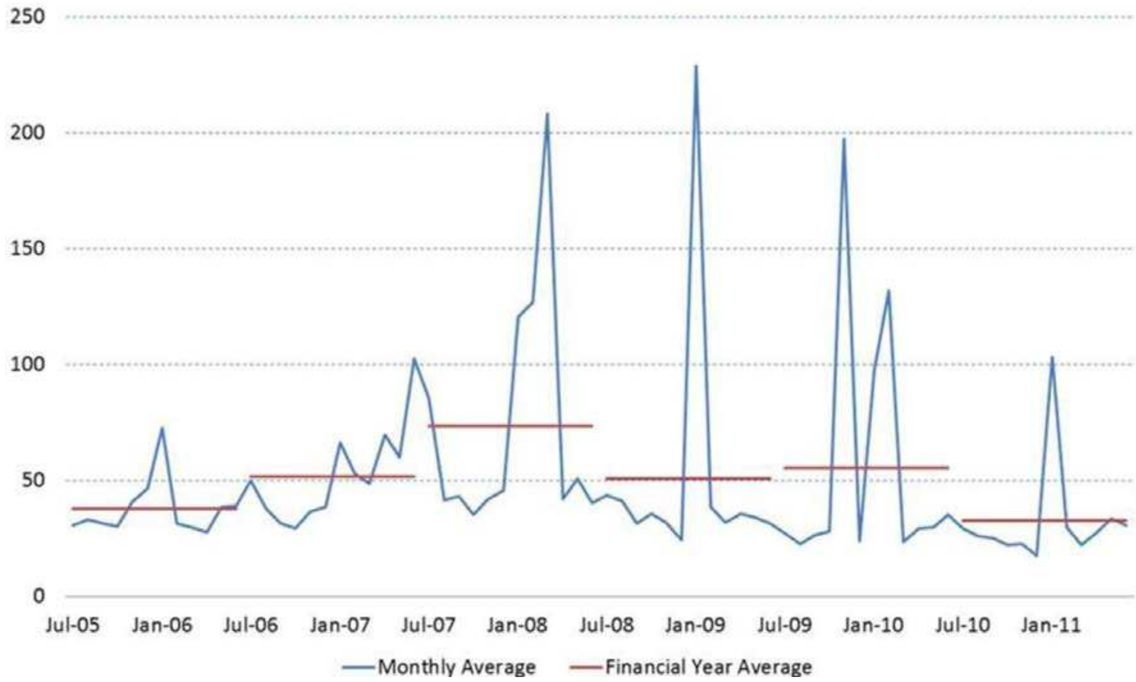
(Source: Bannister & Wallace 2011, p. 15)

Foster et al (2011, p. 3) states that the evolution of efficient storage systems will be critical in solving transient stability problems associated with wind generation. Alternatively, AEMC (2009, p. viii) discuss a solution proposed by the reliability panel in accordance with the national electricity law, which is an increased capacity for AEMO to contract for reserve capacity in shorter time frames than has been possible to date, where Open Cycle Gas Turbine (OCGT) and hydro could meet the transient stability problem in a peaking role. Section 6.12 discusses the role of gas in this peaking role as OCGT rather than as a baseload replacement for coal and Section 6.8 further discusses storage.

Additionally, technological innovation in the electronics of wind turbines can help combat adverse stability conditions. For instance the Finnish Technical Research Centre or *Valtion Teknillinen Tutkimuskeskus* (VTT 2009, pp. 30-4) discusses how recent innovations in the electronics of wind turbines themselves. Combined with transmission technologies incorporating flexible AC transmission systems (FACTS) such as static var compensators (SVC) can combat adverse stability consequences by providing fault ride through and by suppling ramping capability for frequency control and reactive power for voltage stability. However VTT (2009, pp. 30-4) notes that modification of legislation or codes in many countries is required to make use of the technology.

Furthermore, Parkinson (2011b) argues that the transient stability problem of wind farms may be overstated where in South Australia, which has Australia's largest penetration of wind, the requirement for OCGT or peaking gas has actually fallen, as has the spot price for electricity. The AMEC chairman (Pierce 2011) confirms this reduction in the average sport price for electricity in SA, see Figure 6-5.

Figure 6-5 Average Sport Price in South Australia per MWh



(Source: Pierce 2011, p. 7)

However the AMEC chairman also discusses the increase in volatility in spot price in Table 6-3 where there have been increases in half-hours with negative spot prices and increases in half-hours with spot prices above $5,000 and $300 per MWh. The increase in negative spot prices and the reduction in 2010 of high sport prices are consistent with Parkinson's (2011b) claim that the demand for OCGT has fallen.

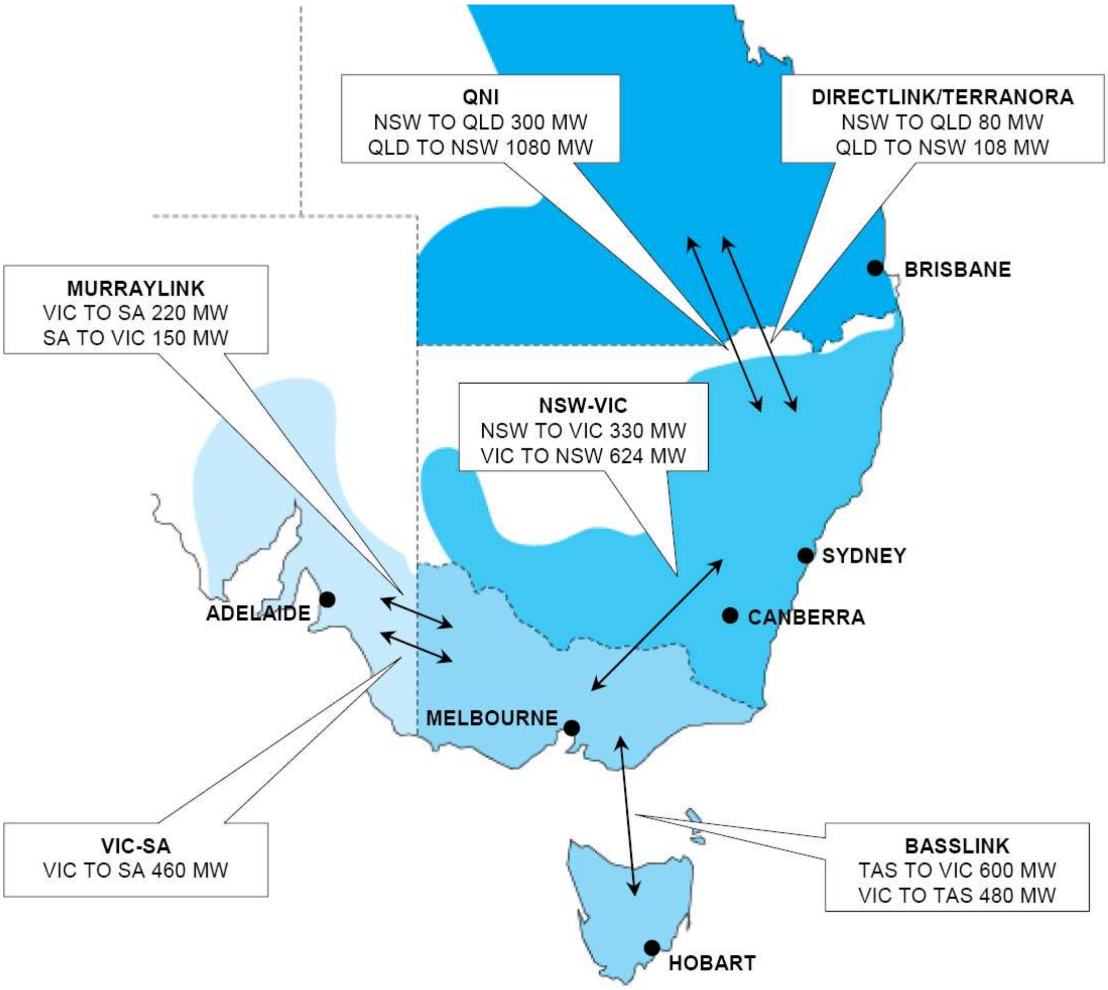
Table 6-3 South Australian wholesale prices

Year	Number of half-hour prices in South Australia			
	Above $5,000/MWh	Above $300/MWh	Below $0/MWh	Below -$300/MWh
2006	1	62	1	0
2007	3	78	10	2
2008	52	78	51	3
2009	50	97	93	8
2010	24	58	139	18

(Source: Pierce 2011, p. 8)

Parkinson (2011b) claims that there are successful large installations in a number of countries where variability has not posed a major problem. For instance Jones (2011, p. 91) discusses the East German company 50Hertz that has 37% of electricity supplied by wind generation. However, 50Hertz can sell and send surplus electricity to Poland, Czech Republic, Austria, Denmark or the former West Germany, which would reduce the likelihood of negative prices. In contrast Figure 6-6 shows that SA can only send its surplus electricity to Victoria. Additionally, examination of the interconnectors shows a 150 MW thermal capacity from SA to VIC but a 680 MW thermal capacity from VIC to SA. This large VIC to SA thermal capacity is a legacy of the cheap electricity generation in Victoria using brown coal. Exacerbating the situation, Parkinson (2011b) notes that there are legislative moves in Victoria to block interconnector expansion from SA to VIC, which is a source of maladaptation to climate change.

Figure 6-6 Interconnectors on the NEM

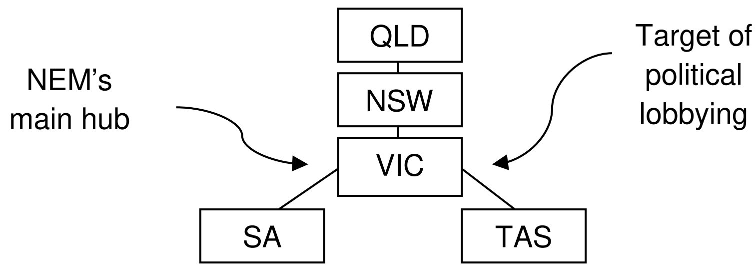


(Source: Tamblyn 2008, p. 7)

Additionally, Parkinson (2011b) notes legislative moves in Victoria to hinder the installation of new wind generation, which is a further source of maladaptation. Together the legislation blocking the interconnector expansion and hindering further wind generation installations will promote the continued use of brown coal in Victoria's state own power stations, which produces the highest CO_2 emissions per unit of electricity of any other fuel.

Figure 6-7 shows that the politically lobbying and conflict of interest is targeted at the main hub in the NEM. By targeting the main hub in the NEM, the role for wind generation is especially undermined and generation from renewable sources generally.

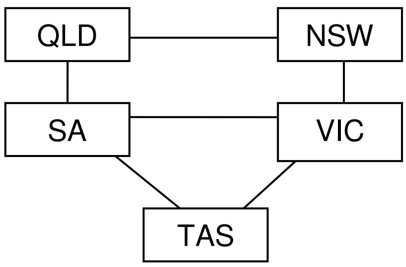
Figure 6-7 NEM's main hub targeted by political lobbying and conflict of interest



However, NEMLink provides a solution to the maladaptation in Victoria exacerbated by Victoria's position as the main hub in the NEM. Figure 6-8 shows the topology of NEMLink. Garnaut (2011, p. 32) discusses NEMLink (AEMO 2010b) as providing a truly national grid by adding interconnectors between SA and QLD and between SA and TAS. The current grid topology in

Figure 6-7 lacks redundancy where breaking the interconnectors between two states isolates parts of the grid. In comparison, the NEMLink topology in Figure 6-8 can lose the interconnectors between any two states and the grid stays connected. This redundancy provides technical advantages (AEMO 2011f) but also provides redundancy against political maladaptation. Section 9.6 further discusses the conflict of interest of state involvement in interconnector management.

Figure 6-8 NEM's topology under NEMLink



NEMLink was not justifiable in the short term but came close to break even in a strong carbon price scenario in 2021. NEMLink is currently under review (AEMO 2011f). Section 4.2 further discusses NEMLink in a research question. Furthermore, the SA-TAS interconnector of NEMLink provides the opportunity to develop pumped hydro storage in Tasmania from the excess electricity from onshore wind generators in SA. Section 6.8 further discusses pumped hydro storage.

In a research question, Section 4.2.3 discusses simulations of different solar and wind portfolios to meet the RET to test the NEM's ability to cope with the projected increases in variability of wind by 2030. A complimentary research question discusses relaxing the constraints on interstate transmission to test Garnaut's (2011, p. 2) claim regarding inadequate interconnectors and to test the integration of further onshore wind generation into the NEM.

6.8 Storage

Energy storage offers the benefit of 'time shifting' that is allowing electricity to be produced for consumption at a later time. Time shifting has at least two major bulk applications. Firstly, generators have the ability to store energy off peak for release onto the grid during peak time, which provides investment deferment for generation. Secondly, storage located adjacent to net demand regions on the grid stores energy during off peak to meet peak demand, which provides investment deferment potential for both transmission and generation.

The Energy Power Research Institute (EPRI) (2010, p. ix) claims that over 99% of storage capacity worldwide is pumped hydro. EPRI (2010, Figure 2-2) shows the positioning of energy storage types where pumped hydro provides bulk power management to occupy the highest system power rating and longest discharge time combination and compressed air energy storage (CAES) the next largest bulk power management system. Other forms of storage find alternative roles such as Li-ion batteries in frequency regulation. EPRI (2010, pp. 4-22) compares the cost of various bulk energy storage options to support systems and large renewable integration and finds CAES is currently about half the price of pumped hydro. EPRI (2010, pp. 5-2) expects Li-ion batteries to reduce dramatically in price after mass production to meet the demand in the automotive industry. CAES and in future Li-ion batteries will provide renewable energy generators with suitable technology to smooth out power output fluctuations and defer investment in transmission and generation.

While pump hydro is a mature technology and well established on the NEM, the legal and technical aspects of time shifting for other storage technologies is the subject of further research. Section 9.5 further discusses grid linked storage that this project uses as an adaption to climate change performance indicator.

There are other energy storage mechanisms to add to the list of electricity storage systems that use different energy mediums to store energy and overcome the intermittency of renewable electricity generation such as thermal storage and 'power to gas' technologies. Not using electricity for heating and cooling but using the waste heat of local electricity generation and/or renewable heat sources where the heat or thermal energy can be easily stored and utilised significantly reduces the need for expensive electricity storage. EPRI (2010, Figure 2-2) fails to present power-to-gas as an energy storage option. Section 6.10 discusses the transmission and generator investment deferring ability of power-to-gas. The next section discusses pumped hydro storage in more detail.

6.9 Hydro

Section 2.9 discusses the projected 2% to 5% decrease in rainfall due to climate change by 2030 for the NEM region less Tasmania and a small part of NSW. In addition, rainfall in far north Queensland is projected to be unaffected. Consistent with the projected decreases in rainfall for the majority of the NEM region, Stevens (2008, p. 24) finds that hydro capacity will be adversely affected. However, the projected rainfall in Tasmania and far north Queensland is unaffected, which bodes well for the substantial hydro facilities in Tasmania. In far north Queensland, Stevens (2008, p. 40) suggests that hydro could be considered as a distributed energy source to ameliorate the combined effect of the remoteness on the NEM and of the projected increases in storms that could increases the frequency of power failure due to loss of transmission or distribution. In contrast, MUREI (2010, p. 33) sees no role in expanding hydro and MUREI (2010, p. 23) suggests the role of backup for existing hydro to meet peak demand with an expansion in pumped hydro to increase storage. Tasmania is the most likely candidate for the introduction of pumped hydro for three reasons. First is the existing extensive hydro development. Second is the projection for no appreciable change in rainfall in 2030 discussed in Section 2.9. Third is a projected increase in wind speed for most of Tasmania other than a slight decrease in summer in northeast Tasmania, as discussed in Section 2.7. These three factors make the combination of expanding onshore wind generation and of introducing pumped hydro storage very attractive for the export of electricity from Tasmania. Section 4.2 proposes a simulation of an expansion of onshore wind generation and introducing pumped hydro storage in Tasmania.

6.10 Geothermal, wave, off-shore wind, power-to-gas and other options

At the time of writing, the previous sections complete a discussion of all the renewable energy generation technologies with at least one planned commercial installation in Australia. There are many other forms of renewable energy at varying stages of development around the world. Bachelard and Gough (2011) describe a key problems with comparing large-scale renewable energy is a "beauty parade" of dozens of different options where the costs and reliability are relatively untested and are therefore argued vigorously. So, rather than trying to pick winning technologies, an alternative approach is developing a framework to treat each technology on an equal footing that is to acknowledge the requirement for infant industry assistance until the first commercialised operation when equal access to the grid and remuneration at the locational marginal price is provided and where the CPRS acts as the mechanism to address CO_2 emissions, as suggested by Garnaut (2008). Noting even the coal generators received assistance from the states in an infant industry stage. Chapter 9 discusses maladaptation and institutional structures impeding the development of a suitable environment to assist a wider range of renewable energy technologies through their infant industry stage to achieve a broader portfolio of energy sources. Section 6.12 discusses the benefits of a broader portfolio of energy sources.

The following technologies developing outside Australia are too attractive to remain undiscussed:

- off-shore wind and wave power;
- solar thermal heating and cooling and power-to-gas.

Serious consideration needs to be given to their implementation in Australia. Power-to-gas is discussed last as it overcomes intermittency and matching supply to demand problems of renewable energy.

6.10.1 Off-shore wind and wave power

Although Australia's onshore wind energy capacity may be a bit patchy in the NEM, Australia has the second largest offshore wind energy resource in the world, second only to the Russian Federation (Makridis 2012). Australia also has considerable wave energy resources. For example, wave energy capacity from Geraldton to Tasmania alone is over 1,300TWh/year, about five times Australia's total energy requirements (CSIRO 2012a). Offshore wind and marine energy resources are generally within 20km of the coast and most energy demands in Australia and would provide greater capacity factors to the electricity infrastructure with the development of an offshore grid similar to the UK.

6.10.2 Solar thermal heating and cooling and power-to-gas

'Power to gas' technologies where surplus renewable electricity from wind and solar is converted into hydrogen or syngas for injection into the gas grid overcomes the issues associated with electricity storage as gas can be easily stored, transported and utilised removing the link between generation and demand. 'Power to gas' project being developed in Germany (E.ON 2012) provides a robust alternative to switching off wind turbines or solar at times when generation exceeds demand. This will become an increasing issue with high penetration of intermittent wind and solar. Additionally the CSIRO (2010b) solar gas project at Newcastle provides a technique using solar power to increase the energy content of gas.

Onshore wind will benefit from power-to-gas technologies to overcome the necessity of switching wind turbines off at times of too much electricity generation. This is a problem that has had to be overcome in Europe due to Europe's high degree of wind energy penetration.

In Germany, it has been found that up to 15% hydrogen gas converted from surplus renewable electricity can be injected into the natural gas grid network at 70% efficiency and above 15% penetration hydrogen can be converted into syngas and then a substitute natural gas via 'methanation' injected into the gas grid at 56% efficiency for surplus renewable electricity that would otherwise be lost. This compares with the 33% efficiency of a typical coal fired power station before grid losses.

The electricity infrastructure needs to be viewed in conjunction with other energy infrastructure such as thermal energy and gas infrastructure. In Europe, particularly in Scandinavia and Germany smart grids are not considered for the electricity grid alone but in conjunction with the thermal energy and gas grids and different forms of energy are switched between grids to provide energy storage and manage over or under generation and peak loads and to mitigate or adapt to the effects of climate change. Section 9.5 discusses further smart grids.

Using thermal energy derived from solar thermal heating and cooling and power-to-gas technologies will also reduce electricity consumption and peak demand impact on the electricity infrastructure as well as overcome the intermittency of renewable electricity generation utilising thermal storage or storage of renewable gas in the gas infrastructure. These techniques have been developed and implemented in Europe, particularly in Germany and Scandinavia increasing the capacity and avoiding costly investment in the electricity infrastructure.

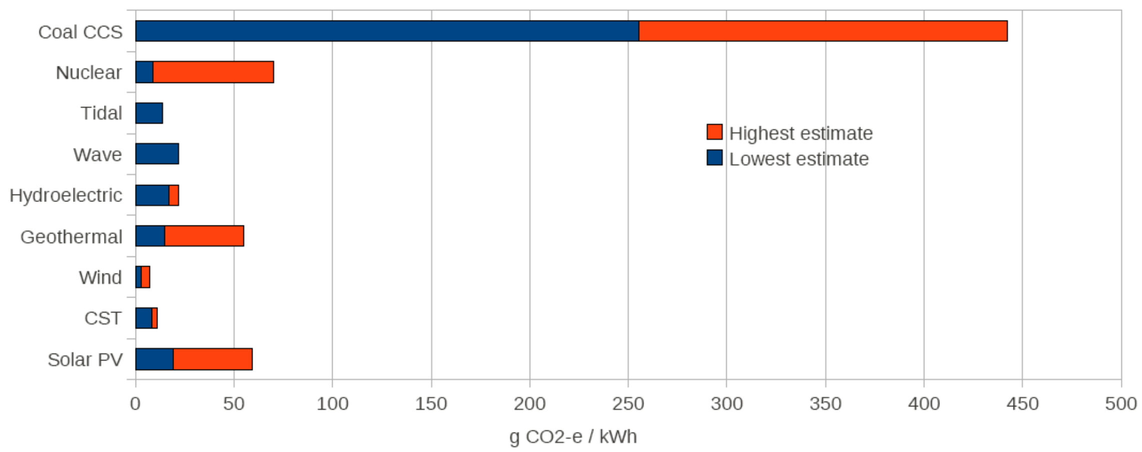
It should also be noted that in Germany and Sweden renewable gas can only be used for decentralised energy (cogeneration/trigeneration), renewable heating and cooling or transport. It cannot be used for electricity generation only power stations by law. Other countries such as Austria, Netherlands and the UK use other incentives such as banded feed-in tariffs.

In the UK, a single company runs both the electricity transmission and gas grids removing vested interest barriers between the two grid infrastructures.

6.11 Lifecycle carbon footprint of generating technologies and transmission

Figure 6-9 shows the expected CO_2 emissions per kilowatt hour averaged over the life cycle of the generating technology. Figure 6-9 could be extended to include OCGT and Combined Cycle Gas Turbine (CCGT) in combination with and without CCS. Gas generators provide a potential intermediate step to a more balance portfolio of renewable energy. Furthermore, if the lifecycle CO_2 emissions of transmission and distribution is add to all the generator types other than rooftop installed solar PV, this would help reduce the CO_2 emissions gap between solar PV and the other forms of renewable energy.

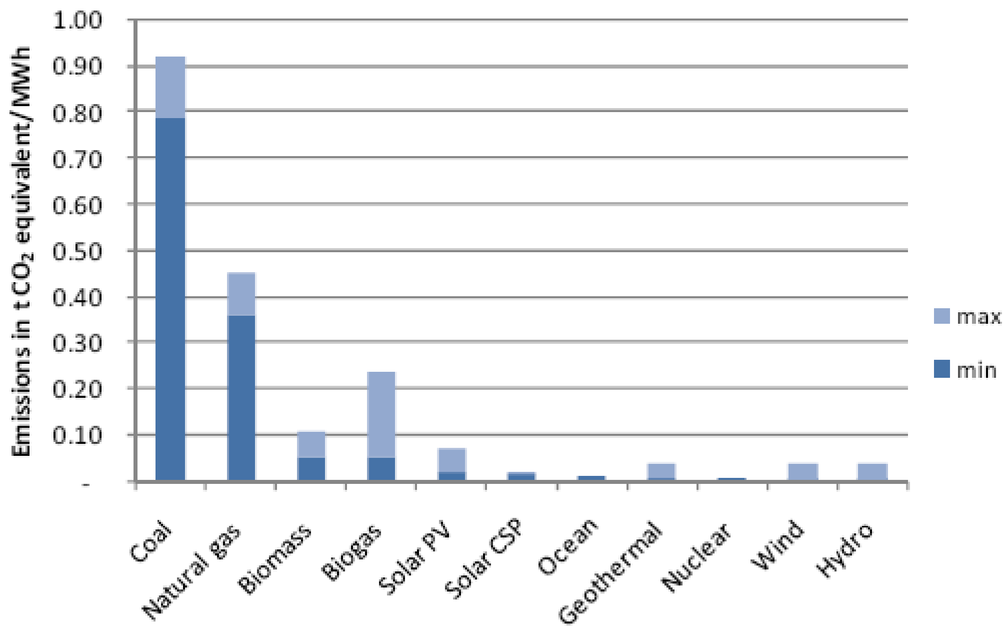
Figure 6-9 MUREI's life-cycle CO_2 emissions of power generating technologies



(Source: MUERI 2010, p. 35)

Like Figure 6-9, Figure 6-10 compares the life-cycle CO_2 emissions of power generating technologies but includes natural gas, biomass and biogas.

Figure 6-10 IEA's life-cycle CO_2 emission of power-generating technologies



(Source: IEA 2011a, p. 18)

Figure 6-10 shows that natural gas offers half the CO_2 per unit of power than coal, so using gas in an intermediate step does provide an avenue to reduce CO_2. This ratio of coal to gas emissions per unit of power would be amplified under CPRS when the older more CO_2 emissions intensive coal generators close and are replaced by more efficient gas generators. Furthermore, biomass and biogas do offer substantial reductions in CO_2 emissions but there are additional ethical and emission problems that Section 6.5 discusses. But rather than selecting the source of energy with the lowest CO_2 emissions, there are advantages to a portfolio of energy. In addition, as the technologies mature, the relative ranking of lifecycle CO_2 emissions will alter and only with hindsight can one select the lowest lifecycle emissions technology, so prematurely selecting a technology and terminating the evolutionary path of other technologies is unadvisable.

6.12 Portfolio of energy sources and baseload as a source of maladaptation

Building bigger and longer grids with greater exposure to climate change is not the solution to increases in electricity demand. As has been experienced in Europe, North America and more recently Asia a combination of decentralised and centralised energy infrastructure is required to address this problem, utilising distributed generation technologies in cities and industrial centres supplemented by centralised energy technologies utilising large scale renewable energy resources, back-up and storage. To that end, this section discusses energy as a portfolio, the implications for infant industry targeting and the baseload concept as a source of maladaptation.

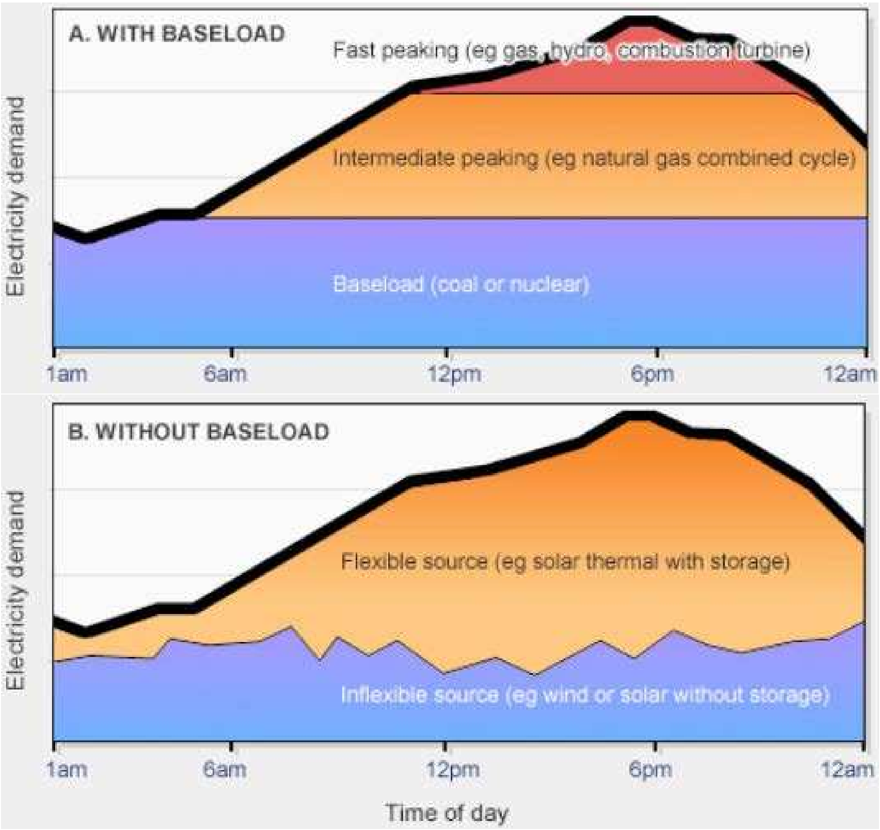
The International Energy Agency (IEA) (2011a, p. 11) finds that having a significant share of renewable energy in a country's energy portfolio can increase energy availability and reduce supply risk. Renewables in an energy portfolio reduce the volatility associated with the price of fossil fuels and reduce supply disruption risk. For instance, the Queensland floods in late 2010 hit the coal mining sector, which reduced supply globally. Similarly, Hurricane Katrina in the US in 2005 put oil prices under upward pressure due to the loss of refining capacities.

In addition to a portfolio between fossil fuels and renewables, there is diversification among renewables, currently the main two main forms are onshore wind and solar PV, other than the traditional hydro. Herein lies the maladjustment, the existing RET schemes and feed-in tariffs reinforce the first mover advantage for onshore wind and solar PV. In addition, solar PV is near market parity (Watt 2011b) without feed-in tariffs. Similarly, onshore wind in New Zealand is being deployed without dedicated support for renewables. However Watt (2011b) concedes that parity is insufficient to induce investment in solar PV as people expect a much quicker payback on capital than calculated by Net Present Value (NPV). So, there is a policy requirement to address people's myopic investment behaviour and to provide a more targeted infant industry assistance to encourage renewables that offer energy profiles differing to solar PV and onshore wind, such as, wave and offshore wind to reduce risk.

Australia will need to move towards a much higher penetration of renewable energy. This is infeasible using intermittent large scale onshore wind energy and small scale solar PV with fossil fuel spinning reserve. The first mover advantage of on-shore wind and solar PV is blocking investment in other renewable energy resources, particularly non-intermittent resources and technologies, which Australia will need to reach a non-intermittent renewable energy future. Incentives, such as scaled incentives for non-intermittency, greater capacity factors or diversity, should be structured so that it contributes to a more resilient decentralised and centralised energy infrastructure much more adaptable to climate change. In Europe, this is achieved through banded feed-in tariffs, other incentives or by energy policy such Germany's Renewable Energy Sources Act (Erneuerbare-Energien-Gesetz or EEG). Section 9.1 further discusses feed-in tariffs and financing investment in renewables and Section 9.4 further discusses RET and encouraging diversification by more selectively targeting infant industries.

A further source of maladaptation to introducing a renewable energy portfolio is the baseload concept that could form psychological anchoring, which detracts focus from developing a renewables energies portfolio to searching unnecessarily for a baseload generator replacement. Figure 6-11 shows how traditionally coal generators produced the baseload power and other forms of generation fit around this baseload. Baseload coal is required to maintain a minimum stable operating level, which has two negative aspects. First is that this minimum stable operating level puts an effective floor on the minimum level of carbon emission reductions that can be secured. Second is that this minimum level produces overnight negative spot prices, which drives out other forms of generation and in particular makes wind generation less economic viable, see Table 6-3. Furthermore, these negative spot prices indicate that coal generators are producing unwanted electricity to maintain their minimum operating output and the associated unwanted carbon dioxide.

Figure 6-11 Meeting demand with and without baseload



(Source: Farrell 2011, p. 26)

Farrell (2011, p. 26) discusses how baseload is unnecessary to meet demand. Figure 6-11 compares the baseload coal scenario in panel A with a renewable alternative that is without baseload in panel B. Panel A shows the relatively inflexible but more constant coal generation or baseload. Panel B shows the inflexible but variable sources of renewable energy such as solar and wind without storage. These variable sources are accommodated by flexible sources such as such as solar with storage. However until sufficient storage and solar thermal capability is developed, there remains an important peaking role for gas along with hydro and pumped hydro (Farrell 2011, p. 24). Similarly, MUREI (2010, p. 32) discusses the potential for solar thermal to balance the variability of wind and to accommodate demand peaks in conjunction with biomass and hydro technologies.

Furthermore, this anchoring effect of baseload provides uncertainty over the future role for gas generators as meeting peak or baseload demand. The uncertainty of the role of gas is illustrated in the following example. Bligh (2011a), the Queensland Premier, discusses the building of two new gas power stations by TRU energy in Gladstone and Ipswich. Bligh (2011a) quotes McIndoe, the Managing director of TRU energy, *"A final decision on the most appropriate technology to match the electricity demand can be* *taken prior to construction. If open cycle technology is used it will be flexible enough to be converted to combined cycle at a later stage as required."* The choice over OCGT or CCGT reflects a choice in role whether peaking or baseload, respectively. This choice has important implications for other generators. For instance Watt (2011a) discusses how the inflexible coal generation base makes Australia least able to accommodate solar PV. If the baseload function of coal is replaced by baseload gas, this transformation could lockout the full potential of a portfolio of renewable energy to replace baseload generation and to reduce price and supply risk, where the commodity boom in coal and gas intensifies the supply and price risk.

6.13 Conclusion

This Chapter finds institutional structure as the source to many maladaptations to climate change. However three are singled out as major sources of maladaptation.

First is the requirement for investment deferment in the transmission and distribution as climate change will accelerate the depreciation of this asset. However, there are dynamics in place that cause over-investment in the intrastate transmission and distribution and underinvestment in the interstate transmission. Chapter 9 further discusses these maladaptations in relation to institutional structure.

Second is the climate change maladaptation induced by fragmentation of the NEM's institutional structure. Chapter 9 discusses fragmentation maladaptation in relation to transmission and distribution, smart grid, RET and feed-in tariffs with a view to developing climate change adaption performance indicators. Section 4.4 discusses how the climate change adaption indicators are used to form a testable proposition about political and market structure.

Third is the RET reinforcing the first mover advantage of onshore wind and solar PV and the requirement to adjust the policy to develop a portfolio of energy technologies. Chapter 9 further discusses the first mover advantage problem for diversified portfolios.

7. THE IMPACT OF CLIMATE CHANGE ON GENERATION AND TRANSMISSION: RESEARCH

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This chapter presents original research on the impact of climate change on generation and transmission in the NEM. Chapter 6 provides a literature review to inform this original research. The combined literature reviews of the project in Chapters 2, 4, 6, 8 and 9 have identified four maladaptations to climate change in the NEM:

1. institutional fragmentation both economically and politically;
2. distorted transmission and distribution investment deferment mechanisms;
3. lacking mechanisms to develop a diversified portfolio of generation technologies and energy sources to reduce supply risk; and
4. failure to model and to treat the NEM as a national node based entity rather than state based.

These four maladaptations are the overarching research questions for the project. This chapter forms smaller research questions to address these overarching research questions.

The original research in this chapter and Chapter 5 address maladaptation 4 directly by modelling the NEM as a national nodal entity rather than state based. The reason for using the node based approach or agent based modelling is that the nodes are related via a network of transmission lines and unless the demand at each node is determined then the network dynamics cannot be determined to reveal any emergent effects. This chapter models the generation capacity and the transmission network using the demand data from Chapter 5 to evaluate the effect of climate change on the following four economic factors:

- spot price;
- energy generated by type of generator;
- carbon emissions; and
- transmission line congestion.

The overarching research questions from the literature reviews are broken down into five smaller research questions, which are addressed in the subsequent sections:

1. Compare the spot price, energy generated, carbon emissions and transmission congestion using projected and actual demand for the base weather year 2009-10 to validate the model projections.
2. Comparing the effect of climate change on the wholesale spot price between the years 2009-10 and 2030-31 with and without a carbon price
3. Comparing the effect of climate change on the energy generated between the years 2009-10 and 2030-31 with and without a carbon price
4. Comparing the effect of climate change on carbon emissions between the years 2009-10 and 2030-31 with and without a carbon price
5. Comparing the effect of climate change on the transmission congestion between the years 2009-10 and 2030-31 with and without a carbon price.

These research questions are addressed with an agent based model called the ANEM model. Appendix C provides a detailed account of the ANEM model. Model projections start in the financial year 2009-10 and finish in 2030-31. This Chapter and Chapter 5 use the climate change parameters discussed in Chapters 2 and 4 and the most suitable weather profile year 2009-10 identified in Chapter 3.

The climate change parameters are repeated below for the convenience of the reader:

- carbon emission scenario SRES A1FI;
- GCM Worst case (hottest) - CSIRO-Mk3.5;
- environment variables; and
    - temperature;
    - solar radiation;
    - relative humidity;
    - wind speed; and
    - rainfall.
- Weather profile year for the baseline of this project.
    - Financial year 2009-10.

Note that in terms of the demand concepts discussed in Chapter 5, the demand concept underpinning the modelling in this Chapter is a *net demand* concept. It can be interpreted as being calculated from gross demand after netting our contributions associated with small scale solar PV and non-scheduled generation (including small and large scale wind, hydro and biomass generation particularly associated with bagasse sourced from sugar cane mills). This net demand concept can also be interpreted as equating to the sum to the output from scheduled and semi-scheduled generation, transmission losses and large independent loads directly connected to the transmission grid.

We have also fixed the generation structure used in the modelling for the period 2009-10 to 2030-31 to the structure listed in Appendix B. In particular, we did not attempt to include any future proposed projects in the analysis because currently too much uncertainty exists relating to both the status and timing of such projects. This reasons for this situation is addressed in more detail in Section C.4. Therefore, given the generation set used in the modelling, our focus clearly is on assessing the supply response of the current generation fleet to the consequences of climate change.

We also incorporated in the modelling the commissioning and de-commissioning of thermal generation plant that occurred over the period 2009-10 to 2013-14. Specifically, the following plant was commissioned:

- Condamine, unit 3 in 2010-11;
- Darling Downs in 2010-11;
- Yarwun in 2010-11; and
- Mortlake in 2011-12.

The following generation was assumed to be de-commissioned:

- Swanbank B:
    - two units in 2010-11;
    - one unit in 2011-12;
    - last unit in 2012-13;
- Collinsville in 2012-13;
- Munmorah in 2012-13;
- Energy Brix, units 3-5 in 2012-13;
- Energy Brix, units 1-2 in 2013-14; and
- Playford B in 2012-13.

We did not, however, include any of the temporary plant closures associated with Tarong, Wallerarang C, Yallourn or Northern power stations that have been recently announced.

In the modelling performed for this Chapter, we also adopted an ‘n’ transmission configuration scenario. This approach involved applying the MW thermal limits determined from the sum of all individual transmission line thermal ratings in the group of transmission lines connecting two nodes. As such, this approach is an *ideal* representation of the transmission grid. In particular, it assumes no transmission line outages and that the capacity of each individual line is not restricted to MW capacities below its rated capacity when all other transmission lines are also operating at their maximum MW rating.

This approach can be contrasted with the more realistic operational setting linked to the 'n-1' transmission scenario which typically involves subtracting the largest individual line from the group connecting nodes. It also follows that in the ‘n’ configuration formulation, evidence of branch congestion is a more serious constraint that can only be alleviated by building additional transmission lines or up-grading existing lines in order to increase their rated MW capacity. As such, congested transmission branches in this scenario will point to structural deficiencies in the current transmission grid. The particular reasons for adopting the ‘n’ transmission configuration scenario are also outlined in more detail in Section C.4.

7.1 Validating the model by comparing projections based on actual and projected demand

This section addresses the first research question:

1. *Compare the spot price, energy generated, carbon emissions and transmission congestion using projected and actual demand for the base weather year 2009-10 to validate the model projections.*

The reason for making the comparison between actual and projected demand for the year 2009-10 is to ensure the veracity of the models findings before addressing the more relevant research questions 2 to 5. If the ANEM model produces similar results using the actual and projected demand for 2009-10, this adds confidence when making comparison between 2009-10 and 2030-31 to evaluate the effects of climate change.

7.1.1 Methodology

The ANEM model described in Appendix C is used to make projections of four economics variables using the actual and projected demand from Chapter 5 for the year 2009-10 and the node structure in Appendix B. The four economic variables include:

- spot price;
- energy generated by type of generator;
- carbon emissions; and
- transmission line congestion.

The methodology involves comparing the closeness of the output of the ANEM model of the four economic variables above based on the actual and projected demand for 2009-10. The output is presented in tables in Section D.2. The methodology employed in this Section is discussed in greater detail in Section D.1.

7.1.2 Results

The results are too lengthy to include in the main text and detract from the more relevant research questions. Sections D.3.1 and D.3.2 present the results.

7.1.3 Discussion

The following discussion provides a summary of the analysis in Appendix D that compares the output of the ANEM model using actual and modelled demand for 2009-10 from Chapter 5. The four outputs from the ANEM model are discussed in turn:

- carbon emissions;
- energy produced by generation type;
- spot prices; and
- transmission line congestion.

7.1.3.1 Carbon emissions

There is less than 0.1 of one per cent difference between the ANEM model's projection of carbon emission using the actual and projected demand from Chapter 5. This high level of comparison holds whether analysing the carbon emissions by state or fuel type.

7.1.3.2 Energy produced by generator type

There is less than 0.1 of one per cent difference between the ANEM model's projection of energy produced by generator type using the actual and projected demand from Chapter 5. This high level of comparison for energy produced by generator type holds whether analysing by fuel type or state.

However, hydro generation has a greater than 0.1 of a per cent difference. The percentage difference in energy produced by generator type for hydro generation in New South Wales was between 1.0 and 1.3 per cent and 0.4 to 0.7 of a per cent in Victoria depending upon carbon price. The ratio of the average production level of hydro generation to its nameplate capacity for New South Wales and Victoria is 0.0003% and 0.008%, respectively. So, average hydro production levels being such a small fraction of total hydro capacity ameliorates any concern over the higher per cent difference for hydro generation.

7.1.3.3 Wholesale spot price

Average spot prices:

Victoria experiences the most difference with the percentage change being in the order of 0.3 to 0.7 of one per cent depending upon carbon price setting. South Australia's difference is in the range of 0.1 to 0.4 of one per cent depending upon carbon price.

Spot price volatility:

Queensland experienced the largest increase in spot price volatility with differences in the range of 0.5 to 0.9 of one per cent depending upon carbon price. Increasing the carbon price from $0/tC0$_2$ to $23/tC0$_2$ reduced the difference between ANEM model's spot price projection based in projected and actual demand. This holds true for both average spot price and spot price volatility.

7.1.3.4 Line congestion

Average power flows

The percentage difference in average power flows on intra-state transmission lines have diminished with an increase in carbon price from \$0/tC02 to \$23/tC0$_2$. Under both carbon pricing scenarios, all intra-state transmission lines have similar values seen in Panel (J) of Tables D-1 and D-2 in Appendix D. The difference in average power flow on inter-state transmission lines is less than 0.2 of one per cent and in many cases, less than 0.1 of one per cent.

Measures of direct branch congestion

The QLD-NSW interconnector (QNI) is the transmission line with the largest difference between simulations based on actual and predicted demand. The difference is 0.1 of one per cent. Depending upon carbon price setting, the Tumut to Regional Victoria line number 37 has up to 0.2 of one per cent difference.

The results seen in Panel (L) of Tables D-1 and D-2 in Appendix D relating to the Marulan-Yass line 31 indicates significant variation in congestion outcomes when using the actual and projected 2009-10 demand profiles. However, ameliorating concerns over these marked percentage difference outcomes is the recognition that these outcomes are coming off an extremely small base congestion value of 0.0005%. As such, the incidence of congestion on this branch is extremely marginal and does not show up in the simulation utilising the actual 2009-10 demand profile.

7.1.4 Conclusion

The results show that the projections for the four economic factors listed below based on the actual and projected demand are extremely close:

- spot price;
- energy generated by type of generator;
- carbon emissions; and
- transmission line congestion.

This result allows us to proceed with some confidence to address the remaining research questions and use the ANEM model to make the comparisons between the years 2009-10 and 2030-31 based on the demand projections for those years.

7.2 Wholesale spot prices

This section addresses the second research question:

2. *Comparing the effect of climate change on the wholesale spot price between the years 2009-10 and 2030-31 with and without a carbon price.*

This research question involves making the comparison between 2009-10 and 2030-31 to evaluate the effects of climate change on wholesale spot prices with a carbon price of \$23/tC0$_2$ and \$0/tC0$_2$.

7.2.1 Methodology

The ANEM model described in Appendices B and C using projected demand from Chapter 5 is used to make projection of the wholesale spot prices from 2009-10 to 2030-31 for the carbon prices of \$23/tC0$_2$ and \$0/tC0$_2$. The differences between the wholesale spot price projections are compared.

Sections E.2 and E.3 discuss the methodology in more detail.

7.2.2 Results

Section E.4 presents the results because they are too lengthy to include in the main body of the book.

7.2.3 Discussion

The following discussion provides a summary of the analysis in Appendix E that compares average spot price and spot price volatility outcomes from ANEM model simulations using modelled demand for the period 2009-10 to 2030-31 and carbon price policy settings. Two carbon price settings were adopted in the simulations. The first related to a carbon price exclusive setting of $\$0/tC0_2$. The second referred to a carbon price inclusive setting of $\$23/tC0_2$.

Two broad scenarios were investigated:

- impact of climate change on spot prices in the absence of a carbon price; and
- impact of a carbon price on spot prices.

7.2.3.1 Impact of climate change on spot prices without a carbon price

The following results are a summary of the discussion presented in Section E.4.1.

From 2009-10 to 2030-31 the average spot prices for Queensland, New South Wales, South Australia and Tasmania rose by 68.7, 85.1, 70.5 and 67.8 per cent, respectively. In contrast for Victoria, the average spot price reduced by 17.4 per cent. This reduction could be attributed to abnormally higher average spot prices in Victoria in 2009-10 and 2010-11 after which Victoria fell back into line with other mainland states.

Analysis of average spot price levels for the period 2009-10 to 2030-31 also showed positive growth in Victorian average spot prices over the period 2012-13 to 2030-31. For example, average spot prices in Victoria grew by 55.3 per cent over the period 2013-14 to 2030-31.

7.2.3.2 Impact of climate change on spot prices with a carbon price of $\$23/tC0_2$

The following results are a summary of the discussion presented in Section E.4.2.

Impact of the carbon price in 2009-10

We use a measure called a carbon pass-through rate to evaluate the effect of a carbon price on wholesale prices. The carbon pass-through rate is calculated by taking the difference between the average spot prices associated with the carbon prices of $\$23/tC0_2$ and $\$0/tC0_2$. This price difference is then divided by the carbon price level $\$23/tC0_2$. See Section E.3.1 for more details.

For 2009-10, the carbon pass-through rate for Tasmania of 0.2434% is significantly lower than other states. This reflects the prominence of hydro generation in this state. The carbon pass-through rate for Victoria of 1.1347% is greater than the pass-through rates of the other states. This reflects the prominence of brown coal fired generation in that state. The pass-through rates for Queensland (0.9252%) and New South Wales (0.9150%) were of a similar magnitude reflecting the similarity in their dependence on black coal generation and Natural Gas Combined Cycle (NGCC) plant. South

Australia's carbon pass-through rate (of 0.8823%) is lower than the other mainland states. This reflects the greater prominence of gas generation in this state.

Impact of the carbon price over the period 2009-10 to 2030-31

There is very little difference between the shapes of the time paths of average spot price levels and spot price volatility for the $0/tC0$_2$ and $23/tC0$_2$ simulations for period 2009-10 to 2030-31, as can be seen in Figures E-1, E-3, E-4 and E-5 of Appendix E.

The rate of change in percentage terms between average spot prices from the $23/tC0$_2$ simulation and average spot prices from the $0/tC0$_2$ simulation when compared on a year-on-year basis over 2009-10 to 2030-31 are larger for Queensland than for New South Wales, Victoria and South Australia. This was caused by the three latter states experiencing higher $0/tC0$_2$ average spot prices than Queensland. This produces lower percentage growth figures by reducing both the size of the numerator and increasing the size of the denominator in rate of change calculations. This result is also consistent with using CSIRO-Mk3.5 GCM to enumerate climate change impacts which tend to be more severe in New South Wales, Victoria and South Australia than in Queensland. As such, New South Wales, Victoria and South Australia would be expected to experience higher average price levels because of climate change than would Queensland, which was observed in Table E-4 of Appendix E.

In Table E-4, in the case of Tasmania, the rate of change in percentage terms is relatively small with the key driving force here being that the carbon price itself only produces a minimal increase in average spot prices associated with the $23/tC0$_2$ simulation compared to the $0/tC0$_2$ simulation. This reflected the small carbon footprint associated with Tasmania's generation fleet which is predominantly hydro generation, implying a relatively small carbon cost impost to be passed into average spot prices.

For all states the percentage change in average spot prices from the $23/tC0$_2$ simulation when compared to the $0/tC0$_2$ simulation decreased in magnitude from 2009-10 to 2030-31 as also outlined in Table E-4. This indicated that average spot prices associated with climate change increasingly dominated the contribution associated with the carbon price itself. That is, the gap between average spot prices from the $23/tC0$_2$ simulation and the $0/tC0$_2$ simulation tended to narrow as time progressed in the interval 2009-10 to 2030-31.

There was also evidence of a declining rate of carbon pass-through for all states over time in the interval 2009-10 to 2030-31. The nature of this decline in carbon pass-through rates also tended to accelerate in general terms over the interval 2009-10 to 2030-31. These results are outlined in Table E-5 of Appendix E, Panels (A) and (B).

7.2.4 Conclusion

These results are based on wholesale spot prices projection which in turn are based on the projected demand from 2009-10 to 2030-31 for the carbon prices of $23/tC0$_2$ and $0/tC0$_2$.

The results show that with or without a carbon price, the impact of climate change will be to increase average spot prices over the period under investigation.

The states with lowest growth in prices will be Tasmania and Queensland and the states with the highest growth in prices will be South Australia and Victoria. These results are consistent with the CSIRO-Mk3.5 GCM that projects more severe climate change in New South Wales, Victoria and South Australia than in Queensland and Tasmania.

Our modelling indicates that the effect of a carbon price on average spot prices will moderate over time. For the mainland states, in 2009-10, increasing the carbon price from \$0/tC0_2 to \$23/tC0_2 was expected to increase the average spot prices from between 53 to 131 per cent depending upon state. In comparison in 2030-31, the average spot price ranges between 34 to 76 per cent.

Recent public debate has focused on the effect that a carbon price might have on wholesale and retail electricity prices. What has not attracted much attention, however, is what the effect of not tackling the consequences of climate change might be. Our modelling indicates that climate change will play a dominant role in increasing wholesale electricity prices and that the rate of pass-through of the carbon price into wholesale electricity prices will diminish over time.

7.3 Energy generated by type of generator

This section addresses the third research question:

3. *Comparing the effect of climate change on the energy generated by type of generator between the years 2009-10 and 2030-31 with and without a carbon price.*

This research question involves making comparisons between 2009-10 and 2030-31 to evaluate the effects of climate change on energy generated by type of generator. It also compares the effect of a carbon price of \$23/tC0_2 and \$0/tC0_2.

7.3.1 Methodology

The ANEM model described in Appendix C is used to make projection of the energy generated by type of generator using projected demand from Chapter 5 for the years 2009-10 to 2030-31 with the node structure in Appendix B for carbon prices of \$23/tC0_2 and \$0/tC0_2. These projections are compared.

The key output metric used to examine generation production trends is the production intensity rate by state for different generation fuel types. Production intensity rates are useful for identifying how the *intensity* of dispatch of different generation technologies might evolve in response to climate change as well as changes in marginal cost relativities associated with the introduction of a carbon price.

The following generation fuel types are considered: all generation; coal-fired generation; gas-fired generation; OCGT generation; hydro generation.

Section F.1 discusses the methodology in more detail, with references to the detailed discussion of concepts and methodology contained in Sections E.2 and E.3.

7.3.2 Results

Section F.2 presents a discussion of the results because they are too lengthy to include in the main body of the book.

7.3.3 Discussion

The following discussion provides a summary of the analysis in Appendix F that compares generator dispatch outcomes by state and generation fuel-type from ANEM model simulations using modelled demand for the period 2009-10 to 2030-31 and two carbon price policy settings adopted in the simulations. The first related to a carbon price exclusive setting of $0/tC$0_2$. The second referred to a carbon price inclusive setting of $23/tC$0_2$.

Two broad scenarios were investigated:

- impact of climate change on generator dispatch by state and fuel-type in the absence of a carbon price; and
- impact of a carbon price on generator dispatch by state and fuel-type.

7.3.3.1 Impact of climate change on generator dispatch without a carbon price

The following results are a summary of the discussion presented in Section F.2.1.

Care needs to be taken in interpreting production intensity rates to determine if movements in rates reflect changes in dispatch patterns or the numeric effect of the averaging process associated with the adding or removal of data in an environment containing generation plant commissioning and de-commissioning which was prevalent over the period 2009-10 to 2013-14.

The most noticeable feature of the results was the relatively benign impact that the climate change impacts included in the regional demand profiles underpinning the carbon price exclusive $0/tC$0_2$ simulation had on the production intensity rates of all types of generation considered over the period 2013-14 to 2030-31. For example, for all generation by state, the percentage rates of change between 2013-14 and 2030-31 production intensity rates were within a range of plus and minus half a per cent. For coal generation, they were within the range of minus half a per cent to 0.6 of a per cent. For gas generation, the similar range was 0.2 of a per cent to 1.2 per cent. In the case of hydro generation, the percentage differences were larger in magnitude but coming from very small production intensity rates in the case of New South Wales and Victoria. For Tasmania which had much more significant production intensity rates, there was a reduction of around half of one per cent over the 2013-14 to 2030-31 period.

In terms of state results, Victoria and South Australia experienced greater rates of percentage increase in ‘all sources’ of generation production intensity rates than occurred in New South Wales over the period 2013-14 to 2030-31. Victoria and South Australia also experienced greater percentage increases in gas generation (particularly in OCGT generation) than did New South Wales over the same period of time. Moreover, for all three states, the percentage increase in OCGT generation over the period 2013-14 to 2030-31 was of a higher order of magnitude than for total gas generation. In general, these results were consistent with the use of CSIRO-Mk3.5 GCM to enumerate the impact of climate change because this GCM produced the most severe impacts of climate change on temperature in Victoria and South Australia, relative to New South Wales.

The results reported for New South Wales were also influenced by competition with production from Queensland. Specifically, Queensland experienced growth in its production intensity rates over the period 2013-14 to 2030-31 for both coal and gas generation relative to the growth experienced in New South Wales. This particularly reflected the export into New South Wales of production from coal and gas plant located in the South West Queensland node which had cheaper cost structures than coal plant located in the Hunter and Central Coast regions of New South Wales. See Appendix B for further details on nodal location and identification of this generation.

In the case of Tasmania, it experienced a reduction in production intensity rate of half a per cent over the period 2013-14 to 2030-31, reflecting reduced production from hydro generation. This result was also consistent with the use of CSIRO-Mk3.5 GCM to enumerate the impact of climate change because this GCM produced the least severe impacts of climate change on temperature in Tasmania and Queensland. In the case of Queensland, we did not see equivalent reductions in production intensity rates because, as mentioned above, some production from Queensland was exported to New South Wales and displaced production located in New South Wales.

A possible reason for the relatively benign impacts of climate change on production intensity rates over the period 2013-14 to 2030-31 was that the analytic methods used were focused at looking broadly at the average consequences or tendencies associated with climate change while ignoring regional or seasonal based variations. For example, to calculate production intensity rates, averaging was performed across generators spread across numerous regions in each state. The measures used also involved temporal averaging across the hourly dispatch intervals within the financial year. Therefore, any differential impacts of climate change occurring across different regions within a state or across time such as seasonal effects would be lost in the averaging process used to calculate the state based production intensity rates.

The averaging methods used would be particularly applicable if the central tendencies implied in projected climate change impacts such as average temperature increases had estimable impacts on regional electricity demand and through this on generation supply response. The patterns observed over the period 2013-14 to 2030-31, in particular, would be consistent with the impact of climate change gradually and smoothly evolving to affect electricity demand in broadly similar ways across the nodes within the transmission grid.

However, if the main effect of climate change on electricity demand is though severe weather impacts implying instances of extreme variation in temperature in summer and winter of limited duration, then these impacts could well be averaged away in the process of deriving the state based measures used in Appendix F.

7.3.3.2 Impact of climate change on generation dispatch with a carbon price of $23/tC0_2$

The following results are a summary of the discussion presented in Section F.2.2.

Impact of the carbon price in 2009-10

We calculated the percentage change between production intensity rates associated with the carbon price inclusive \$23/tC0_2 simulation and the carbon price exclusive \$0/tC0_2 simulation to investigate the potential fuel-switching effects by state associated with the imposition of a carbon price of \$23/tC0_2.

Note that the term ‘fuel-switching’ means changes in generation dispatch patterns whereby the carbon price changes in marginal cost relativities promoting increased production from lower carbon emissions intensive forms of generation and curtailment of production from higher carbon emissions intensive forms of generation. The classical example of fuel-switching is the substitution of production from coal generation by production from gas generation.

The results presented in Section F.2.2.1 indicate that in terms of all sources of generation, Victoria experiences the greatest reduction in production intensity rate, equating to a reduction of around -13.5 per cent. This is followed by South Australia

(-2.2 per cent) and then New South Wales (-1.3 per cent). Queensland experiences an increase of 1.1 per cent while Tasmania experiences a larger increase of 39.4 per cent.

The forces behind the reductions experienced by Victoria and South Australia are reductions in production intensity rates from brown coal generation in Victoria (of -14.3 per cent) and coal generation in South Australia (of -7.8 per cent). Moderating the decline in South Australia is an increase in the production intensity rate of gas generation that is particularly attributable to expansion in production from baseload and intermediate NGCC and gas thermal plant. An expansion in gas generation also occurs in Victoria, but this expansion is coming off much lower production intensity rates when compared to South Australia. Thus, gas plays a much bigger counter-balancing role in South Australia than in Victoria.

In the case of New South Wales, the main force behind the reduction cited above is a reduction in production intensity rate from coal generation of -1.7 per cent. For Queensland, both coal generation and gas generation (mainly from NGCC plant) contribute to the expansion in production intensity rate mentioned above. These latter trends reflect the competitive advantage that coal generation plant located particularly in the South West Queensland node has in terms of age, thermal efficiency, carbon emission intensity and fuel costs when compared to competing New South Wales coal generation plant located at the Liddell, Bayswater and Central Coast nodes in New South Wales – see Appendix B for details. This competitive advantage enables the Queensland plant to partially displace production from the New South Wales coal plant through exports of power into New South Wales especially given their proximity to the QNI Interconnector.

In the case of Tasmania, the increase in production intensity rate is associated with an expansion in production intensity rate of hydro generation in that state (of 41.2 per cent). A key factor behind the expansion in hydro production in Tasmania is the relative improvement in the competitive position of hydro generation relative to competing thermal plant in Tasmania and Victorian following the imposition of the carbon price of $\$23/tC0_2$. This follows because the carbon price does not affect the marginal costs of hydro generators whereas it increases the marginal costs of competing thermal generators. Moreover, some hydro plant in Tasmania have marginal cost structures significantly lower than their mainland counterparts because they are expected to be able to meet baseload and intermediate production duties. Thus, in assessing competitive advantage, they are starting from a lower base than mainland hydro plant, which also improves their competitive position relative to Victorian brown coal plant in a policy environment containing a carbon price of $\$23/tC0_2$.

Impact of the carbon price over the period 2009-10 to 2030-31

Section F.2.2.2 examined the impact that the carbon price had over the whole period 2009-10 to 2030-31 relative to the results obtained from the carbon price exclusive $\$0/tC0_2$ simulation. Recall that this latter simulation incorporated climate change impacts in a policy environment containing no carbon price.

We found that in the case of Queensland, the carbon price impact overtime acted to reinforce the growth in production from coal and gas generation associated with the $\$0/tC0_2$ simulation results although this reinforcement effect diminished over the period 2013-14 to 2030-31.

For New South Wales, the impact of the carbon price over time was to reinforce the slight decline experienced in the production intensity rate of coal generation associated with the $\$0/tC0_2$ simulation over the period 2013-14 to 2030-31.

For Victoria, the impact of the carbon price was to strongly reinforce the slight trend reduction in the production intensity rate of coal generation associated with the $0/tC$0_2$ simulation over the period 2013-14 to 2030-31. This negative reinforcement effect, however, declined in magnitude over the duration of the 2013-14 to 2030-31 time interval.

The impact of the carbon price was to reinforce the reduction in the production intensity rate for coal generation from the $0/tC$0_2$ simulation over the period 2013-14 to 2030-31 in South Australia although at a diminishing rate. The effect of the carbon price also acted to moderate the expansion in gas generation observed under the $0/tC$0_2$ simulation over the period 2013-14 to 2030-31, however, also at a diminishing rate.

In the case of Tasmania, the main impact of the carbon price is to reinforce the expansion in hydro generation associated with the $0/tC$0_2$ simulation but at a diminishing rate over the period 2013-14 to 2030-31.

7.3.4 Conclusion

The results show the projections for energy generated by state and fuel-type based on the projected demand for the years 2009-10 and 2030-31 for the carbon prices of $23/tC$0_2$ and $0/tC$0_2$.

The major conclusion from the research reported in Appendix F relate to the consistency of our findings about generation dispatch patterns with the use of the CSIRO-Mk3.5 GCM to quantify the impact of climate change by state.

We found similarity in outcomes for both Queensland and Tasmania. There is growth in production intensity rates albeit from different types of generation, however, at a declining rate over the time period 2013-14 to 2030-31. These results are consistent with the use of CSIRO-Mk3.5 GCM to quantify the impact of climate change because this GCM downplays the impact of climate change on temperature in both Queensland and Tasmania when compared to the other states. This would explain the nature of the diminishing rate of positive reinforcement experienced by both states over time.

The other two states experiencing similar outcomes are Victoria and South Australia. The key impact of the carbon price is to reduce the production intensity rates obtained relative to those rates associated with the $0/tC$0_2$ simulation. However, over time, this fuel-switching effect associated with the carbon price declines in strength. These results are consistent with the use of CSIRO-Mk3.5 GCM to enumerate the impact of climate change because this GCM produces to most severe impacts of climate change on temperature in Victoria and South Australia. This effect would help to explain why the fuel-switching effect associated with the carbon price diminishes in strength for both states over time.

The state with mixed results is New South Wales. The impact of the carbon price reinforces a decline experienced in coal generation and moderates expansions occurring in gas generation. Therefore, the overall trend effect in New South Wales over time is towards a reduction in the production intensity rate in both 'all generation' and coal generation in an environment of increasing demand flowing from the impact of climate change.

A possible explanation of these trends is the substitution of New South Wales production by production from Queensland – especially by coal and NGCC plant located in the South West Queensland node which are well placed to compete with

New South Wales coal generation in the Hunter Valley and central Coast regions and, additionally, are well placed to export power into New South Wales on the QNI Interconnector – see Appendix B for further details.

7.3.5 Further Research

There would be value in performing analysis on a more disaggregated region by region basis as well as also breaking up the time dimension to focus at least on summer and winter effects.

If severe weather events are thought to govern demand responses, then value would also be found in concentrating analysis on these limited duration events.

It would also be worthwhile to perform analysis on the basis of half hourly dispatch intervals. This would facilitate a combination of more variable demand and more restrictive generator ramping constraints which is likely to elicit a different generator supply response from ANEM model simulations than was obtained from the hourly based dispatch simulations reported in Appendix F.

Running simulations utilising the ‘n-1’ transmission configuration instead of the ‘n’ configuration discussed in Section C.4 would also elicit a different generator supply response than obtained in the simulations reported in Appendix F. In particular, this would enable investigation of potential islanding effects on generation associated with the reduced capacity of the transmission system.

7.4 Carbon emissions

This section addresses the fourth research question:

4. *Comparing the effect of climate change on carbon emissions between the years 2009-10 and 2030-31 with and without a carbon price.*

This research question is addressed by making comparisons between 2009-10 and 2030-31 to evaluate the effects of climate change on carbon emissions from electricity generation. It also compares the effect of a carbon price of $23/tC0$_2$ and $0/tC0$_2$.

7.4.1 Methodology

The ANEM model described in Appendix C is used to make projection of carbon emissions from electricity generation using projected demand from Chapter 5 for the years 2009-10 to 2030-31 with the node structure outlined in Appendix B for carbon prices of $23/tC0$_2$ and $0/tC0$_2$. These projections are compared.

The key output metrics used in this Section is carbon emissions produced from electricity generation by state and fuel type. The generation fuel types considered are:

- all generation;
- coal-fired generation; and
- gas-fired generation.

Section G.1 discusses the methodology in more detail, with references to more detailed discussion of concepts and methodology outlined in Sections E.2 and E.3.

7.4.2 Results

The results are too lengthy to include in the main body of the book and are, instead, presented in Section G.2.

7.4.3 Discussion

The following discussion provides a summary of the analysis in Appendix G that compares carbon emission outcomes by state and generation fuel-type from ANEM model simulations using modelled demand for the period 2009-10 to 2030-31 and two particular carbon price settings. The first was related to a carbon price exclusive setting of \$0/tC0_2. The second referred to a carbon price inclusive setting of \$23/tC0_2.

Two broad scenarios are investigated:

- impact of climate change on carbon emissions by state and fuel-type in the absence of a carbon price; and
- impact of a carbon price on carbon emissions by state and fuel-type.

7.4.3.1 Impact of climate change on carbon emissions by state and fuel-type in the absence of a carbon price

The following results are a summary of the discussion presented in Section G.2.1.

There are some step changes in carbon emission outcomes occurring over the period 2009-10 to 2013-14 associated primarily with plant de-commissioning. In the case of Queensland, there are a series of reductions occurring over the period 2010-11 to 2012-13 associated with the decommissioning of Swanbank B power station. Growth in carbon emissions from the newly commissioned Queensland NGCC plant in 2010-11 goes some way to partially offsetting the reductions associated with the de-commissioning of Swanbank B. For New South Wales, there is some ramp up in carbon emission from gas generation in 2012-13, most likely in response to the closure of Munmorah Power station.

In the case of Victoria, there is a reduction in carbon emissions over the period 2012-13 to 2013-14 associated with the de-commissioning of Energy Brix power station. There is also an increase in carbon emissions from gas generation occurring mainly in 2012-13, providing some partial offsetting of the reduction attributable to the de-commissioning of Energy Brix.

The results for South Australia indicate a sizable reduction in carbon emissions during 2012-13 associated with the de-commissioning of Playford B power station. There was some partial counter-balancing from growth in carbon emission from gas generation in South Australia also in this year.

There was no change in carbon emissions in Tasmania over the period 2009-10 to 2013-14 because the Tamar valley NGCC plant continued to be dispatched at production levels close to its minimum stable operating level over this period.

The other noticeable feature evident in all panels of Table G-1 in Appendix G was the relatively benign growth in carbon emissions over the time period 2013-14 to 2030-31, broadly following the trends identified in Appendix F in relation to generation production trends by state and fuel type. For all sources of generation, the growth in carbon emissions by state over the period 2013-14 to 2030-31 fell in the range of -0.46 to 0.20 of one per cent. For carbon emissions from coal generation, the equivalent range was -

0.85 to 0.21 of one per cent. For carbon emissions from gas generation, the range was -0.27 to 0.38 of one per cent.

It also emerged that Queensland experienced growth in carbon emissions over the period 2013-14 to 2030-31 with growth in carbon emissions from coal and gas generation also occurring. The experience for New South Wales, Victoria and South Australia is similar. Specifically, they all experienced further reductions in carbon emission levels in 2030-31 relative to the levels in 2013-14 with the principal driving force behind these trends being reductions in carbon emissions from coal generation over the period 2013-14 to 2030-31. In the case of Victoria, growth in carbon emissions from gas generation over the same period played a partial offsetting role.

7.4.3.2 Impact of a carbon price of $23/tC0$_2$

The following results are a summary of the discussion presented in Section G.2.2.

Impact of the carbon price in 2009-10

In Section G.2.2.1, we calculated the percentage change between carbon emissions by state and fuel type associated with the carbon price inclusive \$23/tC0$_2$ simulation and the carbon price exclusive \$0/tC0$_2$ simulation. This measure was used to investigate the nature of any reduction in carbon emissions associated with potential fuel-switching effects by state associated with the imposition of the carbon price of \$23/tC0$_2$.

In terms of total generation, the impact of the carbon price of \$23/tC0$_2$, relative to the 2009-10 Business-As-Usual (BAU) levels, was to reduce carbon emissions in Victoria by the largest magnitude (-8.1 per cent), followed by South Australia (-2.3 per cent) and then New South Wales (-0.4 of one per cent). Queensland, on the other hand, experiences an increase in carbon emissions relative to 2009-10 (\$0/tC0$_2$) BAU levels of 1.5 per cent. For the NEM, carbon emissions decline by -2.5 per cent. These results broadly match the production trends reported in Section F.2.2.1.

The outcomes reported for Victoria, Queensland, New South Wales and the NEM principally follow trends occurring in carbon emissions from coal generation. In the case of South Australia, the aggregate carbon emission outcome is influenced by trends emerging from both coal and gas generation in that state. In particular, the reduction in carbon emissions from coal generation is partially offset from growth in carbon emissions from increased production from gas generation.

Impact of the carbon price over the period 2009-10 to 2030-31

Section G.2.2.2 examined the impact that the carbon price had on carbon emissions over the whole period 2009-10 to 2030-31 relative to the results obtained from the carbon price exclusive \$0/tC0$_2$ simulation. Recall that this latter simulation incorporated climate change impacts in a policy environment containing no carbon price.

Over the period 2009-10 to 2030-31, the impact of the carbon price is to increase carbon emissions in Queensland relative to the \$0/tC0$_2$ levels with the positive reinforcement effect increasing slightly over time. For New South Wales, the impact of the carbon price is to reduce the level of carbon emissions relative to the \$0/tC0$_2$ levels. The year-on-year effect of this negative reinforcement is quite variable in scope but, in overall terms, seems to increase slightly over the period 2013-14 to 2030-31.

Victoria and South Australia experience similar trends. The impact of the carbon price is to reduce carbon emissions relative to \$0/tC0$_2$ levels. However, this negative reinforcement effect diminishes in magnitude over time. The results for the NEM also reflect this particular trend as well, ignoring a few outlier impacts around 2023-24 and 2024-25.

In the case of Tasmania, apart from some small outliers in 2023-24 and 2024-25, the carbon price does not change emission outcomes from those associated with the $0/tC0$_2$ simulation. This reflects the continued dispatch of the Tamar Valley NGCC plant at levels close to its minimum stable operating level over the period 2009-10 to 2030-31 under both the $23/tC0$_2$ and $0/tC0$_2$ carbon price settings.

7.4.4 Conclusion

The results show projections for carbon emission levels by state based on the projected demand for the years 2009-10 and 2030-31 for the carbon prices of $23/tC0$_2$ and $0/tC0$_2$.

We identified the following impacts of climate change by state in the absence of a carbon price. For Queensland, this state experienced growth in carbon emissions over the period 2013-14 to 2030-31, reflecting positive contributions from both coal and gas generation in that state. In the cases of New South Wales, Victoria and South Australia, the impact was to produce further reductions in carbon emissions by 2030-31 relative to the levels existing in 2013-14, principally reflecting reductions in carbon emissions from coal generation. In the case of Victoria, growth in carbon emissions from gas generation played a partial offsetting role.

The main impact by state of a carbon price of $23/tC0$_2$ was to reduce carbon emissions obtained relative to those rates associated with the $0/tC0$_2$ simulation in the case of Victoria and South Australia. However, over time, this negative reinforcement effect declined in strength ensuring that the magnitude of reduction in carbon emissions diminished over time. This outcome is consistent with the use of CSIRO-Mk3.5 GCM to enumerate the impact of climate change because this GCM produces the most severe impacts of climate change in terms of temperature on Victoria and South Australia. This would help explain why the fuel-switching effects promoting carbon emission reductions associated with the carbon price diminishes in strength for both states over time.

In the case of Queensland, there is growth in carbon emissions relative to $0/tC0$_2$ simulation results, and with this positive reinforcement effects being fairly constant over time, if not having a very slight upward bias. The state with somewhat mixed results is New South Wales. The impact of the carbon price reinforces a decline experienced in carbon emissions under the $0/tC0$_2$ simulation. Moreover, the magnitude of the negative reinforcement effects generally increases over the period 2013-14 to 2030-31. These trends match the production intensity rate outcomes described in Section F.2.2.2. Therefore, the overall trend effect in New South Wales over time is towards a reduction in carbon emissions in an environment of increasing demand flowing from the impact of climate change.

However, once again, a possible explanation of these trends is linked to potential substitution of New South Wales coal generation production located in the Hunter and Central Coast regions of New South Wales by production sourced from Queensland coal and NGCC plant located in the South West Queensland node.

7.4.5 Further Research

There would be value in disaggregating the carbon emission results reported in this Section and Appendix G and production trends reported in Section 7.3 and Appendix F to investigate the possibility of substitution arising between different types of gas generation plant, particularly in relation to New South Wales and South Australia.

7.5 Transmission line congestion

This section addresses the fifth research question:

5. *Comparing the effect of climate change on the transmission line congestion between the years 2009-10 and 2030-31 with and without a carbon price.*

This research question is investigated by making comparisons between 2009-10 and 2030-31 to evaluate the effects of climate change on transmission branch utilisation and congestion. It also compares the effect of a carbon price of \$23/t$C0_2$ and \$0/t$C0_2$.

7.5.1 Methodology

The ANEM model described in Appendices B and C is used to make projections of transmission branch utilisation and congestion rates using projected demand from Chapter 5 for the years 2009-10 to 2030-31 for carbon prices of \$23/t$C0_2$ and \$0/t$C0_2$. These projections are compared.

The key output metrics used in this Section are measures of transmission branch utilisation and congestion that are built around average MW power flows on transmission lines expressed as a proportion of that transmission lines maximum thermal MW rating. An increase in this proportional value would point to increased utilisation of the transmission line.

A quantitative measure of branch congestion is also calculated by expressing the number of times in a year that actual power flows equate with the MW thermal limit of a transmission line and expressing this number as a proportion of the total number of dispatch intervals in the year.

Section H.1 discusses the methodology in more detail.

7.5.2 Results

The results are too lengthy to include in the main body of the book and are, instead, presented in Section H.2.

7.5.3 Discussion

The following discussion provides a summary of the analysis in Appendix H that compares transmission branch utilisation and congestion rates from ANEM model simulations using modelled demand for the period 2009-10 to 2030-31 and two particular carbon price settings. The first was related to a carbon price exclusive setting of \$0/t$C0_2$. The second referred to a carbon price inclusive setting of \$23/t$C0_2$.

Two broad scenarios are investigated:

- impact of climate change on transmission branch utilisation and congestion in the absence of a carbon price; and
- impact of a carbon price on transmission branch utilisation and congestion.

7.5.3.1 *Impact of climate change on transmission branch utilisation and congestion without a carbon price*

The following results are a summary of the discussion presented in Section H.2.1.

Average power flows on the inter-state interconnectors were in the normal direction for the period 2009-10 to 2030-31. Therefore, on average, we obtained power flows from Queensland to New South Wales on QNI and Directlink; from New South Wales to Victoria on Tumut-Murray, Tumut-Dederang and Tumut-Regional Victoria; from Victoria to Tasmania on Basslink; and from Victoria to South Australia on the Heywood and Murraylink interconnectors. Appendix B can be consulted for further details about the location of these transmission lines and connected terminal nodes. Also see Section C.2.1 for further details about direction of power flows on transmission branches.

Transmission branch utilisation rates

There was increased utilisation over the period 2010-11 to 2030-31 on QNI, Tumut-Murray, Tumut-Dederang, Tumut-Regional Victoria, Heywood and Murraylink relative to the 2009-10 utilisation rates. There was reduced utilisation on Directlink and Basslink over the same period of time relative to the 2009-10 utilisation rates. Over the period 2013-14 to 2030-31, slight reductions in utilisation rates were recorded on QNI, Directlink, Tumut-Murray, Tumut-Dederang, Tumut-Regional Victoria, and Murraylink. Over this same time period, slight increases in utilisation rates were recorded on the Basslink and Heywood interconnectors.

It should be recognised that we restricted analysis in Appendix H to intra-state transmission branches experiencing increased utilisation rates over the period 2010-11 to 2030-31 when compared with 2009-10 utilisation rates. For these particular intra-state transmission branches, there were generally slight reductions in utilisation rates experienced on intra-state transmission lines located in New South Wales, Victoria and South Australia over the period 2013-14 to 2030-31. In the case of transmission lines located in Queensland, there were generally slight increases in utilisation rates recorded over this same time period.

The number of inter-state and intra-state transmission branches experiencing increases in utilisation rates relative to 2009-10 rates, equated to 60 per cent of all transmission branches in the ANEM model. Therefore, 40 per cent of all branches in the ANEM model experienced reductions in utilisation rates over the period 2010-11 to 2030-31 relative to 2009-10.

Transmission branch congestion rates

Incidence of branch congestion was recorded for QNI, Tumut-Regional Victoria, Basslink and Murraylink, with the greatest degree of congestion being experienced on Basslink, followed by QNI, Tumut-Regional Victoria and finally Murraylink. Over the period 2013-14 to 2030-31, the degree of congestion declined slightly on QNI and Tumut-Regional Victoria, while increasing slightly on Basslink and Murraylink.

Only two intra-state transmission branches experienced congestion. These were Marulan-Yass and Yallourn-Melbourne. Congestion occurred at much higher rates on the second transmission branch and appeared to be an extremely marginal occurrence on the first branch.

7.5.3.2 Impact of a carbon price of \$23/tC0$_2$

The following results are a summary of the discussion presented in Section H.2.2.

Impact of the carbon price over the period 2009-10 to 2030-31

Section H.2.2 examined the impact that a carbon price of \$23/tC0$_2$ had on transmission branch utilisation and congestion rates over the whole period 2009-10 to 2030-31 relative to the results obtained from the carbon price exclusive \$0/tC0$_2$ simulation. Recall that this latter simulation incorporated climate change impacts in a policy environment containing no carbon price.

Transmission branch utilisation rates

The carbon price of \$23/tC0$_2$ had the effect of positively reinforcing the utilisation rates associated with the carbon price exclusive \$0/tC0$_2$ simulation on all inter-state interconnectors except for Basslink. As such, the carbon price had the effect of increasing the branch utilisation rates above the rates that were obtained from the BAU \$0/tC0$_2$ simulations. The positive reinforcement, however, diminished over the period 2013-14 to 2030-31 except for the case of Directlink which experienced a slight increase in reinforcement over this same time period.

In the case of Basslink, the effect of the carbon price was to negatively reinforce the utilisation rate obtained from the carbon price exclusive \$0/tC0$_2$ simulation. Therefore, in this particular case, the carbon price had the effect of reducing the utilisation rate from the rate obtained from the BAU \$0/tC0$_2$ simulations. However, this negative reinforcement also diminished over the time period 2013-14 to 2030-31 and particularly so from 2020-21. Section H.2.2.1 can be consulted for further details.

The results for the utilisation rates on intra-state transmission branches associated with the carbon price indicated that North Queensland-Central West Queensland, South West Queensland–Moreton South and Lismore-Armidale branches experienced negative reinforcement of the utilisation rates associated with the BAU \$0/tC0$_2$ simulations. All other intra-state transmission branches experienced positive reinforcement associated with the carbon price, although the positive reinforcement effects generally diminished over the time period 2013-14 to 2030-31.

The imposition of a carbon price of \$23/tC0$_2$ also seemed to produce a marked change in utilisation rates dynamics. Specifically, the number of transmission branches experiencing increased utilisation rates relative to 2009-10 rates fell from 60 per cent (under BAU \$0/tC0$_2$) to 39 per cent while the number of branches now experiencing reduced utilisation rates increased from 40 per cent (under BAU \$0/tC0$_2$) to 61 per cent.

Transmission branch congestion rates

The impact of the \$23/tC0$_2$ carbon price was to increase branch congestion on QNI, Tumut-Regional Victoria and Murraylink. In the case of both QNI and Murraylink, the magnitude of positive reinforcement diminished over the time period 2013-14 to 2030-31 while in the case of Tumut-Regional Victoria, the extent of positive reinforcement strengthened over the same time period.

In the case of Basslink, the carbon price produced negative reinforcement of congestion rates associated with the BAU \$0/tC0$_2$ simulations. The negative reinforcement also diminished over the time period 2013-14 to 2030-31. These outcomes broadly mirrored the trends identified above in relation to utilisation rates for this particular branch. Specifically, the degree of branch congestion increased markedly over the period 2020-21 to 2023-24 and then closely approximated the BAU $\$0/tC0_2$ simulation results over the period 2024-25 to 2030-31.

As identified in Section H.2.1, only two intra-state transmission lines recorded any incidence of branch congestion. These were the Marulan-Yass and Yallourn-Melbourne transmission branches. Congestion was much more significant on the Yallourn-Melbourne line although the carbon price appeared to marginally relieve this pressure over the period 2009-10 to 2023-24, although generally at a diminishing rate. From 2024-25 onwards, the congestion rates associated with both the $\$23/tC0_2$ and $\$0/tC0_2$ simulations coincided.

7.5.4 Conclusion

In general terms, the impact of the carbon price on transmission branch utilisation and congestion, irrespective of whether it promotes positive or negative reinforcement relative to the BAU carbon price exclusive ($\$0tC0_2$) simulation outcomes, typically diminishes over the time interval 2013-14 to 2030-31. This means that over time, the results from the carbon price inclusive ($\$23/tC0_2$) simulation tends to approach the results associated with the carbon price exclusive ($\$0/tC0_2$) simulation. While there are always some individual exceptions to this rule, in overall terms, the above trend typically arises in most cases. This further supports the argument also made in Appendices E and F that the effects of climate change tends to dominate the impacts of the carbon price as time evolves over the interval 2013-14 to 2030-31.

The implications of average power flows arising on QNI and the intra-state transmission lines connecting Lismore, Armidale, Tamworth and Liddell provide direct support for the export of power from the south west Queensland node to the Hunter Valley region of New South Wales. These average power flows confirmed the production substitution effects identified in Appendix F involving the substitution of production from the Hunter Valley-Central Coast regions of New South Wales with production from south west Queensland.

The significant degree of branch congestion on the Yallourn-Melbourne branch also points to a structural deficiency. Increasing the megawatt (MW) thermal capacity limit of this branch would be expected to help to reduce spot price levels and spot price volatility in Victoria while also increasing the avenues of potential supply of generation from the La Trobe Valley to the Greater Melbourne Region.

Another structural deficiency that was identified was the limited thermal capacity and transfer capabilities on the inter-state interconnectors linking Tumut (New South Wales), Regional Victoria and Riverlands (South Australia). These are the inter-state interconnectors which connect Tumut-Regional Victoria and the Murraylink interconnector connecting regional Victoria-Riverlands (South Australia).

There are a number of particular concerns with these transmission branches. First they are single 220 kilovolts (kV) circuits and are vulnerable to power flow disruptions associated with line outage events. Second, the power flow on these interconnectors are also dependent upon local 132 kV or 220 kV networks that connect to the major 275kV, 330 kV or 500 kV transmission pathways in South Australia, New South Wales and Victoria. To increase the thermal capacity of power transfers on the inter-state interconnectors would also require similar work to be performed on the local transmission networks these interconnectors connect to if enhanced transfer capability is to reach the high voltage transmission networks servicing the major load centres in all three states.

These considerations become even more pressing when account is taken of the existing and proposed renewable energy projects located in the Broken Hill area (wind and solar), regional Victoria (wind) and mid north South Australia (wind).

Other noticeable congestion points are the Basslink and QNI interconnectors with the findings pointing to the current thermal limits of Basslink and QNI affecting power transfers from Victoria to Tasmania and from Queensland to New South Wales.

It was recognised that the proposed NEMLink proposal outlined in AEMO (2011b) would go a long way to meeting the expansion requirements mentioned above. This would particularly apply to renewable energy projects located in the mid north South Australia and regional Victoria nodes as well as facilitating greater scope for power transfers between Victoria and Tasmania and Queensland and New South Wales. This would help alleviate any capacity constraints emerging on the Basslink and QNI Interconnectors. However, this proposal, in its current form, is not so well placed to meet any widespread development of renewable energy projects in newly emerging areas such as Broken Hill, upper north South Australia or the western reaches of the Otway Basin, for example.

7.5.5 Further Research

The results obtained relating to transmission branch utilisation and congestion findings are very dependent upon the ‘n’ transmission configuration settings adopted for the simulations in this project. However, running simulations utilising the ‘n-1’ transmission configuration settings instead, as discussed in Section C.4, would elicit different utilisation and congestion rate outcomes. This would operate particularly by reducing the thermal limits on transmission lines associated with the ‘n-1’ transmission configuration when compared with the comparable limits associated with the ‘n’ configuration settings.

The transmission branch limits adopted relate to thermal MW limits. Other limit concepts, however, are available which might further constraint the effective ‘carrying capacity’ of the transmission branches to effective MW limits that are lower in magnitude than the thermal limits used in this project. Two sets of alternative transmission capacity limit concepts suggest themselves. The first refers to limits associated with voltage or oscillatory stability considerations. The second set refers to transient stability limits. An area of further research would be to include these other transmission limit capacity concepts in the analysis. One approach to accomplishing this would be to incorporate these additional limits into the modelling by adding in the constraint equations related to these particular limits as developed by the AEMO to the ANEM model.

7.6 Discussion

Sections 7.2, 7.3, 7.4 and 7.5 present and discuss the results of a smaller set of research questions that compare the effect of climate change on:

1. wholesale spot prices;
2. energy generated;
3. carbon emissions; and
4. transmission congestion, respectively,

between the years 2009-10 and 2030-31 with and without a carbon price.

These smaller questions are developed from the project's overarching research questions or four sources of maladaptation to climate change listed below:

1. institutional fragmentation both economically and politically;
2. distorted transmission and distribution investment deferment mechanisms;
3. lacking mechanisms to develop a diversified portfolio of generation technologies and energy sources to reduce supply risk; and
4. failure to model and to treat the NEM as a national node based entity rather than state based.

This Section relates the findings from Sections 7.2 to 7.5 back to the overarching research question for the project. The discussion in this Chapter will focus on the impacts relating to generation and particularly transmission.

The original research in this Chapter, drawing on research presented in Chapter 5 addressed maladaptation 4 directly by modelling the NEM as a national nodal entity rather than state based. The reason for using the node based approach or agent based modelling is that the nodes are related via a network of transmission lines and unless the demand at each node is determined then the network dynamics cannot be determined to reveal any emergent effects.

This Chapter modelled generation capacity and the transmission network using the demand data from Chapter 5 to evaluate the effect of climate change on the following four economic factors:

- spot price;
- energy generated by type of generator;
- carbon emissions; and
- transmission line congestion.

A number of substantive findings can be drawn from this research.

First, the current generation fleet and transmission network outlined in Appendix B was able to produce both generator supply responses and power flows on transmission branches to satisfy the nodal demand profiles developed in Chapter 5 and used in the modelling over the time interval 2009-10 to 2030-31.

Second, our modelling indicated that with or without a carbon price, climate change will play an important role in increasing wholesale electricity prices in the future.

Third, the rate of pass-through of the carbon price into wholesale electricity prices by state diminished over time.

Fourth, the impact of climate change was incorporated into the projected regional demand profiles produced by the methods outlined in Sections 5.2 and 5.3. These regional demand profiles were then used in the modelling in this Chapter for the period 2009-10 to 2030-31. Over this period, the impact of climate change in a policy environment containing no carbon price signal was encapsulated in the results associated with the carbon price exclusive ($\$0/tC0_2$) simulations. The results obtained from these simulations in relation to average spot price levels by state and generation dispatch by state and fuel type were generally consistent with use of the CSIRO-Mk3.5 GCM that projected more severe climate change impacts in New South Wales, Victoria and South Australia than in Queensland and Tasmania.

A substitution effect was also identified involving the partial substitution of production in the Hunter Valley and Central Coast regions of New South Wales by production sourced from south west Queensland and exported into New South Wales on the QNI interconnector. Simulation results relating to generation dispatch by state and fuel type as well as average power flow and branch congestion outcomes strongly pointed to this substitution effect.

Fifth, the impacts of climate change tended to dominate the impacts of the carbon price over time. This was observed for a number of variables including average spot prices by state, generation production intensity rates by state and fuel type, carbon emissions by state and fuel type and average power flows on inter-state interconnectors and inter-state transmission branches experiencing increased utilisation rates.

This trend typically showed up in the form of positive or negative reinforcement of results associated with the benchmark carbon price exclusive ($\$0/tC0_2$) simulation that diminished over the time period 2013-14 to 2030-31. This implied that over time the results associated with the carbon price inclusive ($\$23/tC0_2$) simulation tended to converge towards the results associated with the benchmark carbon price exclusive ($\$0/tC0_2$) simulations. Recall that the latter simulations incorporated the impacts of climate change but in a policy environment that did not contain a carbon price signal.

Sixth, a number of structural deficiencies were identified in relation to the transmission grid. These deficiencies were related to congestion on the following transmission lines identified in Appendix B:

- QNI (line 11);
- Tumut to Regional Victoria (line 37);
- Basslink (line 42);
- Yallourn to Melbourne (line 46). and
- Murraylink (line 50);

While all of the above are critical deficiencies, perhaps the most strategic is the lack of capacity and transfer capability associated with congestion on lines 37 and 50 which link key regional areas containing many existing and proposed intermittent renewable energy projects including mid north South Australia (wind), regional Victoria (wind) and the Broken Hill region of New South Wales (proposed wind and solar).

The NEMLink proposal outlined in AEMO (2011b) would go a long way to addressing the expansion requirements mentioned above, particularly in relation to renewable energy projects located in mid north South Australia and regional Victoria as well as congestion on Basslink and QNI. However, in its current form, the proposal is not well placed to meet any widespread development of renewable energy projects in newly emerging areas such as Broken Hill, upper north South Australia, Glen Innes area of New South Wales or the western reaches of the Otway Basin, for example.

As addressed in Chapter 5, the methods and techniques used for both assessing transmission system adequacy and transmission expansion planning are linked to the network adequacy to meet peak load demand. They key criteria encapsulated in the RIT-T procedure that is currently applicable is to rank the various transmission investment options and identify the option that maximises net economic benefits. This current framework has removed any distinction in the regulatory test between reliability driven projects and projects motivated by the delivery of market benefits. This analysis is based on quantifying various categories of costs and benefits arising in the NEM. See AEMO (2013) for further details.

This type of procedure would work very well in situations involving the upgrading of or addition to existing network components that are servicing significant load centres. Under such circumstances, well defined market signals relating to price and quantity will be derivable and economic costs and benefit as well as net economic benefit can be readily assessed. Moreover, detailed power flow analysis and the derivation of such things as constraint equations would generally be available, having been derived by TNSP or AEMO.

The situation becomes more difficult if we move away from well-defined grid and market structures to more remote areas with low load factors which might be applicable to the location of renewable energy projects. In this case, focus would switch from meeting peak load demand to the goals and assessment of costs and benefits of supplying renewable energy. As such, the market structure and signals underpinning assessment of economic benefits and costs under RIT-T might be less well developed or defined, making it very difficult to get project approval on the basis of net economic benefit arguments. In this case, subsequent construction and operation as a prescribed transmission service with funding on the basis of a network tariff would be unlikely.

Furthermore, from a public policy perspective, the goals or objectives associated with promoting investment in renewable energy are different conceptually from those underpinning transmission adequacy assessments under the RIT-T process. Specifically, proposals aimed at promoting investment in renewable energy are linked to environmental policy goals aimed at combating the adverse effects of climate change through reducing carbon emissions by promoting fuel-switching to renewable energy generation technologies.

The time path of economic and environmental costs and benefits associated with reducing carbon emissions, however, might be harder to quantify and include in net economic value calculations. Instead, in the current policy environment, it is likely to fall to the renewable energy project proponents to have to fund any significant transmission infrastructure investments as part of the project and depend upon revenue earned from both the wholesale market and Large-scale Renewable Energy Target (LRET) revenue to fund these investments instead of on the basis of some regulated network tariff received by TNSP's. To the extent that these considerations may combine to preclude finalisation of the renewable energy project by the proponent, then this type of outcome would fall under both the second and third sources of maladaptation to climate change mentioned above.

However, the ability to model the NEM as a national nodal based entity could help alleviate this by establishing well defined nodal and market structures in even remote areas. Recall that in the agent based modelling approach, the transmission grid can be viewed as a commercial network consisting of pricing locations for the purchase and sale of electricity power and where market transactions can be settled by publically available Locational Marginal Prices (LMP's). In the ANEM model, these pricing locations were assumed to coincide with the set of transmission grid nodes and the LMP's were determined as part of the direct current optimal power flow (DC OPF) solution employed in the model. Furthermore, within the grid structure outlined in Appendix B, there are generation only nodes such as Bayswater, albeit located close to major load centres. However, in principal, nodes with low load factors can be accommodated in this framework and price and quantity data derived to assist in cost and benefit analysis underpinning RIT-T type assessments. This would help address the problems identified above that were related to the second and third sources of maladaptation to climate change.

Another factor that could help alleviate the points raised above was if a project proponent that was required to construct and fund significant transmission infrastructure as part of the project could earn revenue from this infrastructure linked to the provision of network services that help AEMO meet its own reliability and security standards. An advantage of this approach would be to potentially move away from the primary focus on least cost options to other types of transmission technologies that are intrinsically more expensive but also provide enhanced stability and reliability control solutions, for example. This might include FACTS or High Voltage Direct Current (HVDC) devices and systems that can give a greater degree of control over real and reactive power, frequency and voltage than is possible with lower cost but standard AC based systems and devices.

In this context, some augmentation of the structure of the ancillary service markets for frequency control and network control services might be required. This follows because currently these markets are linked to the supply of ramping capability and reactive power by generators to support both frequency and voltage as required. However, many FACTS or HVDC devices can achieve the same effects though a combination of control processes that regulate the output of connected generation. This type of control procedure would employ automatic feedback protocols that react to correct potential faults or deviations from frequency or voltage standards in a real time setting as they arise and would fall outside the scope of the ancillary service markets as currently structured.

More generally, given the different focus of public policy goals related to investment in renewable generation in combating climate change, and the inter-generational benefits associated with this policy objective, there is a strong public finance argument for government to fund investment in infrastructure to facilitate this policy goal through debt financing. In this case, because the benefits of combating climate change are spread out over time and possibly over generations, debt financing would allow future generations who benefit from actions taken now to combat climate change to contribute to the cost of public infrastructure built currently to support this policy objective. Clearly, investment in transmission capacity linking renewable energy to load centres would be a strong candidate for such support and funding.

7.7 Conclusion

In conclusion, we offer the following recommendations:

We encourage further investigation of the NEMLink proposal but with added scoping in relation to the ease of access of other potential regions containing renewable energy projects or resources including the Otway Basin, Broken Hill, Upper North South Australia and the Glen Innes area of New South Wales.
The route of the NEMLink proposal was developed with a particular eye towards the location of existing windfarms located particularly in the regional Victorian and mid North South Australian nodes as well as future potential gas-fired generation developments using CSG in the Surat Basin in Queensland. Given that the key policy goal of the NEMLink proposal was to open up potential sources of new generation in the NEM, the other areas mentioned in the recommendation have been identified as areas containing significant renewable energy potential including wind, solar and geo-thermal. These areas are the subject of future potential development and the existing transmission capability as well as the current configuration of the NEMlink proposal would not be sufficient to support significant levels of renewable energy developments in these regions.

An additional reason for including the scoping of the MurrayLink-Regional Victoria-Tumut (e.g Buronga-Darlington Point-Wagga Wagga transmission path) is that this transmission corridor would allow for power transfers from South Australia into both Victoria and New South Wales. This would assist in system balancing the impact of large penetrations of wind generation within the NEM by promoting the possibility of inter-state transfers of excessive wind power over a greater geographical region than is currently available or possible within the NEMLink proposal as currently configured.

- As part of this, investigate the feasibility of upgrading Darlington Point-Buronga-Red Cliffs 220kV transmission line to a 330 kV line with appropriate voltage support infrastructure. This would allow for greater transfer capability from the Tumut and Broken Hill areas of New South Wales to Victoria and also provide a parallel transmission path to the proposed Victoria-New South Wales part of the NEMLink proposal.

- Investigate the feasibility to up-grade or augment the current 220 kV transmission line connecting Red Cliffs to the NEMLink proposal either near Horsham or Bendigo to a 330kV or 500 kV transmission line. This would allow the secondary corridor linking Regional Victoria, Riverlands (South Australia) and Tumut (New South Wales) to connect to the main NEMLink transmission path.

- Investigate the feasibility to upgrade the Red Cliffs to Riverlands transmission branch to a 275 kV or 330 kV transmission line with appropriate voltage support infrastructure. This would entail upgrades or augmentation to Murraylink; to the Red Cliffs to Murraylink terminal station in Victoria; and to the Robertstown-Monash-Murraylink terminal station in South Australia. It would also provide a parallel path to the proposed NEMLink transmission path linking South Australia and Victoria. Importantly, it would also allow the export of excess wind power from mid north South Australia or regional Victoria directly into New South Wales via the Red-Cliffs-Buronga interconnector (e.g. line 37).

- Investigate the adequacy of access and capacity of both the existing 330 kV network and also the 500 kV network proposed in the NEMLink proposal for wind farm proposals located in the Glen Innes area of New South Wales.

- Feasibility considerations should be crucially linked to considerations of meeting policy goals of combating climate change by opening up access for renewable energy projects and resources as well as aiding system balancing within the NEM through adequate inter-state transfer capabilities for high penetration rates of intermittent forms of renewable generation.

- Given the link to policy aimed at combating the adverse effects of climate change, assessment should take place outside of the current RIT-T procedures and the funding should be met by the Commonwealth government through debt financing so that future generations who benefit from combating the adverse consequences of climate change can meet some of the costs of infrastructure built to achieve this policy objective.

- Investigate ways that the ancillary service markets for frequency control and network support services could be augmented to enable transmission infrastructure built by generation project proponents to earn revenue if this transmission infrastructure directly contributes to network reliability and security standards by supporting frequency and voltage levels of the electricity grid.

8. THE EFFECTS OF CHANGES IN WATER AVAILABILITY ON ELECTRICITY DEMAND-SUPPLY

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8.1 Introduction

The effect of changes in water availability on electricity demand-supply is presented in this chapter. Section 8.2 provides a literature review to inform the original research in the subsequent sections.

8.2 The relationship between climate change, water availability and the electricity sector

This section provides an overview of the relationship between climate change and electricity sector, particularly in terms of its demand and supply options. It also discusses the relationship between water and the electricity sector.

8.2.1 Climate change and electricity demand: nature of impacts

In January 2009, high temperatures over consecutive days in Victoria increased the demand for air-conditioning. This had put pressure on some part of transmission networks, requiring load shedding to maintain supply reliability and system-wide security (O'Keefe, 2009). Over the past two decades or so, growth in peak electricity demand in most of the NEM states has exceeded the growth in average annual demand (this situation has been particularly noticeable in South Australia). Peak demand only occurs a few times during the year on extremely hot summer days when air conditioners are being run in households in addition to other appliances, while the commercial and industrial sectors are concurrently consuming power. As climate change induced temperature rises are expected to become more intense in the future, there is likely to be more temperature-driven (or heat-waves driven) peak electricity demand. This obviously has the potential to compromise system reliability.

The uses of electricity directly linked to climate conditions are space heating and air conditioning. Literature suggests that in most countries higher temperatures are expected to raise electricity demand (for cooling) during the summer season and decrease demand (for heating) during the winter season (Benestad 2008; De Cian, Lanzi & Roson 2007; Mansur, Mendelsohn & Morrison 2008). The schematic of this relationship between electricity demand and temperature is shown in Figure 4-2 of Chapter 4.

Benestad (2008) undertook a study to investigate the pattern of changes in electricity demand in European countries. The study found that electricity demand related to heating requirements for the European countries may decrease as the number of days that the temperature is below the average (i.e., heating degree days) would become less frequent due to climate change. In contrast, the demand for electricity associated with the use of air-conditioners could increase as the number of days that the temperature is above the average (i.e., cooling degree days) would become more frequent.

De Cian et al. (2007) investigate the pattern of changes in electricity consumption as a result of variations in temperature, by using data from 31 selected countries across the OECD countries. Their findings are consistent with Benestad (2008). That is, a higher temperature would lead to higher electricity consumption during summer in countries with warm weather, while it would lead to lower consumption during winter in colder countries. Other studies (for example, (Mansur, Mendelsohn & Morrison 2008), (Eskelund & Mideksa 2009) also show similar results.

It is generally accepted that the impacts of climate change on electricity demand (particularly for heating and cooling purposes) are broadly consistent across countries, and are as shown in Figure 4-2. However, the relative importance (or magnitude) of these impacts differs across regions depending on the regional variations in temperature. There has however been little research analysing the demand-side impacts from a regional point of view, including for Australia. This is particularly important for Australia, given that approximately 40% of residential electricity is used for space heating and cooling (Sandu, Suwin & Petchey 2009). In addition, the demand for cooling has been increasing at more than 8% per year over the past 20 years, and this rate is expected to continue into the future.

8.2.2 Climate change and electricity supply: nature of impacts

The increased electricity demand driven by the heatwave that stuck Victoria in January 2009 also stretched the supply system to its limits. As noted earlier, the frequency of such events is likely to increase in the future. This raises a crucial question: will the NEM electricity infrastructure be able to cope with this type of threat in the years to come?

In order to improve the level of resilience of the NEM power system by adequately adapting to the ongoing climate change, information about the impacts of climate change on electricity system is required. This information will be useful to formulate and evaluate options and strategies for adaptation - an aspect that becomes particularly relevant in view of the long lifetime of electricity supply infrastructure as well as large investments required to build it.

The impacts of climate change on electricity supply come from three sources. First, the impact due to changes in the shape of load duration curve (also known as a daily demand pattern). For example, high-temperature-induced peak electricity demand can put great pressure on supply capacity, such as that occurred in Victoria during January 2009. As is well-known that electricity cannot be stored (in substantial quantities, without considerable cost) and must be produced instantaneously when it is required. A sudden change in demand pattern could have a direct influence on supply. For example, some technologies may have to reduce electricity production, while other technologies may be able to increase it. The exact impact will of course depend on the technical characteristics of the technologies, energy resource endowments of the regions, and the ability to trade electricity within the region.

The second source of impact concerns the technical efficiency of converting fuels into electricity in thermal power stations. Generally, the efficiency of such technologies depends upon the temperature differentials between the turbines and the external environment; the higher the temperature differential, the higher is the efficiency rating. As climate change is likely to result in higher temperatures, the heat differentials will decrease and thus reduce efficiency levels (Mideksa & Kallbekken 2010). However, this impact is likely to flow-through from changes in the availability of water for cooling purposes. This type of impact is discussed in more detail in Section 8.2.3.2.

Another source of impact stems from the geographical location of power plants (particularly of renewable energy plants) in a climate change prone area (Mideksa & Kallbekken 2010). Changing wind speed and patterns as a result of climate change, for example, can have an impact on wind generation output. Because the energy content of wind is strongly related to wind speed, relatively small changes to wind patterns can have very large effects on electricity produced from wind. Also, changes in solar radiation can affect the efficiency of photovoltaic system and could reduce the potential for solar energy generation. This source of impact however varies across areas as it involves different changes to the climate patterns for different locations. The climate change induced weather patterns for a specific location are often difficult to predict with certainty, and thus the impacts can only be analysed on a case-by-case basis.

8.2.3 Climate, water and electricity linkages

In a dry country such as Australia, water is one of the most valuable resources. In the electricity sector, it is required in large quantities in various types of power plants.

With the exception of the last two years, Australia has faced water resource challenges where precipitation, run-off, and stream flows had dropped to levels well below long-term averages (Preston & Jones 2006). Water storage levels in reservoirs were also consistently below capacity.

In 2007, several power plants had faced with the issue of water shortages caused by a hot and dry summer. This had resulted in electricity generation shut-offs in many states within the NEM region, causing electricity price hikes. According to climate change projections (see Section 8.3.4 for example), the frequency of such periods is likely to increase in the coming years. Therefore, it is important to analyse the effects of water resource on electricity demand and supply.

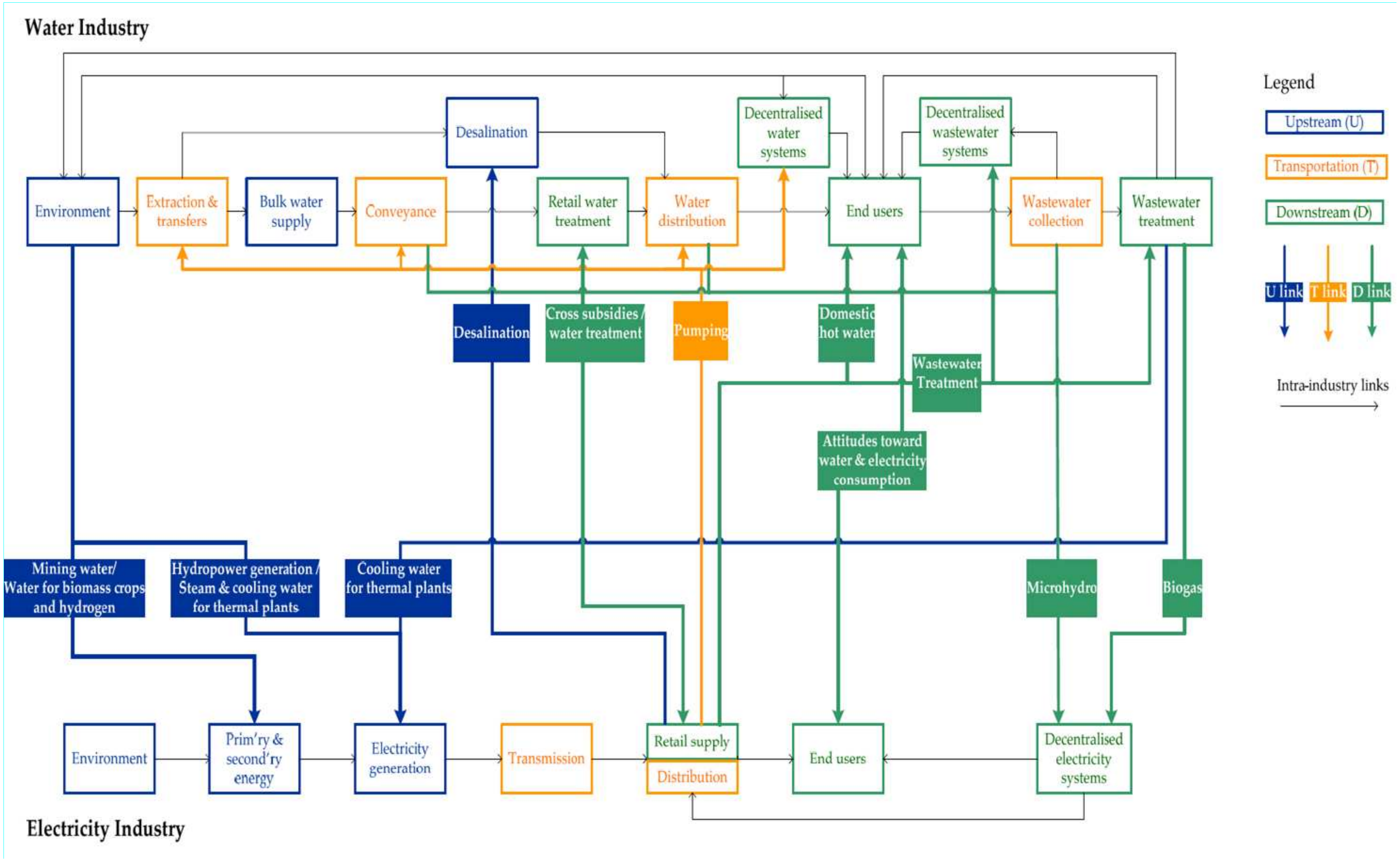
Apart from hydro power plants where water is used as in-stream to produce electricity, about 65% of electricity generation capacity in the NEM depends on freshwater for cooling purposes (Smart & Aspinall 2009). As a measure to mitigate greenhouse-gas emissions, significant amount of future electricity is expected to come from renewable energy, including solar and geo-thermal. These power plants, particularly those located inland, will also require water for generation and cooling. Drought-induced water scarcity and lack of water supply will affect such infrastructure. A lack of water supply for cooling purposes, for example, will negatively affect electricity generation in power plants.

Marsh (2008) and Smart & Aspinall (2009) provide a comprehensive review on the relationship between water and electricity. Water and electricity are inextricably linked. Electricity generation requires water for optimal operation, while water treatment and transport uses electricity. These links encompass various functions in both water and electricity industries. Figure 8-1 shows major physical and institutional links across the three functions – upstream, transportation and downstream – of both industries.

At the upstream and transportation levels, the water-electricity links are mainly physical. At the upstream level, for example, electricity is used for seawater desalination, and water for electricity generation. While the former shows the impact of water on electricity demand, the latter reflects the effect of water on electricity supply. At the transportation level, there is mainly a one-way link, namely, electricity used for groundwater extraction, surface water transfers, and for retail water businesses. The transmission and distribution of electricity consume negligible amounts of water.

At the downstream level, water-electricity links can be physical or institutional. For example, electricity is used for water and wastewater treatment, while water is used in decentralised electricity generation systems. There is also the link through cross subsidisation of both, particularly through the arrangements of concessions among multiple infrastructure services. The pricing policies, such as full cost recovery and volumetric pricing, can also influence consumption of both resources by the end users.

Figure 8-1 Linkages between water and electricity industries



(Source: Marsh 2008)

8.2.3.1 *Water and electricity demand*

The effect of changes in water availability on electricity demand is largely indirect – the use of electricity for water infrastructure. That is, the use of electricity for the provision of water services. The electricity use for water infrastructure has been examined by several authors from the perspective of climate change. Aside from water systems being vulnerable to climate change, water systems contribute to climate change issues through the use of electricity generated from fossil fuels (Flower, Mitchell & Codner 2007).

The water supply-use-disposal chain consumes electricity at each stage: extraction, conveyance, treatment, distribution, end-use, wastewater collection and treatment (Cohen, Nelson & Wolff 2004). Water-electricity links identified by Marsh (2008) include electricity used for bulk water supply such as seawater desalination, pumping associated with groundwater extraction and water conveyance, electricity required for retail water treatment, pumping for water distribution, end use electricity demands for hot water and water appliances and electricity used for wastewater treatment. The amount of electricity used for these services depends on regional contexts such as local topography and distance to water abstraction and discharge location, quality of raw water, treatment technology and environmental and health requirements (Kenway et al. 2008).

In Australia, most of the freshwater needs come from surface water. Large-scale dams were built to store water in order to maintain the security of water supply. Drought-triggered water shortages over the past decade jeopardised this supply security. As such, seawater desalination appears as an alternative source of maintaining water security. Currently there are desalination plants in operation in Western Australia and South Australia. Additional desalination plants are being built in the NEM region, including in New South Wales, Victoria and Queensland. Seawater desalination is extremely energy-intensive and consumes more electricity than other water supply options (Table 8-1). This could pose a maladaptation issue as these projects will lead to increased emissions. For example, the operation of Wonthaggi Plant in Melbourne could produce almost a million tonnes of CO_2 each year (Mitchell 2008).

Table 8-1 Electricity consumption by various water sources

Water source	Electricity consumption (kWh/kL)
Conventional water treatment	0.1 – 0.6
Conventional wastewater treatment	0.4 – 0.5
Groundwater desalination	0.7 – 1.2
Advanced wastewater treatment	0.8 – 1.5
Seawater desalination	3.0 – 5.0

(Source: Marsh 2008)

Climate change, and associated drought, is likely to increase the reliance on groundwater as surface water become scarce. Extracting groundwater is however energy-intensive, particularly if groundwater extraction is deeper underground requiring more energy for pumping per unit of volume of water. In NEM states, surface water is typically cheaper than groundwater as surface water sources are more abundant. However, drought over the past years has led surface water prices to exceed groundwater prices. This switch towards extracting cheaper but energy-intensive groundwater is therefore likely to increase electricity consumption.

For local water supplies that are insufficient to meet demand, surface water can be transported from regional areas. While the surface water is generally cheap, it is relatively expensive to transport across long distances. In New South Wales, water transfers from Shoalhaven and Kangaroo Rivers in the south of the state augment supplies for greater Sydney during drought. Over the past few years, about 28% of Sydney's water supplies have come from these areas. These transfers would have increased the electricity consumed by the water industry.

Apart from surface and groundwater sources, water and wastewater treatment can supplement further supplies. The treatment processes use a range of technologies that consume electricity to varying degrees. The choice of technology is dependent on several factors, including the quality of water entering the water treatment plants, policies controlling the discharge quality of treated effluent, intended reuse of treated effluent, and cost implications. Most of the water treatment infrastructure today comprises large-scale centralised systems, but more decentralised systems are increasingly being considered. Because of this multitude of technological options involved, it is possible that a decentralised water system consumes more electricity than the centralised system it intends to replace. For example, some decentralised water treatment processes consume electricity up to 47 kWh for each 1 kL of water treated (Holt & James 2006). This is far higher than compared with other sources of water supply (Table 8-1). In addition, more advanced wastewater treatment consumes significantly more electricity compared with conventional water and wastewater treatment (Table 8-1). In order to meet increases in water demand or to drought- proof water supplies, increasing the use of recycled water would therefore significantly increase electricity demand.

8.2.3.2 Water and electricity supply

Electricity production is dependent on many climate variables, depending on technical characteristics (for thermal-based electricity) and geographical location of power plants (for non-thermal electricity such as wind and hydro) (Mideksa & Kallbekken 2010). For example, temperature and precipitation can affect the availability of thermal-power and hydro-power plants; changes in wind speed and direction can affect wind power plant availability, and changes in the intensity of solar radiation can affect solar power plant availability.

Unlike the effect on electricity demand, changes in water availability can have direct implications on electricity generation – the use of water for energy infrastructure (that is for electricity generation). Water is used during the process of electricity generation as cooling water in thermal power stations and as a source of energy for hydropower. The effect of changes in water availability could therefore be substantial in regions where there is dependence on water supplies for hydropower generation and/or for cooling in thermal power plants.

Decreased availability of fresh water can have serious implications for many parts of the energy sector that depend on water. In mid-2007, for example, both thermal and hydro power stations in Australia faced serious threats to electricity generation capacity as a result of long-standing drought that afflicted much of the south-east regions. The consequences were immense. There were reductions in generation at Queensland's two major power stations (Swanbank and Tarong), which caused job losses in upstream industries and lost government revenue. Further, salinity in water storages that supply to power stations increased to dangerous levels as a result of disruption in water flows. Power station owners were required to install expensive salinity control devices to protect power station equipment from damage.

Climate change induces direct as well as indirect impacts. The direct impacts of climate change on the electricity sector, including supply infrastructure, is obvious and this is discussed in more detailed in Section 8.2.2. For indirect impacts, the study by Rübbelke and Vögele (2011) has shown that drought-induced water scarcity and lack in water supply could also affect infrastructure beyond the electricity sector. Water is one of the important inputs for electricity production, and vice versa (Marsh 2008). As such, the adaptation response has to be placed on both electricity as well upstream water supply sectors. As water becomes less available for producing electricity from both thermal and non-thermal power plants, there is a possibility that climate change may increase the cost of providing water infrastructure. Various studies have shown that the cost of adapting water infrastructure could be significant, which might undermine the effectiveness of adaptation response (EEA 2007; Ludwig et al. 2009).

8.2.3.3 Thermal-electricity generation

Water has many different uses in thermal electricity generation, including in the boiler for steam-raising, in the cooling system, for managing and disposing ash, and for services and potable water supplies (Smart & Aspinall 2009). The majority of water gets evaporated during the cooling process.

Thermal power stations need access to secure and reliable water supplies so that they can provide security of supply to electricity consumers and meet system reliability requirements. The resilience of power plants to climate change adaptation is therefore dependent on the availability of secure water supplies. Water insecurity can lead to a reduction in electricity output. For example, Linnerud et al. (2009) has shown that a 1˚C increase in temperature would result in thermal efficiency loss due to decrease in the availability of cooling water. This could reduce electricity output from fossil-based power plants by 0.6% and nuclear power plants by 0.8%. While the impact is small in percentage terms, the overall effect on NEM could be substantial given that the majority of power plants in the NEM are based on fossil fuel.

Coal-fired power stations represent the majority of thermal power stations in Australia. Most of these are traditional sub-critical types, with efficiencies of around 35%. Several types of cooling processes are employed in these plants, including once-through cooling (Eraring and Liddell power stations), natural draft closed cooling (Bayswater, Stanwell, Mount Piper and Loy Yang A and B power stations) and forced draft closed cooling (Swanbank power station). More recently a number of super-critical coal plants (with efficiency generally exceeding 40%) have been constructed in Queensland, including Tarong North, Millmerran, Kogan Creek and Callide C power stations. Millmerran and Kogan Creek are based on dry cooling process.

Over the last decade, a number of combined-cycle gas turbine power stations have been built in Australia, including Pelican point and Newport (direct cooling), Swanbank E and Townsville (closed-forced cooling), and Osborne (recirculated direct cooling). This electricity generation technology generally has lower water consumption compared with coal-fired technology (Table 8-2). Open-cycle gas turbine uses very little water, but also has lower efficiency rating as well as higher carbon intensity than combined-cycle technology.

Another thermal electricity generation technology that has received increasing attention is integrated gasification combined cycle (IGCC), also known as 'clean coal' technology. The major benefit of this technology is its improved efficiency rating, as well as reduced water consumption (Table 8-2). Marsh (2008) also noted that nuclear power (though not currently used in NEM) would consume 30-50% more water than coal fired power.

Table 8-2 Physical characteristics of thermal power stations

Generation technology	Cooling system	Water use (ML/GWh)	Efficiency (%)	CO_2 intensity (tonnes/GWh)
Black CF (sub-critical)	once-through	2.0	36	884
Black CF (sub-critical)	recirculating	2.2	36	890
Black CF (sub-critical)	dry-cooling	0.3	34	936
Black CF (super-critical)	once-through	1.8	42	750
Black CF (super-critical)	recirculating	2.0	42	758
Black CF (super-critical)	dry-cooling	0.3	40	796
Black CF with CCS (super-critical)	recirculating	2.7	40	51
Black CF with CCS (super-critical)	dry-cooling	1.0	38	55
OCGT	-	0.001	36	513
CCGT	once-through	0.58–0.68	52	355
CCGT	recirculating	0.88	52	355
CCGT	dry-cooling	0.08	50	363
CCGT with CCS	recirculating	1.02	50	25
CCGT with CCS	dry-cooling	0.28	48	28
IGCC (coal)	-	1.2	40-45	700–800
Nuclear (steam)	once-through	2.3–2.8	na	na
Solar thermal	-	3.60	na	na
Solar PV	-	0.11	na	na
Wind	-	0.004	na	na

(Sources: Smart & Aspinall 2009; Marsh 2008)

Notes: CF – coal fired, CCS – carbon capture and storage, OCGT – open cycle gas turbine, CCGT – combined cycle gas turbine, IGCC – integrated gasification combined cycle,

As a measure to mitigate greenhouse-gas emissions, significant amount of future electricity is expected to come from renewable energy, including solar-thermal and geo-thermal. Technically, both technologies are similar to coal-fired and gas-fired steam turbine plants. While coal-fired and gas-fired power plants use coal and gas respectively as fuel inputs, solar-thermal and geo-thermal power plants use sunlight and dry-hot-rocks from deep underground as energy sources in similar technology (thermal steam turbine) to produce electricity. Due to lower energy content in sun and hot rocks, they are likely to operate at lower thermal efficiencies than conventional fossil-fuel-fired power stations. So the heat load that must be rejected to condense will be higher. As a result they are likely to have higher water intensity.

Another important issue to consider for the use of both solar-thermal and geo-thermal technologies is their location. In Australia, it is likely that most of these technologies will be located inland where it is drier and hotter. In those areas, the availability of water is already an issue even without the effect of climate change.

Carbon capture and storage for thermal power stations has been given considerable support in Australia in order to mitigate climate change while utilising abundant coal resources. There are a number of current projects in the pipeline in Australia. The implications of this technology for water use are worth noticing (see Table 8-2).

Hydro-electricity generation

Hydro-electric power stations are the largest users of water of all power stations in Australia, accounting for around 99% of total water use in the electricity industry. Currently, hydro- power plants represent approximately 14% (7.6 GW) of the total electric installed capacity in Australia, and contributed to around 6% (13 TWh) of the total gross electricity. Using the installed capacity and the gross energy converted, it is possible to calculate the average capacity factor, which shows the ratio of the availability of the resource. The capacity factor for hydro-electricity is approximately 21%. This ratio was more than 30% in 2000.

We can broadly say that water is used rather than consumed for hydro-electricity generation, as the same water is available for downstream users.

Unlike the effect on thermal-power plants, climate change can have either positive or negative impacts on hydro-electricity generation, depending on whether it resulted in increases or decreases in precipitation and river flow. This is a region specific phenomenon. Similar to hydropower, electricity production from other non-thermal sources such as wind and solar differ by region. For example, the area where wind speed increases as a result of climate change the efficiency of wind power is likely to increase, whereas areas with decreasing wind speed would have less wind power potential. All studies of such impacts reviewed by Mideksa and Kallbekken (2010) focused on Europe and the US.

Hydro power depends on the seasonal cycles of water that provide rain and snow, and the runoff from snow packs. The hydrological resource has more representative variations in timescales from day to year, but hourly variations can be very important if the applied technology does not have water storage capacity (dam). The two most important harnessing modes from the hydro resource are run-of-river and dams. Variations in the water cycle determine water availability and thus total potential energy that can be stored. Despite storage capacity, dams are still susceptible to seasonal variations (e.g, from wet periods to dry ones). On the other hand, run-of-river systems are more susceptible to variations in the water cycle than dams because water level and flow in the river dictate the available energy and, in general, no storage is available to counterbalance the fluctuations of the resource. Drought periods are one of the major problems related to the dynamics of the hydro resource, especially when they coincide with periods of high electricity demand.

Australia's major hydro-electric power stations are in the New South Wales Snowy Mountains, and throughout Tasmania. There are many smaller schemes such as the Kiewa Scheme, the Ord River Hydro plant, and schemes associated with water storages and dams such as Wivenhoe Dam in SEQ, Dartmouth Dam in Victoria and the Kangaroo Valley and Bandeela schemes in New South Wales.

As power stations are often located in rural areas, water used by these power stations is usually shared and or reused by irrigators and for aquatic ecosystems (Marsh 2008). Release of water in hydro-electric schemes is thus in many cases determined by factors other than electricity generation, such as in the Snowy Scheme where water for irrigation is the main determinant of release. In other cases, such as in Tasmania and in smaller schemes such as the Warragamba and Fitzroy Falls, the generation of power is the prime criteria for release (Smart and Aspinall 2009). Increasing water demand for these other uses has had an impact on water use arrangements for some hydro-electricity power stations. This includes the case where the Victorian and New South Wales Governments decided to return up to 212 GL in 2000 as environmental flows to the Snowy River.

8.2.3.4 Water allocation and access arrangements

Drought-induced water shortages in 2007 resulted in increased volatility in electricity prices (which more than doubled compared with the same period of the previous year) as well as government intervention in arrangements for supplying water to power generators. Water security, particularly the sustainable use of water resources and the introduction of CPRS and RET (as discussed in more detailed in Section 8.5.2) will be key challenges for private investors and operators in the electricity and water industries, as well as state and commonwealth planners and policy makers in the coming years.

As a result of power stations' shut-off that arose from water shortages, generators across the country have put in place contingency measures to secure their water supplies. Power stations in the La Trobe Valley of Victoria, for example, bought emergency water from an internet auction site to ensure their water supplies were sufficient to meet expected generation. In NSW, a generating company transferred generation from an inland station located in a region experiencing water shortages to a coastal power station cooled by seawater. Other generators in NSW have secured additional water from nearby coal mines, have installed equipment to treat effluent from a local wastewater treatment plant for onsite reuse, and have obtained permission to extract additional river water that is normally reserved for periods of high river flows (New South Wales Government 2007). In Queensland, the drought has initiated a large-scale centralised recycled water scheme – the Western Corridor Recycled Water project, which will be used in two major power stations, in addition to other uses. This would increase their generation cost.

Snowy Hydro, which operates Australia's Snowy Mountains Scheme near the border between Victoria and NSW, has also introduced a range of measures to reduce its exposure to water shortages. During the drought, the company commenced a winter cloud seeding program, in order to increase snowfall, thereby increasing water inflows into its water storages when the snow melts. The company also recycled water through its largest power station, Tumut 3. In order to further reduce its exposure to water shortages, Snowy Hydro has procured two gas-fired power stations in Melbourne, with the aim to use these power stations to supplement its hydropower generation during peak electricity demand when water storages are low. Generation from these two stations is controlled by an operating licence from the Victoria Environment Protection Agency (EPA), in order to limit carbon emissions. Given the severity of drought, the company has transferred generation to the gas-fired power stations above anticipated levels and has reached the limit set out in its EPA licence. At the same time, the EPA has reduced the operating hours of the two stations due to the complaints about vibration from nearby businesses.

The difficulty in the case of Snowy Hydro raises significant issues for electricity generators seeking to secure limited water supplies. Particularly, difficult trade-offs are likely to occur when there are insufficient volumes to meet the needs between electricity generators and other users. Climate change will have adverse impacts on water availability, and will lead to competition between different sectors (Hightower & Pierce 2008). Serious allocation problems may result from increased water scarcity: who gets to use how much of water, for which purpose, and at what time? Trade-offs will occur, and concerns will increasingly be raised over which use is more important: water for drinking, growing food, personal use or electricity production (Feeley et al. 2008). Water resources typically serve different purposes, with diverse values placed on their use. This inherent conflicts give rise to potential trade- offs, particularly during times of water shortages.

The Snowy Mountains Scheme offers insight into the types of trade-offs being experienced between the generators, irrigators and the environment. The Scheme diverts water for hydropower generation from the Snowy River and discharges it into the Murray and Murrumbidgee Rivers to serve farming interests west of the Dividing Ranges, as well as downstream users in Victoria and South Australia. Water allocations between users are generally defined under Snowy Hydro's water licence. Despite this agreement, irrigators often claimed that the Snowy Hydro placed their access to irrigation in jeopardy and impacted their farming.

Thermal power stations have also been engaged in water trade-offs with other users. In 2007, NSW imported cheap electricity from Queensland. At the time, the Queensland power stations were sourcing cooling water from Brisbane's main drinking water supply in Wivenhoe dam despite the imposition of water restrictions in the region, and despite sufficient generation capacity in NSW to meet its own demand.

This trend of trading water between generators and other users is likely to become more frequent and more severe with climate change. Under the National Water Initiative (NWI), the Council of Australian Government acknowledged that better management of water resources is a critical issue. It identifies that the way water is allocated attaches rights and responsibilities to water users. This right should be allocated based on the share of water that can be extracted at any particular time, while the responsibility is to use the water in accordance with usage conditions set by the authority. Currently, the access arrangements differ widely across the NEM region, and are a reflection of historical developments when both sectors were vertically integrated and largely government owned. This needs to be adjusted.

Surface water supply (the largest water source in Australia) is generally provided to inland generators under licence agreements between government-owned water authorities and government-owned generators. There are various mechanisms within this arrangement (Smart and Aspinall 2009), including special purpose licences such as major utilities licences in NSW, access entitlements providing a share of available capacity in the water system, specific purpose agreements such as the Snowy Water Agreement, and direct contracts with water authorities.

Water access arrangements for hydro-electricity generators vary across water users, depending on the provision for the release of water (Smart and Aspinall 2009). Some arrangements give priority to demand for irrigation; this includes the licence for Snowy Water and Ord River. Others give it to the generators, mainly in Tasmania.

Relatively new gas-fired power generators can access water through direct contracts with local water utilities, while the old ones (older than ten years) in South Australia and Tasmania can acquire saline water for cooling under licence with the respective state governments.

8.2.3.5 Flow-on effects of climate change impacts and maladaptation

The foregoing discussion suggests that the implications of reduced water availability for electricity supply are substantial. This includes loss of power generation due to water shortages, future investment decisions and impact on electricity prices. There is also a vicious cycle between water-electricity-climate links. Reduced water availability through river flow may create incentive to build energy-intensive desalination plants, which is likely to increase electricity demand and further tighten the supply-demand balance in the NEM. These two effects may create positive feedback by increasing greenhouse-gas emissions, thereby increasing the likelihood that further adaptation to climate change will be required in the future.

Drought-induced water scarcity and lack of water supply could also affect infrastructure beyond the electricity sector. Water is one of the important inputs for electricity production, and vice versa. As such, the adaptation response has to be placed on both electricity as well upstream water supply sectors. As water becomes less available for producing electricity, from both thermal and non-thermal power plants, there is a possibility that climate change may increase the cost of providing water infrastructure. The cost of adapting water infrastructure could be significant, which might undermine the effectiveness of adaptation response. Not only that, investment in water supply technologies will be required, the management of this upstream critical infrastructure will also need to be improved, as well as the governance arrangements that are compatible with the electricity sector will need to be established. In addition, the review in this section also showed that there is a lack of coordination between water and electricity industries, and also with the regulators and authorities.

8.3 Methodological framework

This section presents an overview of methodological framework employed in this research project. It starts with a summary review of methodologies, which would then be used to frame the modelling approach for conducting the analysis. In addition to the modelling, this section also describes scenarios for analysing the impacts of climate change on the electricity sector.

8.3.1 Review of methodologies

8.3.1.1 Impacts of climate change on electricity demand

There are only a few studies that empirically estimate the impacts of changes in temperature on electricity demand. Below are some such studies.

De Cian et al. (2007) employed a fairly straightforward dynamic panel data technique to estimate this relationship. The regressions were performed on the data for 31 countries across the world, for the period 1978-2000. In their model, residential electricity demand is dependent on its own lagged values, electricity prices, per capita GDP and temperature. The authors found that, for countries where average temperature is relatively high, the elasticity of electricity demand with respect to summer temperature is 1.17, and that with respect to winter temperature is 0.1. Similarly, for colder countries, the elasticities of electricity demand with respect to summer and winter temperatures are -0.21 and -0.07, respectively.

Lee and Chiu (2011) developed a dynamic non-linear model for forecasting electricity demand, which is a function of real income, electricity price and temperature. Based on data for 24 OECD countries for the period 1978-2004, the authors have shown that the use of constant elasticities for forecasting electricity demand is not reliable. That is, there is a strong non-linear relationship between electricity demand and other three independent variables. Relevant to this research, the authors found that there is a U-shaped relationship between electricity consumption and temperature. In other words, electricity consumption tends to decline when temperature increases during the winter season (i.e., when the average temperature is lower), while temperature increase during the summer season (i.e., when the average temperature is higher) tends to raise the demand for electricity. In addition, the authors also found that the impact of temperature on electricity demand is becoming more important in recent years. This was shown in the estimated elasticities of electricity demand with respect to temperature; the estimated elasticities were negative prior to 1987, became positive after 1988, and have steadily increased since then. All these results support the view that the model developed by the authors can capture the impacts of climate change on electricity demand, as reviewed in Section 8.2.1.

Thatcher (2007) used data for four Australian states operating within the NEM to describe a methodology for estimating electricity load duration curve at 30-minute interval. A large proportion of the variability in electricity demand is dependent on the weather. Thus, this level of detail should enable the analysis of the impacts of various climate change scenarios on electricity demand patterns. While the application of the method adopted by Thatcher (2007) can replicate the intraday electricity demand at a reasonably accurate level, the only variables it captures are the average daily temperatures and an index describing the type of weekday. That is, it does not capture changes in economic and demographic variables on electricity demand. The author also demonstrates the application of the model by estimating the changes in daily demand pattern (represented as load duration curve) due to a 1˚C increase in average temperatures for four Australian states. This example shows that the impact of changes in temperature on electricity demand is not universally consistent across Australian states. While the peak electricity demand is estimated to decline in NSW and VIC as a result of an increase in temperature, it may lead to increased demand in QLD and SA.

8.3.1.2 Impacts of climate change on electricity supply

Unlike the study on mitigating greenhouse-gas emissions from the electricity sector, the research that focuses on the impacts of climate change on electricity generation is scant. Below are some such studies, which have been classified into two approaches – optimisation and simulation.

One class of modelling approach is based on the reference-energy-system optimisation model. This approach is traditionally used for long-term scenario planning for the energy sector. It focuses on the flow of energy within the economy, from energy resource extraction, through to energy transformation, and end-uses. This approach is increasingly being used to assess the impacts of climate change adaptation. For example, Lucena et al. (2010) employed a long-term bottom-up optimisation model developed by the International Atomic Energy Agency (called Model for Energy Supply Strategy Alternatives and their General Environmental impact (MESSAGE)) to examine the least-cost adaptation measures for global climate change impacts on the electricity supply system of Brazil over the next 30 years. The authors note that this method has the advantage of finding optimal solutions that takes into consideration the interactions between energy demand and supply over the long-term planning horizon.

Reiter and Turton (2009) also employed multi-regional MARKAL model (an optimisation model developed by the International Energy Agency) to determine the impacts of climate change on the electricity sector of the European countries, and to quantify additional investments into the sector required to cope with the climate change. Specifically, the authors analysed the impact of higher temperature on the electricity generation sector for time horizons up to 2050.

Another class of modelling approach is agent-based electricity market simulation. This approach is often used to investigate the behaviour of multi-players within a liberalised electricity market. While the least-cost optimisation approach focuses on the solution that minimises the total cost for all suppliers in the market, the agent-based approach simulates the behaviour of the suppliers that try to maximise market share and profits. However, not many studies have employed this approach to analyse the impacts of climate change on electricity supply. Sichao et al. (2010) employed a multi-agent based model to simulate an emissions-free electricity market in Japan. They simulated the electricity supply mix under two conditions – prior to and after imposing an emissions cap – for a twenty-four hour operating period. The authors also compared their results with those based on the application of least-cost optimisation approach, and found that the results of the two methods were similar.

While The Integrated MARKAL-EFOM System (TIMES) model is essentially an energy sector model, it also allows the flow of water to be included within the model, and thus to assess the impacts of water availability on the electricity system. Cleto et al. (2008) demonstrate this by employing TIMES model to assess the impacts of changes in water availability on the Portuguese energy system. The model was optimised on the 2050 time horizon for three scenarios:

- reference,
- weak decrease in water availability, and
- strong decrease in water availability.

A review of the two approaches for analysing the impacts on electricity supply (above) suggests that while an optimisation approach is well suited to assess the long-term impacts on the electricity sector, it cannot adequately capture the short-term dynamics of electricity supply-demand interactions. In contrast, a simulation approach is well suited to assess the short-term behaviour of the market agents, but cannot be used to assess the optimal changes within the electricity system over the long-term.

Recently, Pina et al. (2011) have demonstrated how the optimisation approach can be applied to analyse short-term electricity dynamics. They applied an extension of the TIMES model for analysing investment decisions in electricity production, by considering seasonal, daily and hourly supply and demand dynamics. The TIMES model is traditionally used for long-term planning. Pina et al. (2011) therefore suggest that the short-term dynamics of the electricity system can also be captured. For example, demand for electricity varies during the day (daily load curve), and between different seasons (summer/winter). Any change in climate patterns and/or policy incentives has the potential to alter the shape of electricity demand. On the supply-side, electricity generated from renewable sources also varies for different periods (during the day and between seasons). That is, the capacity utilisation rates for solar, wind and hydro, for example, are not constant throughout the day. While capturing these short-term dynamics, the model does not lose sight of the need to provide an optimal mix of technologies and fuels for meeting electricity needs over the long-term under specified technical, economic and weather-related constraints.

8.3.1.3 Impacts of climate change on water availability

Climate is a fundamental driver of the water cycle, which determines how much water is available for various uses including for the electricity sector. There are some studies that attempted to understand how climate change affects water supply. However, most of these studies (Koch & Vögele 2009; Otero et al. 2011; Post et al. 2012; Xiong et al. 2010) focused on an application of complex hydrological modelling where detailed meteorological and water system information for a specific region are available. A brief review of selected studies is shown below.

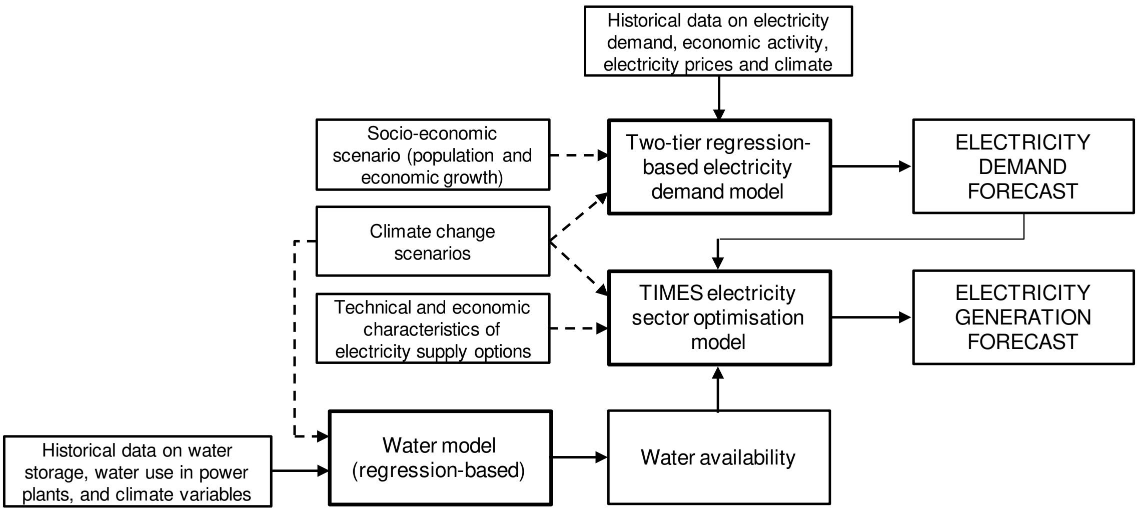
The study by Koch and Vögele (2009) has shown how to integrate the mathematical function for the calculation of water demand for power plants. Although this is typically included into a water resources management model, it can easily be implemented as part of the electricity system optimisation model. This integration allows capturing the effects of climate change on water demand, which can then be used as an input variable in the electricity supply model.

Post et al. (2012) employed a multi-modelling platform to assess the current and future water availability for Tasmania. Their suites of models include rainfall-runoff modelling, water recharge modelling, groundwater modelling, and river system modelling. This study showed that a 3% reduction in rainfall in Tasmania in 2030 would lead to a reduction in surface water availability of 5%.

8.3.2 Modelling approach

Based on the review above, Figure 8-2 shows the overall modelling framework that is employed in this research project for quantifying the impacts of climate change, and associated changes in water availability, on electricity demand and supply. The framework consists of three main models – electricity demand model, water model, and electricity supply model. These models (as shown in bold boxes in Figure 8-2) are discussed below.

Figure 8-2 Overall methodological framework



8.3.2.1 Electricity demand model

The regression models are developed from historical data on electricity demand, economic activity, electricity prices and weather-related data for five Australian states in the NEM region.

These regression models are developed based on a two-tier estimation procedure by taking into account the robustness in electricity demand forecast. This includes long-term demand forecast which is essentially used to determine future investment needed to ensure reliable electricity supply in the longer run, and a short-term demand forecast which is essentially used to determine daily variability in load duration curve. This two-stage procedure allows the impacts of climate change on electricity demand to be analysed in a more robust manner. That is, it can capture both short-term demand responses from daily temperature fluctuation, as well as changes in demand pattern caused by shifts in temperature trends, along with other economic and demographic factors.

In the first stage, the long-term electricity demand forecasting model is estimated based on the method proposed by Lee and Chiu (2011). This model builds the long-term trends in temperature (along with other economic-demographic variables) dependence of annual electricity demand.

The model is defined as follows:

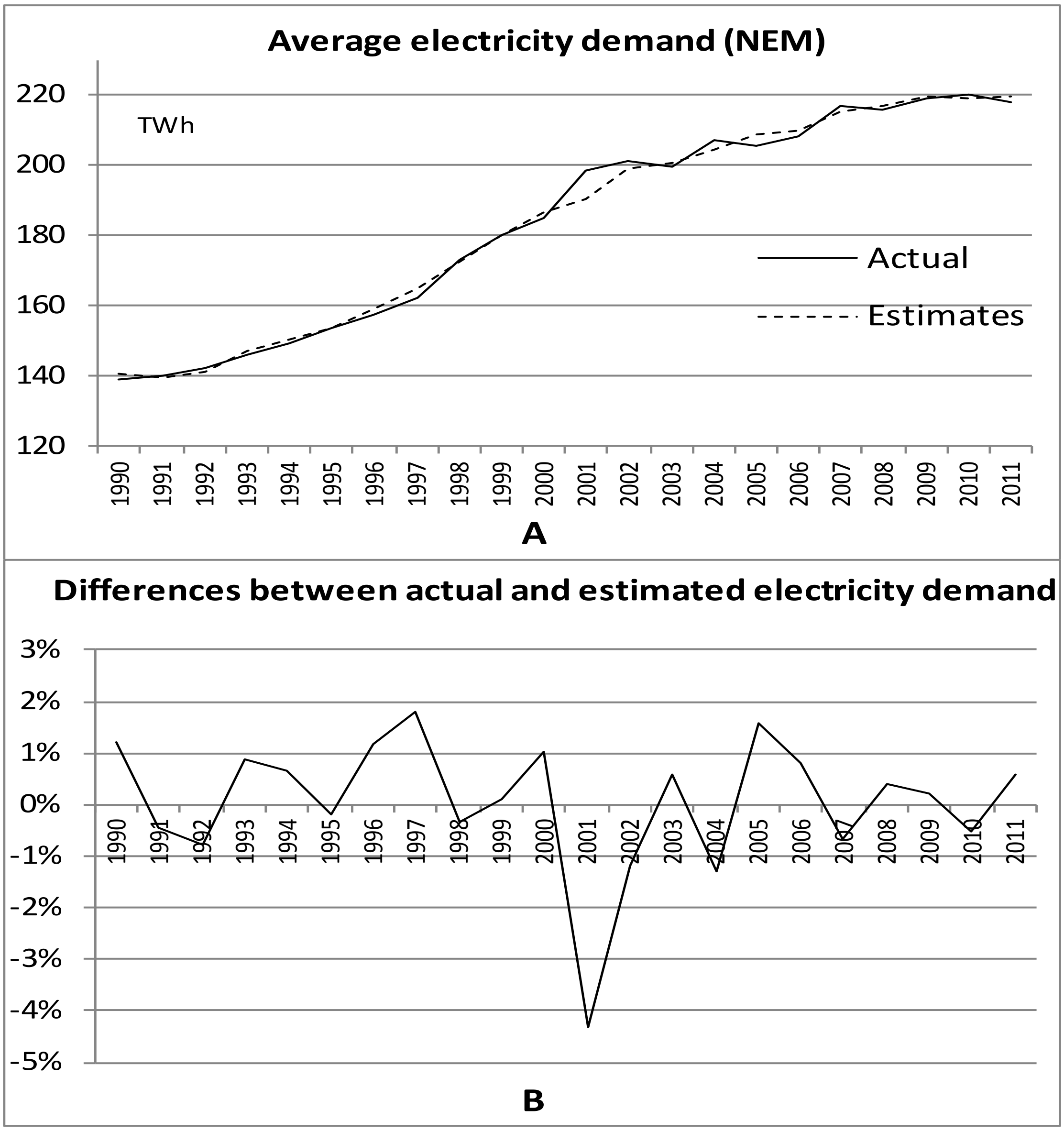
$$LnE_{st} = a + b.LnPOP_{st} + c.LnY_{st} + d.LnP_{st-1} + e.LnT_{max_{st}} + f.LnT_{min_{st}} + \varepsilon_{st}$$

Where E = electricity consumption
POP = population
Y = real gross state products
P = real electricity price
T_{max} = maximum temperature
T_{min} = minimum temperature
ε = error-term
s = state
t = year
Ln = (natural) log-transformed function

Equation (8-1)

Equation (8-1) is used to calibrate the annual electricity demand for all five NEM states using historical data covering the period 1990-2011. The result of this calibration can be used to assess the performance of the model, by comparing with the observed (or actual) electricity consumption. This comparison is shown in Figure 8-3 (also refer toTable 8-3 for summary statistics for each State). It is clear from Figure 8-3 that the model reasonably tracks actual consumption, with the error (calculated using root-mean-square, as shown in Figure 8-3B) within the range of around ±1%, with the exception for 2001 where the largest growth (8%) in NEM's electricity consumption is observed. This implies that under the normal rate of change in economy, demography and temperature variables the model has the potential to project demand with reasonable accuracy.

Figure 8-3 Comparison between actual and estimated annual electricity demand for NEM



At the state-level, the model is also capable of capturing demand growth. It can best replicate the demand for NSW with the RMS error below 1%, while the highest error (2.83%) occurred for QLD (Table 8-3).

Table 8-3 Select summary statistics of the annual electricity demand models

Statistics	NSW	VIC	QLD	SA	TAS
Adjusted R^2	0.9954	0.9210	0.9608	0.9719	0.9493
Durbin-Watson stat	2.29	1.37	1.00	1.24	0.94
RMS percent error	0.83	2.67	2.83	2.40	2.32

In the second stage, the changing temperature during the diurnal cycle is used to formulate the intraday variability in electricity demand. This second-stage procedure allows the analysis of climate change on electricity demand, which can then be used to analyse the impacts on electricity supply with more detailed resolution.

In light of the review above as well as the test conducted for different approaches (such as, nonlinear model and dynamic regression model), this study developed an hour-by-hour electricity demand model as it provides estimates that reasonably fit the historical hourly demand data. Thus the model comprises of a 24 equation set, each representing each hour of the day. The model is defined as follows:

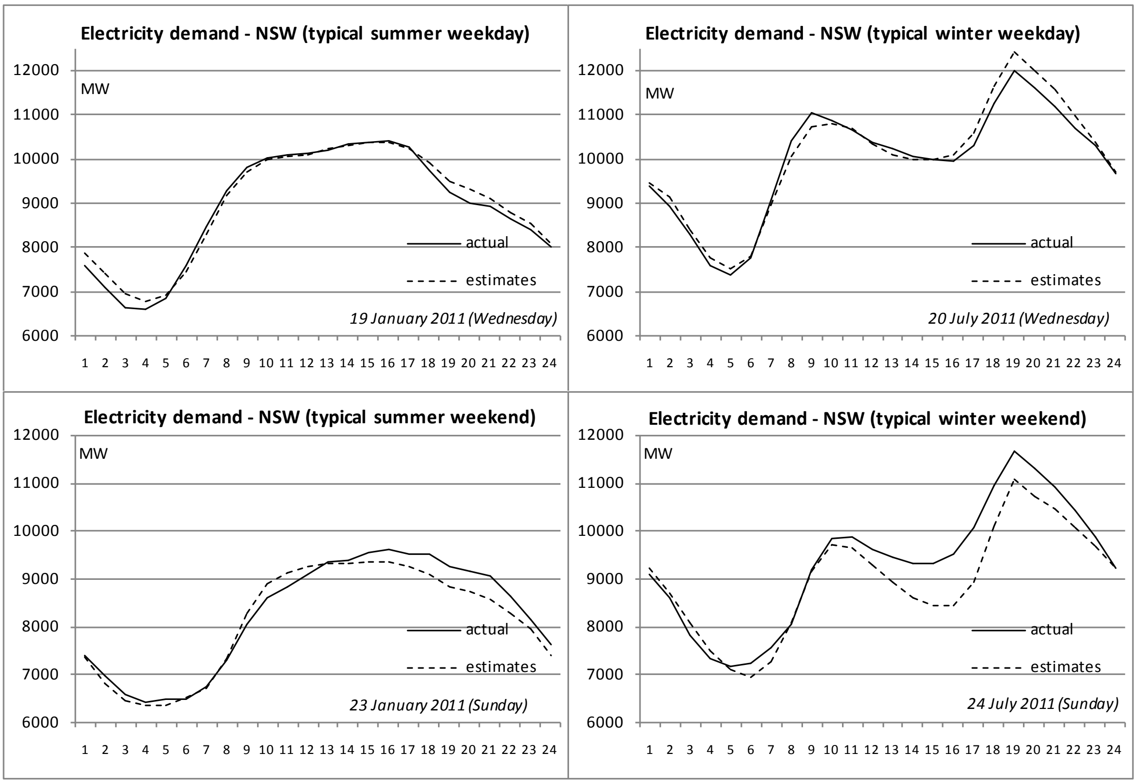
$$E_{sh} = a + b.T_{max_{sh}} + c.T_{min_{sh}} + b.M + c.D + d.E'_{sh} + \varepsilon_{sh}$$

Where E = electricity consumption
E' = index that show the relationship between peak and average demand
T_{max} = maximum temperature
T_{min} = minimum temperature
M = dummy variable that reflect month (i.e., Jan=1, Feb=2, etc.)
D = dummy variable that reflects day-type (i.e., weekday and weekend)
Ɛ = error-term
s = state
h = hour

Equation (8-2)

Equation (8-2) is used to calibrate electricity demand for each hour for all five NEM states using historical data covering the period 2002-2011 (i.e. 3652 data points for each state). The result of this calibration is also used to assess how well these models predict hourly electricity demand. The hourly demand models developed in this study are found to be in reasonably close agreement with observations. A pictorial example of this comparison between modelled and actual demand for NSW is provided in Figure 8-4.

Figure 8-4 Comparison between actual and estimated intraday electricity demand



Note: The comparison is for a typical summer-day and winter-day (both weekdays and weekends) for NSW.

The performance statistics of these hourly demand models can be shown in terms of adjusted R^2, as provided in Table 8-4. It indicates that the adjusted R^2 varies between 0.62 (9pm and 10pm for SA) to 0.91 (12am and 4 am for NSW and 5am for QLD). These values are also in a similar range with other studies for Australia. Thatcher's (2007) model obtained R^2 in the range of 0.66-0.84, while the model developed by Howden and Crimp (2001) showed R^2 between 0.63 and 0.89.

Table 8-4 Adjusted-R^2 for hourly demand models for NEM states

	NSW	VIC	QLD	SA	TAS
01.00	0.83	0.74	0.80	0.63	0.71
02.00	0.88	0.78	0.83	0.66	0.66
03.00	0.90	0.83	0.87	0.68	0.65
04.00	0.91	0.81	0.90	0.64	0.65
05.00	0.89	0.76	0.91	0.66	0.63
06.00	0.83	0.74	0.89	0.64	0.66
07.00	0.83	0.77	0.85	0.65	0.68
08.00	0.81	0.79	0.83	0.71	0.78
09.00	0.80	0.77	0.81	0.69	0.79
10.00	0.77	0.77	0.81	0.66	0.81
11.00	0.73	0.72	0.84	0.65	0.80
12.00	0.71	0.71	0.85	0.66	0.75
13.00	0.71	0.70	0.86	0.67	0.72
14.00	0.71	0.70	0.87	0.68	0.68
15.00	0.71	0.70	0.87	0.69	0.68
16.00	0.71	0.69	0.87	0.69	0.67
17.00	0.68	0.68	0.85	0.69	0.69
18.00	0.73	0.65	0.79	0.64	0.83
19.00	0.82	0.74	0.72	0.64	0.88
20.00	0.80	0.73	0.75	0.64	0.86
21.00	0.82	0.71	0.77	0.62	0.84
22.00	0.85	0.74	0.80	0.62	0.85
23.00	0.88	0.79	0.81	0.64	0.83
00.00	0.91	0.78	0.83	0.68	0.76
Average	**0.80**	**0.74**	**0.83**	**0.62**	**0.74**

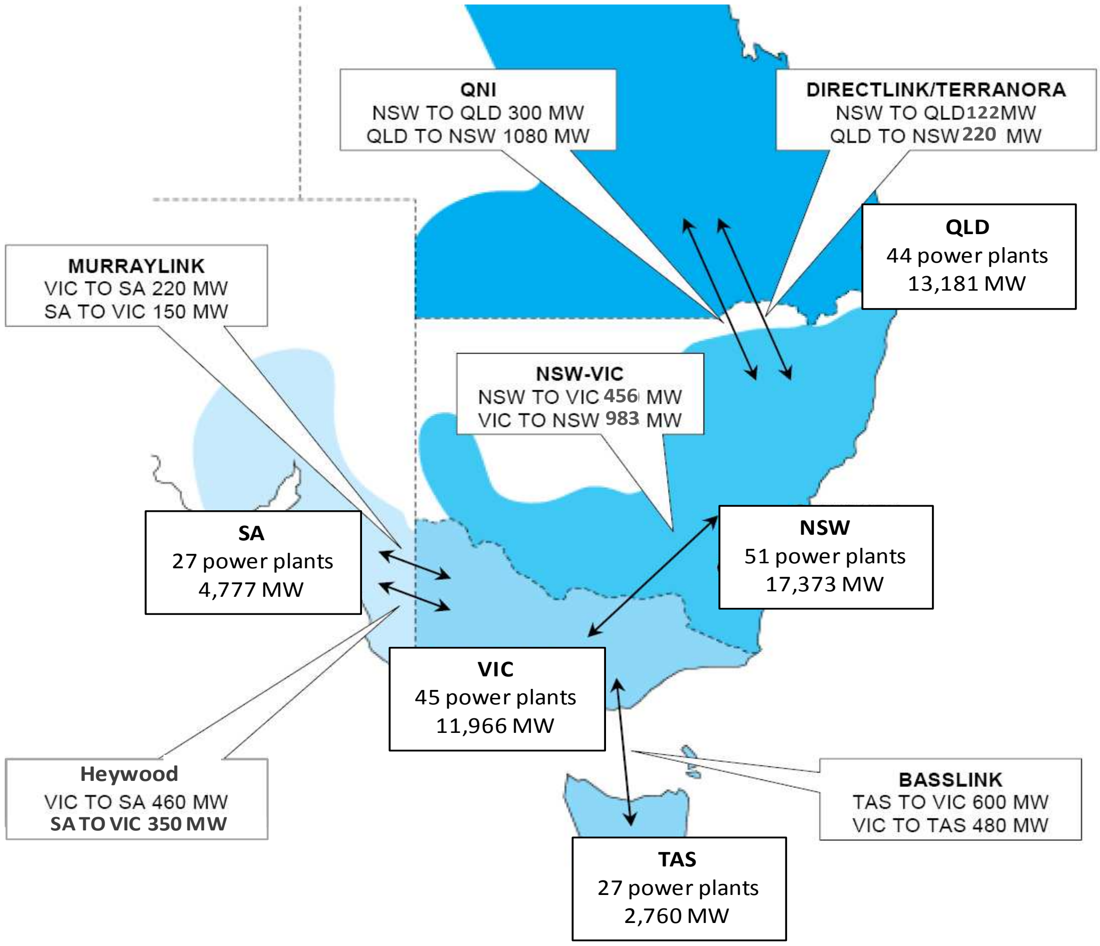
8.3.2.2 Electricity supply model

This study applies a dynamic partial equilibrium optimisation model - the TIMES model - to quantitatively model the impacts on electricity supply. The TIMES model is an energy sector model widely used in energy policy studies that provide cost efficient solutions, using a linear programming algorithm, thus making it suitable for use in identifying the least cost electricity supply strategy. The model minimises the total discounted cost of the energy system (in this study, NEM) over the long term. The total cost of the system consists of the cost of technologies (e.g. investment cost, fixed cost and variable cost of power plants), cost of energy use (e.g. coal, gas, etc.), and cost of emissions (through carbon price). In minimising the total cost the model chooses a mix of fuels and power plant technologies by taking into account their cost of installation and operation over the optimisation period. This is identical to maximising the net social surplus (i.e. the sum of the producer and consumer [prosumer] surpluses), which is a socially optimal objective.

The TIMES model is a demand driven model. Accordingly, electricity demand forecast for various climate change scenarios (using the method discussed in Section 8.3.2.1) are used as inputs to the model. The model is setup and run in the window-based interface ANSWER (Version 6) of the TIMES model. While the theory and mathematics underlying the TIMES model are complex, the ANSWER interface provides a user friendly platform to handle data and analyses the scenarios effectively. The window based interface ANSWER (Version 6) translates data input by the user into a linear programming (LP) problem with an objective function and constrains comprising a number of variables.

The proposed TIMES model for this study considers five Australian states in the NEM region, namely, Queensland, New South Wales, Victoria, South Australia and Tasmania. For each region, all existing power plants, as well as inter-regional transmission capacities are included (as shown in Figure 8-5). A total of 194 existing power plants are included in this study, with a total electricity generation capacity of more than 50GW. The information for these power plants is based on AEMO's assumption for their National Transmission Network Development Plan (AEMO 2011f). For new electricity generation technologies, the technical and economic characteristics are assumed based on the latest Treasury modelling (Australian Treasury 2011), in addition to AEMO (2011f).

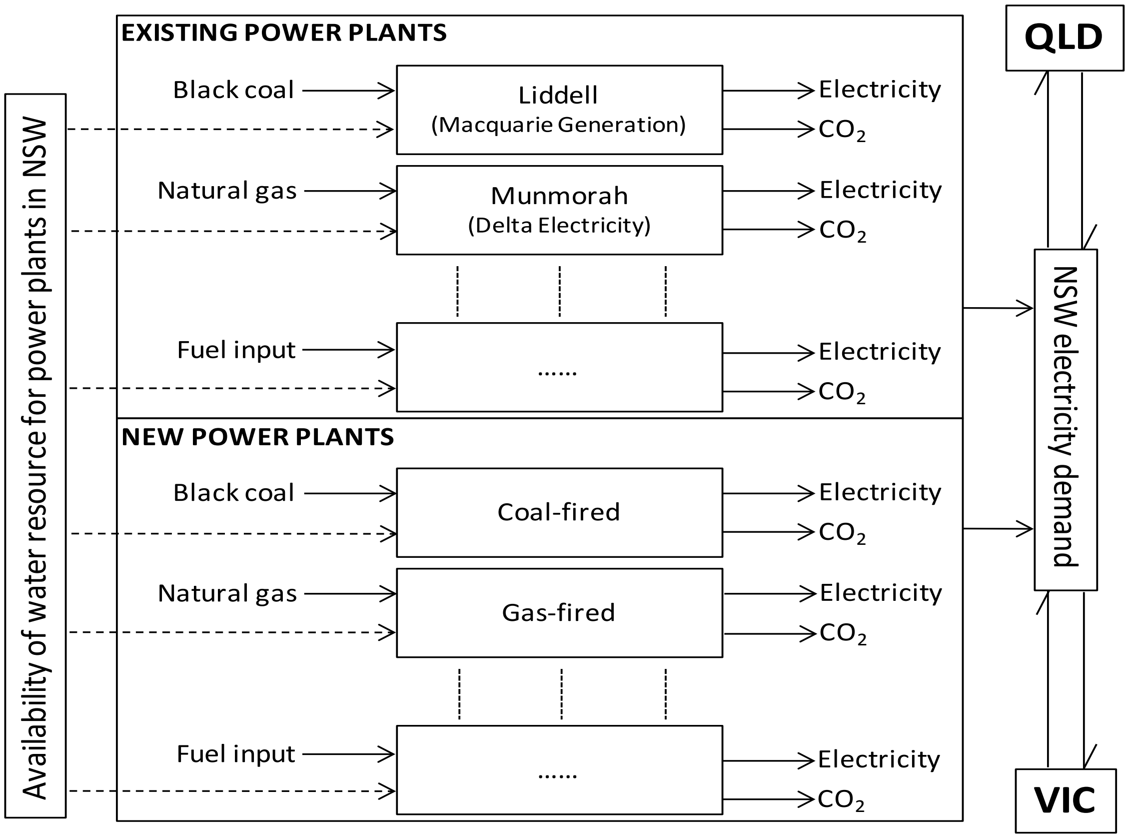
Figure 8-5 Existing generation capacities and interstate transmissions capabilities considered in this study



Sources: (BREE 2012; ESAA 2012; Tamblyn 2008)

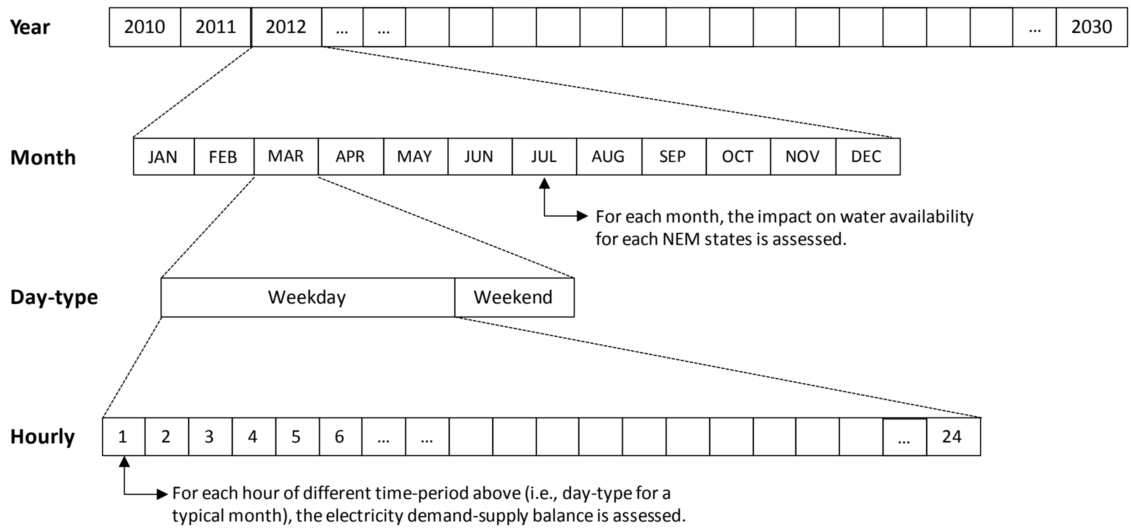
The building block of the electricity system for each region in the NEM, as developed in TIMES, is shown in Figure 8-6. This is essentially a Reference Energy System that represents a network of (part of) energy systems from resources that are used as inputs into power plants, through to the consumption of electricity. In addition to the use of fuel inputs by each power plant, the requirement for water in producing electricity by different power plant technologies (Table 8-2) is also identified. Thus the amount of water available for electricity generation in each state (determined using the method discussed in Section 8.3.2.3) will be a major constraint in TIMES in considering the mix of electricity generation technologies for meeting electricity demand in an optimal fashion. Each region is linked to other regions through transmission capacities that provide an option for interstate electricity trade.

Figure 8-6 Stylised Reference Energy System (for a typical state; NSW) used in this study



TIMES model is further extended in terms of its temporal resolution to allow the analysis to be made of short-term electricity dynamics. For this, each year is divided into twelve months, two day-type per month (i.e. weekday and weekend), and 24 hours per day, as shown in Figure 8-7. The division of the year into 576 time periods enables the modelling of several demand-supply dynamics. The division of the year into twelve months enables the consideration of seasonal variability, such as the amount of water available due to seasonal rainfall and availability of renewable resources that are dictated by seasonal weather patterns. The division into two types of day enables the consideration into weekly dynamics of electricity demand, as the load profile for a typical weekday is generally different from that of a typical weekend. Further, the division into daily dynamics enables the model to systematically balance daily demand patterns (i.e. peak and off-peak consumption) with hourly variations in renewable electricity production, particularly from wind and power sources.

Figure 8-7 Temporal resolution for the analysis in TIMES



8.3.2.3 Modelling water availability

While the amount of water consumption in power plants is estimated from TIMES, the total amount of water available for these power plants are estimated from a model developed in this study. From a review in Section 8.3.1.3 a sub-model is developed in this study to assess the impacts of climate change (e.g. reduced rainfall) on water availability. The result of this sub-model (i.e. the amount of water available) is then employed as a constraint for electricity generation in TIMES, as shown in Figure 8-6.

Without a detailed meteorological and water system information, and the application of a hydrological model, this study adopts a simple regression approach to estimate the relationship between water availability and the key climate variables. From the review, it appears that rainfall is one of the most important factors. Other factors are temperature and solar radiation. Data on monthly rainfall, solar radiation and temperature are regressed against water volume. All of this data is available on the website of the BoM. It was found that the temperature plays a negligible role and also not an important factor in determining the amount of water in the storages (as demonstrates by low t-values). Hence the model that is employed in this study is defined as:

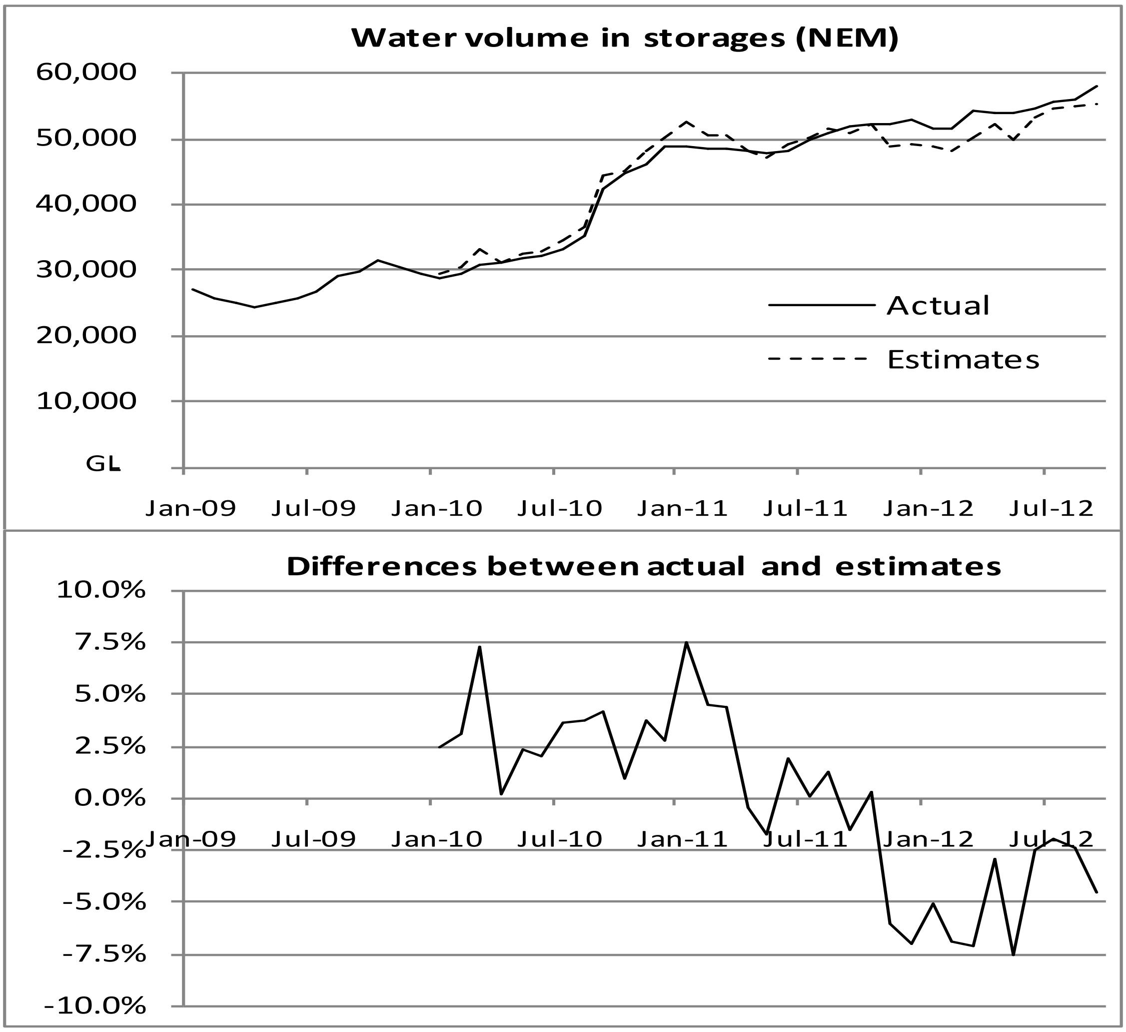
$$W_t = a + \sum_n b.R_{t-n} + \sum_n c.S_{t-n} + \varepsilon_t$$

Where W = total water volume available in storages across the state (in GL)
R = total monthly rainfall within the state (in mm)
S = exposure of solar radiation (in MJ/m^2)
Ɛ = error-term
t = year
n = number of lags

Equation (8-3)

Equation (8-3) is used to calibrate monthly water volume (in billion litres) for all five NEM states using data covering the period January 2009 to September 2012. (i.e. 45 observations for each state). The selection of this time-period is constrained by the first data-point for water volume in storages that is available from BoM (2012a). The result of this calibration is used to assess how well these models predict monthly water volume. This study has found that they are in reasonable close agreement with observations (Figure 8-8).

Figure 8-8 Comparison between actual and estimates of water volume in NEM storages



The performance statistics of the models in equation 8-3 are shown in Table 8-5. The model performance is well below the performance of the energy demand models, due to the fact that the number of observations is not that large, plus it covers the period where there is a large increase in rainfall and associated water amount as shown between July 2010 and January 2011. However, the adjusted R^2 are considered to be reasonable, with RMS error ranging from 3.86% (for Queensland) to 7.98% (for South Australia).

Table 8-5 Select summary statistics of the water model

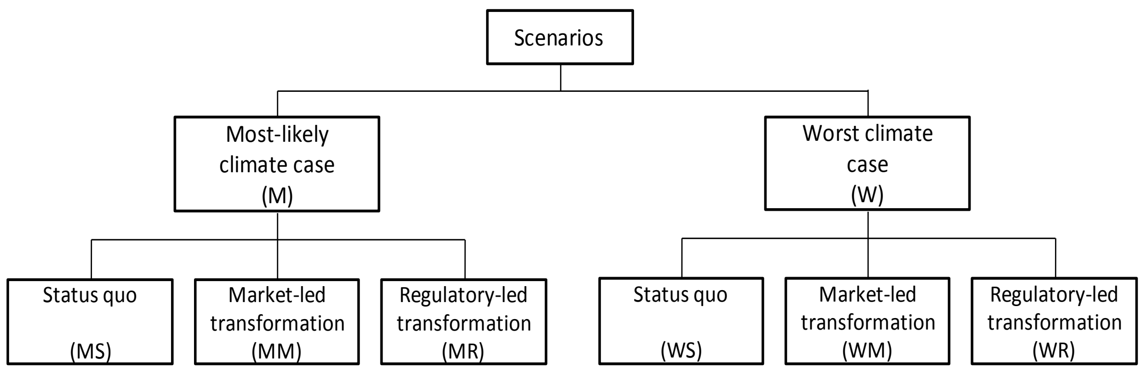
Statistics	NSW	VIC	QLD	SA	TAS
Adjusted R^2	0.8619	0.7581	0.7606	0.7112	0.6197
Durbin-Watson stat	0.84	0.85	1.61	0.82	0.84
RMS percent error	7.31	7.81	3.86	7.98	5.86

The results from this model are then used to determine the inputs into TIMES; this is the amount of water available for used in power plants. Based on the historical water accounts (ABS 2012d), the amount of water consumed in non-hydro power plants accounted for about 2 - 3% of total water used, while hydro power plants accounted for most of the in-stream water use. These proportions are assumed to remain constant in this study.

8.3.3 Scenario descriptions

This study employs a scenario analysis approach to analyse the impacts of climate change on electricity demand-supply balance, and also to assess the adaptability of the institutional arrangements within the NEM under various climate conditions. In all six scenarios are considered as shown in Figure 8-9.

Figure 8-9 Scenarios included in this study



Two distinct scenario paths are developed based on different climate patterns, namely the most-likely climate case (M) and the worst climate case (W). These climate cases for NEM are based on the national climate projections (CSIRO 2011), which are tailored from the standard GCMs for the six scenarios identified in the SRESs (IPCC 2007a). From a total of 138 possible future climate pathways (based on six SRESs and 23 GCMs), two paths are selected for this study. These two paths are consistent with SRES A1FI, which represents the worst climate conditions that could see the average global temperature rising to 4˚C above the 1990 level in 2100. Given the focus of this study on adaptation to climate change, this most extreme climate scenario is justified. In terms of choosing among 23 GCMs, this study adopts the approach suggested by the Tailored Project Services section of the CSIRO Division of Marine and Atmospheric Research (Clarke and Webb 2011) where MRI-CGCM2.3.2 model is considered as best representing the most-likely climate projection of the 23 GCMs conditional on the geographic region of the NEM, and CSIRO-Mk3.5 model is considered as best representing the worst climate case. Appendix A discusses the GCM selection process in more detail.

For each of the two climate cases (M and W), three scenarios that represent different types of institutions are also developed, namely, the status quo (S), the market-led transformation (M), and the regulatory-led transformation (R). For the status quo scenarios (MS and WS), the existing institutional arrangements of the electricity sector in NEM are assumed to remain intact. This means that the current government policies as well as the existing basis of electricity market operation are assumed to remain in place throughout the study period.

For the market-led transformation scenarios (MM and WM), it is assumed that the institutional arrangements will adapt in a way that accommodates market-based policies in balancing changes in electricity demand-supply, triggered by changes in climate conditions. For the regulatory-led transformation scenarios (MR and WR), the focus is for the institutions to rely more heavily on a regulatory-based policies in adapting the electricity sector in response to climate change. A more detailed discussion about the institutional scenarios follows in Section 8.5.

8.3.4 Climate change scenario assumptions

Key assumptions underlying the most-likely climate and worst climate cases take into account economic and demographic drivers, in addition to various climate change variables. In developing both climate scenarios, common assumptions are made about future growth in population and GSP up to the year 2030. These assumptions are broadly consistent with Garnaut (2008).

For population growth the latest release of population projections are used in this study (ABS 2008). Specifically, it employs Series B of the ABS projections, which reflects the most-likely case for population growth. Series A and Series C which reflect low and high population growth scenarios respectively are not employed in this study. Further, these ABS projections used 2006 population data as a baseline. This study however adjusts the population trend slightly by employing the actual population for 2010 and 2011 (ABS 2012b) and uses the same growth rate as projected by ABS (2008) to project population up to 2030. This is shown in Table 8-6.

For economic growth, the value of gross state products in 2010 and 2011 are taken directly from the Australian National Accounts (ABS 2012e). From 2011 to 2030, these are drawn from the assumptions used by the Treasury climate change mitigation modelling (Australian Treasury 2011).

Table 8-6 Scenario assumptions, 2010-2030

	NSW			QLD			VIC			SA			TAS		
	2010	**2030**		**2010**	**2030**		**2010**	**2030**		**2010**	**2030**		**2010**	**2030**	
Economic/demographic assumptions															
Population (Mn)	7.60	9.26		4.52	6.45		5.55	7.09		1.64	1.95		0.51	0.56	
GSP ($bn)	439.4	654.8		251.1	414.7		298.1	412.4		84.3	136.3		23.6	27.4	
Climate change assumptions		**M**	**W**		**M**	**W**		**M**	**W**		**M**	**W**		**M**	**W**
Temperature (˚C)															
maximum	22.9	24.8	25.5	25.6	30.9	31.5	20.0	20.5	21.1	21.7	27.3	28.1	18.4	15.4	15.9
minimum	14.9	11.6	11.9	15.3	17.3	17.6	10.0	8.8	9.1	12.0	13.1	13.5	8.4	6.5	6.7
Rainfall (mm)	532	516	485	588	563	541	631	612	559	223	217	194	1,333	1,320	1,228
Solar radiation (W/m^2)	185	185	187	205	205	207	153	153	155	194	194	196	137	138	138
Wind speed (m/s)	4.05	4.05	4.06	4.30	4.30	4.33	5.08	5.09	5.08	4.84	4.86	4.89	7.34	7.35	7.31

Sources: (ABS 2008, 2012b, 2012e; BoM 2012a; CSIRO 2011)

Notes: - M refers to the most-likely climate case and W refers to the worst climate case.
- Maximum and minimum temperatures refer to the average monthly temperature.

For climate change assumptions, these are taken from two climate scenarios (MRI-CGCM2.3.2 and CSIRO-Mk3.5) (CSIRO 2011) as discussed above. The selected climate variables are assumed based on the impact they might have on electricity demand and supply. These include maximum and minimum temperatures, rainfall, solar radiation, and wind speed. While Table 8-6 summarises values for these variables at average annual level, this study in fact employs monthly projections from CSIRO.

It is clear from these assumptions that the climate pattern are changing across all states (particularly in temperature and rainfall) even in the most-likely case, underpinned by the selection of IPCC's SRES A1FI. However, the differences in climate patterns between the most-likely and the worst climate scenarios are not too significant. This is due to the fact that much of the current stock of CO_2 in the atmosphere will remain in atmosphere for an extended period as a result of its long half-life (CSIRO 2007b), thus making climate projections fairly insensitive over the next 20 years or at least up to 2030 - the timeframe considered in this study.

Further, these climate change projections are based on 1990 baseline. These are currently being updated using a 2010 baseline and are not available for conducting analyses in this report. However, climate change is a slow process relative to the scope of this project being from 2010 to 2030, and over these 20 years there is little divergence as shown in Table 8-6. Thus the climate change projections using the new 2010 baseline should not differ too drastically from the climate change projections using the 1990 baseline.

8.4 Assessment of the impacts of climate change on electricity demand-supply

This section presents the results obtained from applying the methodology discussed in Section 8.3.2. Specifically it assesses the impacts of climate change, and associated changes in water availability, on electricity demand and supply balance for two climate change scenarios namely Most-likely (MS) and Worst case (WS), under the existing (status quo) institutional arrangements for the electricity sector.

8.4.1 Impacts of climate change on electricity demand

As population and GSP continue to increase (Table 8-6), demand for electricity would also increase. The summary results for electricity demand in 2030 under the MS and WS scenarios are shown in Table 8-7. The key findings are discussed below:

Table 8-7 Annual and peak electricity demand in 2030

	Most-likely climate (MS)				Worst climate (WS)			
	GWh	% change from 2010	MW	% change from 2010	GWh	% change from 2010	MW	% change from 2010
NSW	104,713	30.6	14,464	28.0	105,261	31.3	14,494	28.3
QLD	96,681	70.0	12,880	75.7	97,363	71.2	13,003	77.4
VIC	66,545	22.8	8,137	16.5	68,284	26.0	8,273	18.4
SA	21,454	37.2	2,430	21.7	21,439	37.1	2,442	22.4
TAS	12,990	5.1	1,520	4.4	13,112	6.1	1,509	3.6

Notes: MS refers to the most-likely climate case under the existing (status quo) institutional arrangements, while WS refers to the current institutions under the worst climate case.

- Under the most-likely climate trend scenario (MS), the annual electricity demand in the NEM region would increase by 38%, from 219TWh in 2010, to 302TWh in 2030.
    - Queensland will experience the largest growth in total electricity demand across the NEM region over the next 20 years. Demand would grow by 70%, from 56.9TWh in 2010 to 96.7TWh in 2030. This level of demand is equivalent to one-third of NEM's total electricity demand in 2030.
    - NSW would still be the largest consumer of electricity (35% of NEM-wide demand), with a projected consumption about 31% higher than today. This is equivalent to about 105TWh of electricity demand in 2030.
    - While all states will experience reasonably strong growth in electricity demand over the coming years, Tasmanian electricity requirement over the next 20 years would increase by just 5%, from 12,364GWh in 2010 to 12,990GWh in 2030. This reflects a combination of slow growth in population (11%) and economy (16%) and being the only state that the average temperature would be declining.

- If the climate situation becomes worse as in the WS scenario (i.e. temperature shifts towards warmer region), NEM-wide electricity demand would be about 1% (3,076GWh) higher than in the MS case, reaching approximately 306TWh in 2030. This is solely in response to assumed increase in average temperature level, with maximum temperature shifts within the range of 0.5˚ - 0.8˚C, and 0.2˚ - 0.4˚C shift in minimum temperature.
    - The impact of changes in temperature on annual electricity demand would be greatest in Victoria. For example, electricity demand in Victoria under the WS scenario would be 2.6% (1,738GWh) higher than in the MS scenario. This is equal to more than half of electricity demand growth across the NEM. The state that shows the second largest impact is Tasmania where demand under the WS scenario would be 0.9% higher, compared with the MS scenario.
    - The least effected state would be South Australia; in fact its total electricity demand would decline slightly as temperature increases. For example, total electricity demand in SA in 2030 under the WS scenario would be 14GWh less than in the MS scenario. This is despite a 0.8˚C rise in maximum

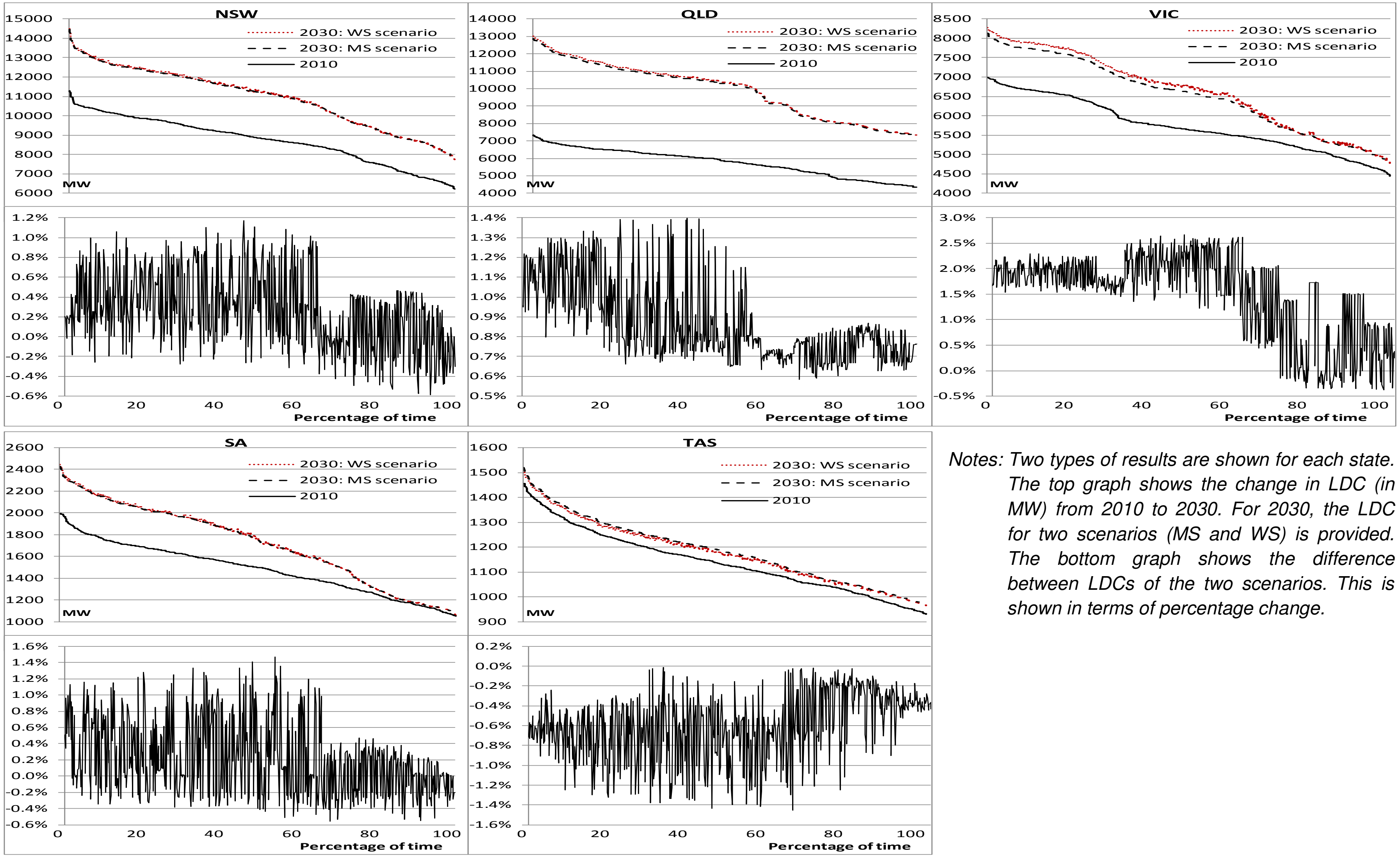
temperature (from 27.3˚C in the MS scenario to 28.1˚C in the WS scenario) and a 0.4˚C rise in minimum temperature (from 13.1˚C in the MS scenario to 13.5˚C in the WS scenario).

- When comparing the impacts of changes in temperature on peak electricity demand against the impact on annual demand, the results are not always consistent (Table 8-7).

  - The impact of climate change on peak demand (compared with annual demand) would be significant in Queensland and South Australia, and less-significant in NSW and Victoria. For example, while increase in temperature would lead the annual electricity demand in Queensland to be 0.7% larger in the WS scenario (against the MS scenario), the peak demand will be 1%.. On the other hand, increasing temperature would lead annual electricity demand in Victoria to grow at a faster rate (2.6%) than the growth in peak demand (1.7%).
  - While increase in temperature would lead to reduced electricity demand in South Australia in 2030, it would in fact result in a higher peak electricity demand – the peak demand in the WS scenario will be 0.5% larger, compared with the MS scenario.

- In terms of the responsiveness of peak electricity demand to climate change (i.e. change in peak demand when the temperature increases by 1˚C), the impact would be largest in Victoria where peak demand would rise by 3.6%. The impact on Queensland's peak demand would also be significant, rising by 2.1%. The impact will be comparatively lower for South Australia and NSW, where peak demand would increase by 0.9% and 0.4%, respectively. While other states are likely to experience an increase in peak demand, the demand in Tasmania would decline by 1.9%.

Figure 8-10 Impact of changes in temperature on load duration curves for NEM states



Notes: Two types of results are shown for each state. The top graph shows the change in LDC (in MW) from 2010 to 2030. For 2030, the LDC for two scenarios (MS and WS) is provided. The bottom graph shows the difference between LDCs of the two scenarios. This is shown in terms of percentage change.

- An increase in electricity demand over the next 20 years is estimated to be more concentrated during the peak period, rather than the off-peak period (Figure 8-10).

  - The result for South Australia, for example, clearly shows that there is almost no absolute increase in demand over the entire off-peak period, especially for 30% of the time that the demand is minimal. This very slow growth in demand would occur during the winter period as increasing temperatures during this period will relieve some pressure for electric-heating devices. On the other hand, electricity demand for the peak-period users could rise by 22%, from nearly 2000MW in 2010 to more than 2400 MW in 2030.
  - The same observation can also be made for Victoria and Queensland. For example, while demand during the off-peak period in Victoria would rise within the range of 6-7%, demand during the peak period would increase by more than 16%.

- When analysing the impacts of rising temperature due to climate change on overall load profile, specifically in terms of load-duration-curve, the impact is likely to be large during peak and intermediate periods, and much smaller (in fact almost negligible) in off-peak periods (bottom graphs in Figure 8-10).

  - When there is a shift in temperature as a result of climate change (MS versus WS scenarios), an increase in electricity demand for all states (apart from Tasmania) would be seen mainly during the peak periods.
  - Victoria, for example, shows the highest increase in peak demand in the WS scenario, its peak will be approximately 2% higher compared with the MS scenario. During the intermediate loads, demand in the WS scenario could be as high as 2.7%. The difference between the two scenarios will approximate to around 0.5% (on average).
  - Similarly for South Australia, the impact of rising temperature would lead demand during the off-peak period to change within the range of ±0.2%. In contrast, electricity demand during the peak period could rise by 1.2%.

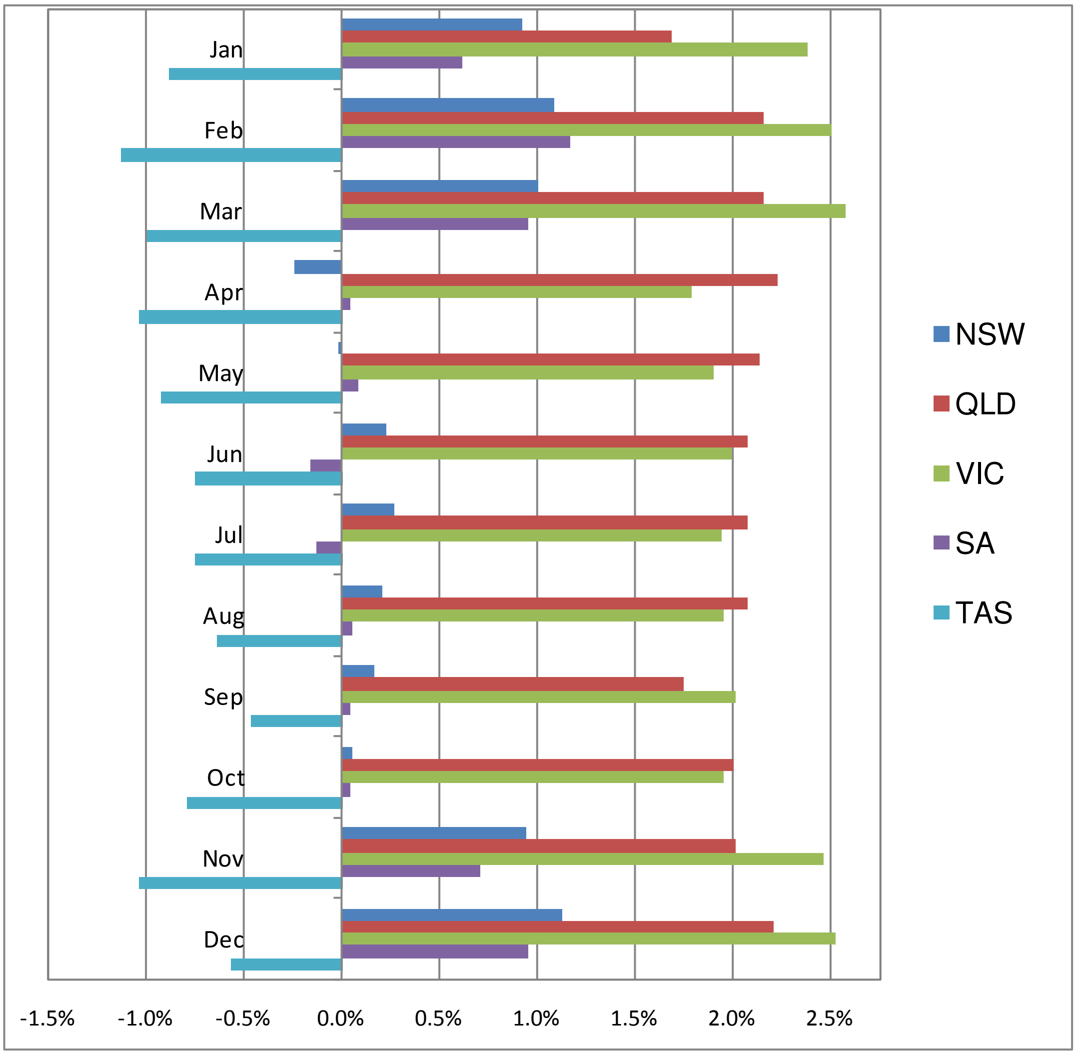
- The impacts of climate change on peak demand is likely to vary across the states in the NEM and it will also vary over the year (Figure 8-11). While rising temperature would lead to increased demand in Victoria and Queensland throughout the year, it would have an impact on NSW and South Australia demand mainly during summer months The peak demand in Tasmania would be lower as a result of climate change.

  - For NSW and South Australia, for example, electricity demand in the WS scenario would be higher (compared with the MS scenario) during the summer months (November-March), rising to more than 1% in February and December in NSW and rising to more than 1% in February in South Australia. On the other hand, the impact of rising temperature on electricity demand during the winter months in these two states would be negligible.

In fact, maximum demand would even decline in some months for example; April-May in NSW and June-July in South Australia.

- In Victoria where peak demand would rise the most when comparing to other states (as discussed above) these increases would mostly occur during the summer months (November-March); demand could rise by approximately 2.5%. This would occur as temperature becomes 0.7˚C hotter. Victorian electricity demand in the WS scenario would be higher for other months too, albeit to a lesser extent (2%).
- In Queensland, electricity demand in the WS scenario would be higher compared with the MS scenario throughout the year. This is due to the shift towards higher temperatures, where maximum temperature would rise by 6˚C (from 26˚C in 2010 to 32˚C in 2030) and minimum temperature would rise by 3˚C (from 15˚C in 2010 to 18˚C in 2030).
- In contrast to other states, electricity demand in the WS scenario (compared with the MS scenario) would be lesser throughout the year as increasing temperatures due to climate change would result in a more comfortable weather.

Figure 8-11 Differences in monthly maximum demand between the two climate change scenarios



8.4.2 Impacts of climate change (and water availability) on electricity supply

This subsection discusses the results obtained by the application of the TIMES model (as discussed earlier). The discussion focuses on four key attributes:

- electricity generation mix,
- cost of electricity supply,
- water use in power plants, and
- CO_2 emissions.

8.4.2.1 Electricity generation profile

Table 8-8 and Figure 8-12 show electricity generation profiles across the NEM under the two climate conditions and based on current policies.

Table 8-8 Electricity generation in NEM under the two climate scenarios

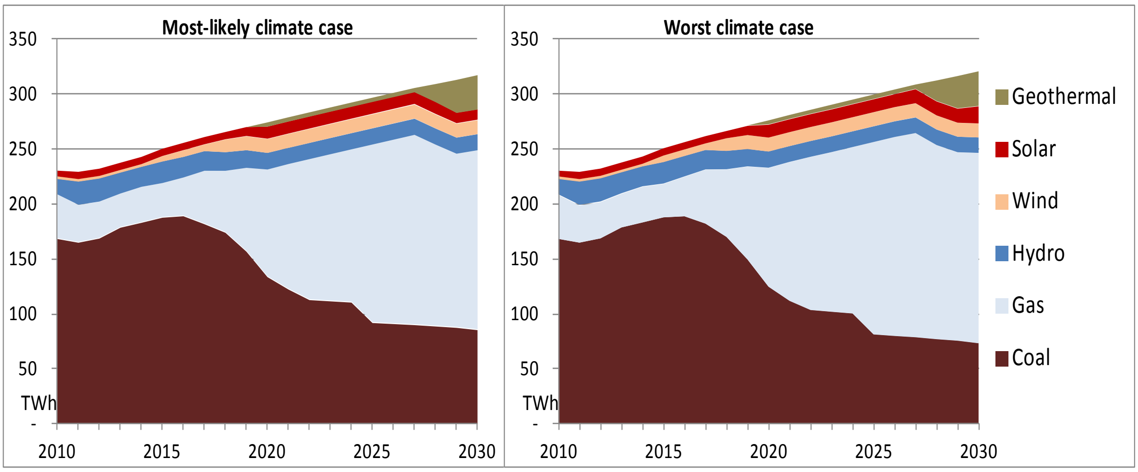
	2010 GWh	2020 GWh	2030 GWh	2010 %	2020 %	2030 %	2010-20 %pa	2020-30 %pa
	Most-likely climate							
Coal	168430	133783	85491	73.1%	48.8%	26.9%	-2.3%	-4.4%
Gas	39841	97470	163543	17.3%	35.6%	51.5%	9.4%	5.3%
Hydro	14412	15331	14783	6.3%	5.6%	4.7%	0.6%	-0.4%
Solar	2478	12727	12727	1.1%	4.6%	4.0%	17.8%	0.0%
Wind	5206	10917	9342	2.3%	4.0%	2.9%	7.7%	-1.5%
Geothermal	0	3942	31536	0.0%	1.4%	9.9%		23.1%
Total	**230368**	**274171**	**317422**				1.8%	1.5%
	Worst climate							
Coal	168430	125062	73755	73.1%	45.6%	23.2%	-2.9%	-5.1%
Gas	39841	107710	172671	17.3%	39.3%	54.4%	10.5%	4.8%
Hydro	14412	14969	14186	6.3%	5.5%	4.5%	0.4%	-0.5%
Solar	2478	12727	12727	1.1%	4.6%	4.0%	17.8%	0.0%
Wind	5206	11650	15459	2.3%	4.2%	4.9%	8.4%	2.9%
Geothermal	0	3569	31536	0.0%	1.3%	9.9%		24.3%
Total	**230368**	**275687**	**320333**				1.8%	1.5%

Key observations are:

- Under the most-likely climate trend, the annual electricity supply in the NEM region would increase by 37%, from 230TWh in 2010 to 317TWh in 2030 (or 1.6% per year).
- Overall electricity generation growth in both cases is similar, 1.8% per year in the near term and 1.5% per year in the medium term.
- Coal is likely to lose its significance in generation mix, substituting with gas and renewable energy. This will start to change after 2016-2017.
- Solar will gain importance in the near-term, while the share of geothermal will increase in the latter period as it is likely to become available for a base-load option.

- In the MS scenario, wind power is likely to taper-off during 2020-2030. However, in the WS scenario, where there is likely to be increased wind speed, wind power will continue to grow.
- Hydro power in the NEM is generating electricity at close to its full potential. As climate change is likely to bring dryness with it, the potential for hydro is likely to wane.

Figure 8-12 Electricity generation profile under the two climate scenarios

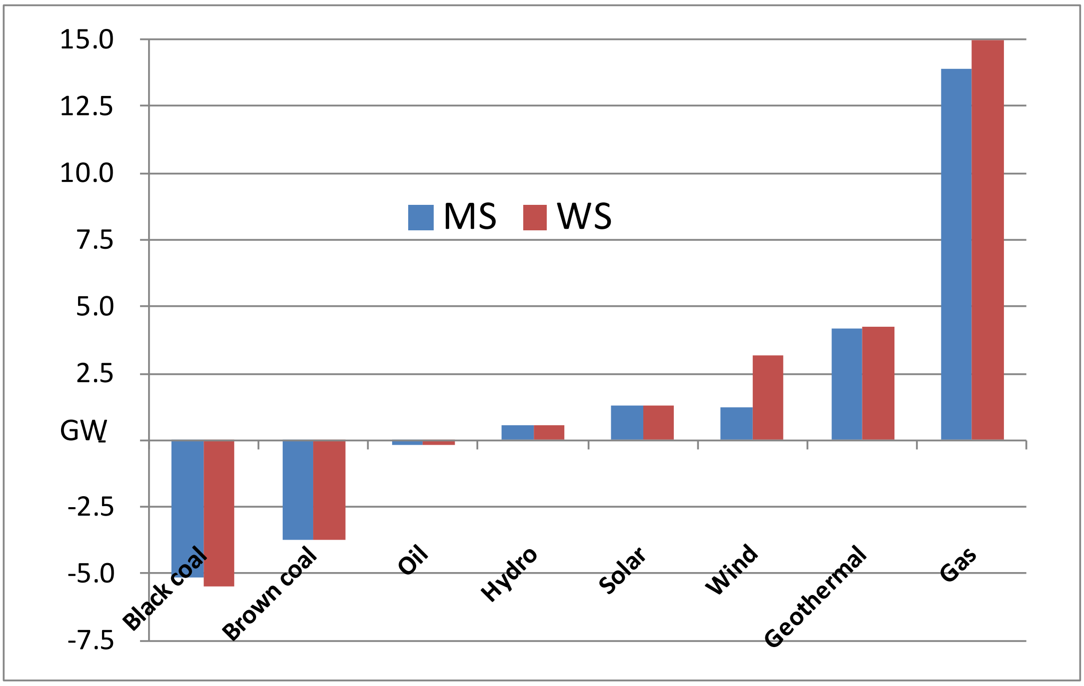


8.4.2.2 Electricity system expansion and investment

Figure 8-13 shows new generation capacity and retirements of existing capacity over the study period.

- Approximately 8500 MW of coal-fired capacity are likely to be retired, 25% of current capacity from black coal-fired, and about half of brown-coal fired. These changes are likely to be triggered by a combination of climate change (reduced water for thermal cooling), as well as current policies – the key policies such as carbon pricing and renewable energy target.
- As climate becomes more severe (as in WS scenario, compared with MS scenario), additional capacity of black coal-fired would be affected. The winner would be gas-fired and wind power, as they require less water and are more resilient to operate under severe weather conditions.

Figure 8-13 Changes in electricity generation capacity under the two climate scenarios



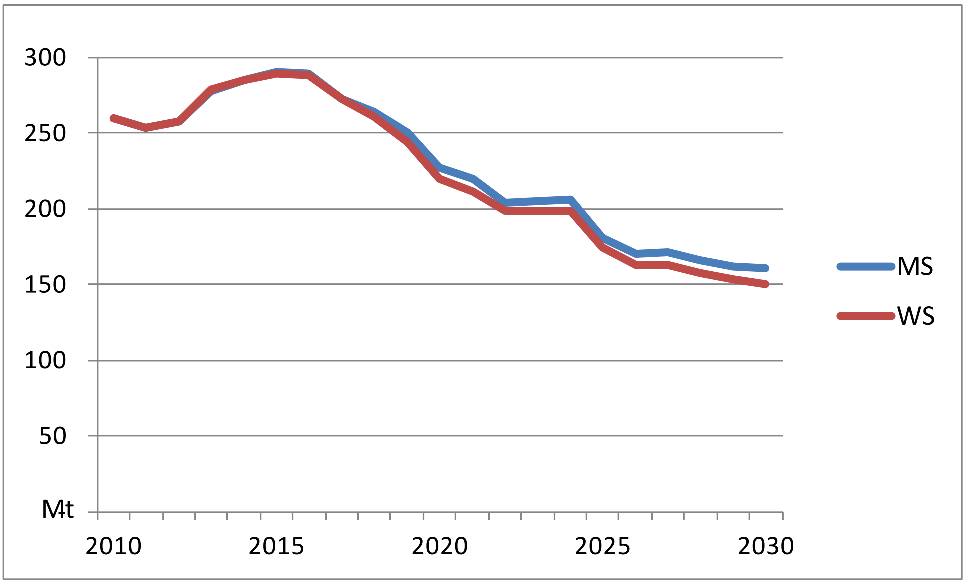
- These changes in electricity supply capacity means that there will be a need for investment over the twenty-year period (up to 2030). It is estimated that under the MS scenario, the changes in supply system would require approximately $51 billion (in real 2010 value), while in the WS scenario an additional $4 billion would be required.

8.4.2.3 Carbon-dioxide emissions

Figure 8-14 and Figure 8-15 show total CO_2 emissions level (Mt) and CO_2 emissions intensity (in ton per MWh electricity generated) for NEM respectively.

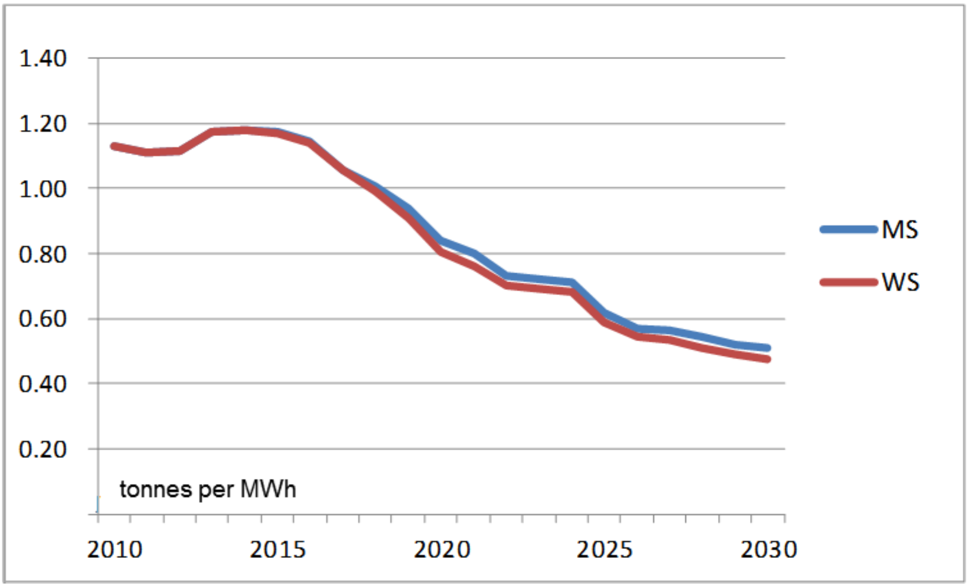
- Carbon emissions in both scenarios are expected to decline as less intensive sources of electricity generation gain in their market share. This is likely to happen after 2015 as coal-fired electricity generation begins to phase-out from the electricity market.

Figure 8-14 Carbon emissions under the two climate scenarios



- NEM's average emissions intensity is currently about 1,100 tonnes per GWh. This is likely to fall to around 500 tonnes per GWh by the end of 2030.
- Under the WS scenario, CO_2 emissions and intensity are likely to be lower than that under the MS scenario. This is due to higher penetration of renewable energy into electricity market, driven by changing weather patterns and current climate-related policies that are in place.

Figure 8-15 Carbon intensity under the two climate scenarios



8.5 Assessment of the adaptability of existing institutional arrangements to climate change

Institutional arrangements in the context of this study refer to the structure (such as market design, spot pool and market trading), ownership (e.g. public, private or public-private) and regulation (e.g. rules and processes for market operation and pricing) of the electricity market. These arrangements have been developed on the bases of certain assumptions about the nature of electricity market, consumers' and producers' behaviour and the influence of climate variability on demand and supply. The recent extreme climate conditions appear to have exceeded these assumptions and have consequently impacted the working of the electricity market. In effect, it has called into question the integrity of existing institutional arrangements. The question is "To what extent are the existing arrangements likely to be able to adapt to extreme climate without compromising the integrity of the electricity system?".

This section provides some discussion of the possible implications of climate change and associated water availability and consequential change in electricity demand and supply, on key electricity market arrangements. Specifically it extends the analysis performed in Section 8.4 by assessing two additional institutional scenarios for each of the two climate pathways. In other words, it assesses the impacts of scenarios MM/MR against MS, and WM/WR against WS, as shown in Figure 8-9.

8.5.1 Institutional arrangements in the National Electricity Market

8.5.1.1 Structure

Under the current NEM trading arrangements, generators sell and retailers buy electricity through a wholesale spot market. AEMO coordinates a central dispatch process to manage the wholesale spot market. This process matches generator supply offers to retailers demand bids in real time. Changes in supply and demand conditions in this market determine prices. Consumers partly respond to these prices in their consumption behaviour, while producers plan for future investment based on these prices. AEMO monitors demand and capacity across the NEM and issues demand-supply forecasts to help producers and consumers respond to the market requirements. Thus, demand and supply forecasts play an important planning and market balancing role in ensuring a smooth operation of the market. The impacts of climate change and associated water availability on electricity demand- supply conditions, as identified in Section 8.2, allude to the possibility of changes that may be required to be made to the existing trading arrangements.

Climate change mitigation policies may affect the pattern of generation technologies across the NEM. These policies may change the economic drivers for new investment, and may shift the reliance of electricity generation from coal towards less carbon-intensive sources. For example, the Government has committed to increase the share of renewable energy technology in the electricity generation mix (to 20% by 2020) through the RET scheme. During 2011, the renewable energy certificates (created under the RET scheme) from large-scale renewable electricity generation traded at around \$35-\$40, while the price of certificates from small-scale plants traded at a wider, but relatively lower, range at \$20-\$40 (AER 2011). This suggests that small-scale distributed generation from renewable sources is likely to play an increased role in electricity market in the years to come. This could lead to a very different wholesale market structure. In addition, a carbon price has already started from 1 July 2012 as part of the Government's Clean Energy Future plan, which aims to reduce greenhouse-gas emissions to at least 5% below 2000 levels by 2020 (Australian Treasury 2011). This policy may lead to a very different technological structure than we have today, and thus change the landscape on how NEM operates.

8.5.1.2 Ownership

As climate change will induce changes in both the technological structure and the way market operates, this may contribute to increased price volatility. The price volatility is generally factored in as a higher risk premium in the contract prices. Consequently, market participants (generators and retailers) may find it difficult to obtain long-term contracts that are sufficiently long enough to justify investment in long-lived electricity infrastructures. Because of the uncertainty in the rate-of-return on capital investment, there may possibly be a shift in private investment in the electricity market. New investors may find it even more difficult to enter the market, in addition to the fact that their cost structure is generally higher than the existing market participants, while the existing investor may be tempted to continue their investment in the electricity sector. This may hinder the support for further privatisation of the electricity industry.

8.5.1.3 Regulation

Changes in market trading arrangements identified above could also influence regulatory arrangements. For example, CCS technology is expected to play an important role in the electricity market in the coming years. Stanwell proposes to build a power plant with CCS in Queensland. This plant is expected to commence operation by 2017-18 (AER 2011). However, this technology would require a very different regulatory framework as it involves different types of risks at both national and international levels, including the liability for long term carbon storage, regulation of transport, the treatment of stored carbon under emissions trading regimes and issues of property ownership (Havercroft, Macrory & Setwart 2011).

Also, changes in the technical structure of electricity generation from large-scale centralised power plants to small-scale distributed generation, would require very different electricity networks. Currently electricity network operators need to apply to the AER for assessing their revenue requirements. As part of this application, they are required to conduct a regulatory test to determine whether the proposed network passes a cost-benefit analysis. Based on this, the structure of prices is determined for third-party access. Under the current regulatory arrangements, for example, the network operators control access to information regarding their networks. Therefore only the service providers know the true value of their networks, and they can therefore influence access to networks by others, by reporting their benefits that are lower than the actual values (or reporting the costs that are higher than the true cost) to the extent that it is still pass the regulatory test. This appears to create asymmetry of information between network operators and say owners of distributed generation whose increasing presence may reduce the need to augment electricity network.

In some area within the NEM region, electricity supply systems can be vulnerable to the effects of sea level rise and extreme weather events, especially the coastal areas. In these areas, the siting of new supply systems could face increased restrictions. Incorporating possible climate change impacts into the planning processes has a potential to improve the resilience of electricity supply infrastructures.

As discussed in Section 8.2.3.2, decreased water availability will affect power plants. As a consequence, competition for water supplies will increase between electricity generation and other sectors. The understanding of this climate-electricity-water nexus will help identify the cross-sectoral regulations to be harmonized.

Also, various types of energy resources are distributed unevenly across states within the NEM. The emergence of climate change impacts and carbon mitigation policies are expected to change the electricity demand-supply balance of different states. This may lead to a change in the relative ‘power’ of individual political jurisdictions in the NEM. To allow the effective adaptation, it may require some re-negotiation of current market arrangements through the intergovernmental regulatory response processes across all levels of government.

8.5.2 Description of institutional arrangement scenarios

From a description of scenarios that introduced in Section 8.3.3, three scenarios are developed to represent different institutional structures:

- status quo (S),
- market-led transformation (M), and
- regulatory-led transformation (R).

These three scenarios are employed in conjunction with the two scenario paths (M and W) to make six scenarios in total. Two of these (MS and WS) were analysed in Section 8.4, and the remaining four scenarios (MM, MR, WM and WR) are assessed in this section. This subsection continues to describe the institutional scenarios employed in this study.

The discussion in Section 8.5.1 suggests that the bases to which the sector operates, the policies that act as an incentive for the sector’s participants, and the type of technology used in the sector (which can also be influenced by the first two factors) are all outcomes of a particular institutional arrangement. Thus a scenario to capture different institutions can be designed by varying these factors. Skoufa and Tamaschke (2011) employed a similar approach in designing institutional scenarios (private cost versus social cost scenarios) to analyse the relationship between institutional change and technological change for electricity supply sector in Queensland and Victoria.

In all three institutional scenarios, the same basis for analyses is applied, by considering the long-run marginal costs of electricity supply to rank power stations. Hence a pool price based on costs, rather than the bids used by AEMO, is a key criterion to determine electricity (technology) supply options. The assumptions about policies and the influence it has on electricity generation technologies would however be different (Table 8-9).

Table 8-9 Scenarios descriptions for electricity supply modelling

	Status quo	Market-led transformation	Regulatory-led transformation
Carbon reduction policy	Carbon pricing	Carbon pricing	Very low world carbon price (based on EU experience)
Technology-specific policy	RET Queensland Gas Scheme Support for CCS	Not applicable	RET (extended target) QLD gas (extended target)
Water access arrangement	Contract and licensing	Water pricing	Contract and licensing

The key existing policies that are included in the status quo scenario are the carbon price, the Australian Government RET, and the Queensland Gas Scheme. The carbon price assumptions are set in reference to the Treasury climate change mitigation modelling (Australian Treasury 2011). The carbon price starts in 2012-13 at $23 per tonne, and grows at 5% per year for three years. After that the carbon price will move into an emissions trading scheme, which is open to the world market where prices will be determined by this market. In this study, the future carbon price is adopted from AEMO (2012a).

For RET, the Government is committed to deliver a target of 20% renewable electricity by the year 2020. In the status quo scenario, this target is assumed to remain fixed throughout the study period (up to 2030).

For the market-led transformation scenarios (MM and WM), it is assumed that the institutional arrangements will adapt in a way that accommodates market-based policies in balancing changes in electricity demand-supply, triggered by changes in climate conditions. To model this scenario, it is assumed that policies to support a particular technology will not play a role in this type of institution; the institutional ideology of the market is to 'let the price decide'. Thus it is assumed in this scenario that a stronger carbon price will be implemented as a substitute for RET, as well as the Queensland Gas Scheme. In addition, based on the premise that water is also a scarce resource, and the electricity user has to compete for it uses against other users. Thus a water price is also introduced in this scenario. Specifically, the scenario identifies that the water user must pay an initial price of $3000 per ML of water in 2013 (consistent with water entitlement market prices employed within the Murray-Darling Basin). This price is assumed to increase at the same rate as carbon price, which is around 8% per year.

For the regulatory-led transformation scenarios (MR and WR), a focus is for the institutions to rely more heavily on regulation-based policies in adapting the electricity sector in response to climate change. In this scenario, a carbon price is assumed to remain in place for just three years (2013-2015), and the use of water is assumed to be the same as in the status quo scenario, which is based on contract and licensing. In the absence of this type of pricing scheme, technology-specific policies such as RET and the Queensland Gas Scheme are assumed to further strengthen. For example, RET is assumed to be extend to meet a target of 25% by 2030, while Queensland Gas Scheme target is also increased to meet a 24% level by 2030.

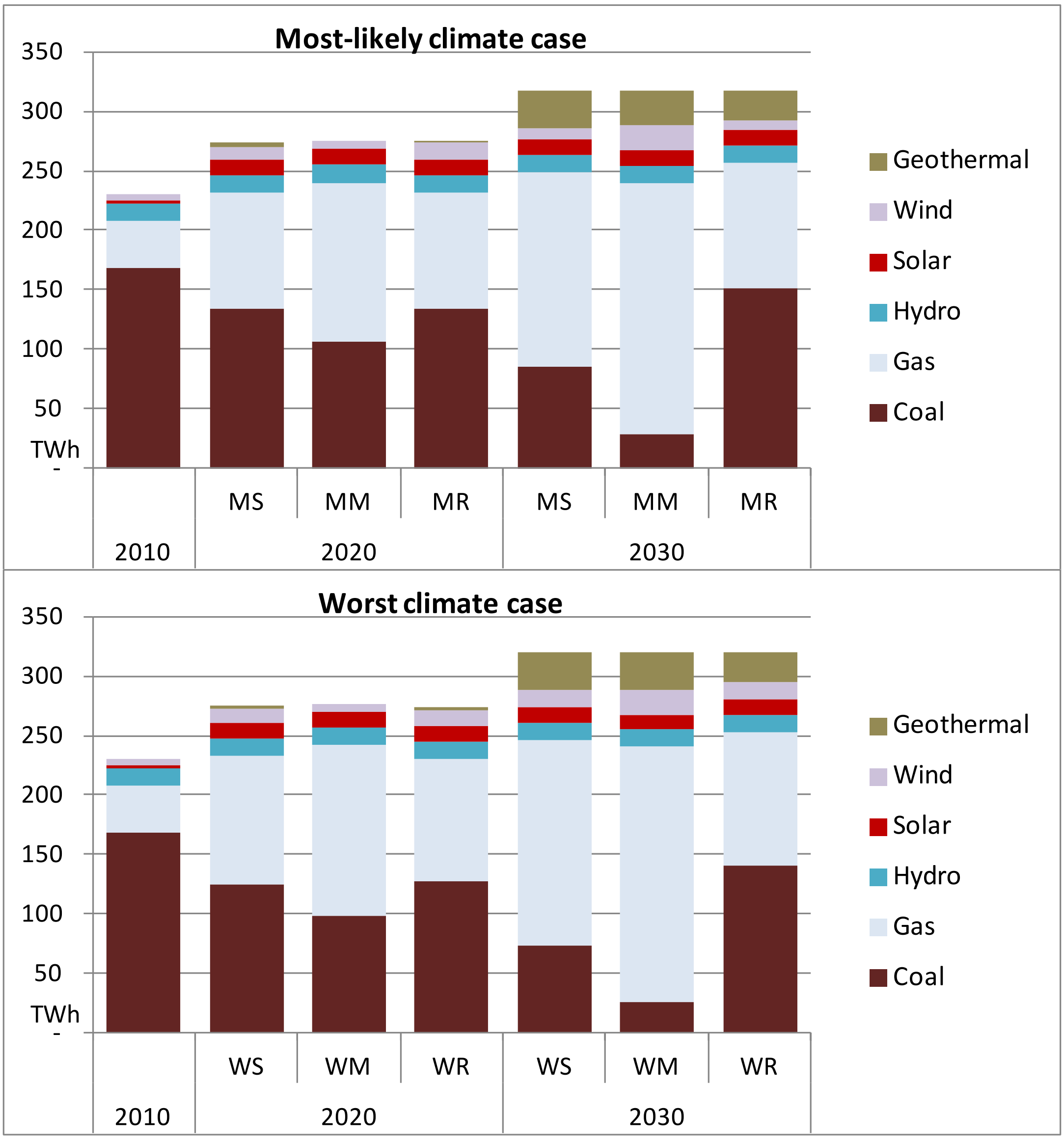
8.5.3 Assessment of alternative institutional arrangements

This subsection presents and discusses the results of the two climate change scenarios (most-likely against worst case) under the alternative institutional arrangements of the electricity sector – this is shown as Scenarios MM/MR and WM/WR in Figure 8-9. The results can be compared to those discussed in Section 8.4.2 where the impact of climate change under the existing institutional arrangement (status quo) was assessed; this is also incorporated in the discussion in this section.

8.5.3.1 Impact on electricity generation profile

Figure 8-16 shows electricity generation for NEM as a whole under the two climate conditions, and three alternative institutional paradigms.

Figure 8-16 Electricity generation mix by fuel type



Key observations include:

- Policies stemmed from different institutional settings generally lead to a very different outcome to the electricity sector;
    - Under the regulatory approach, the electricity generation structure is not expected to change drastically. Coal, for example, is likely to remain as a main source of fuel for electricity generation. While its importance would certainly reduce due to the shift towards a clean energy future, it would still contribute to about half of electricity generation in the NEM in 2030 (from current contribution of more than 70%). In the status quo case, its share would reduce to below 30%. Natural gas, on the other hand, would improve its share of total electricity generation in a more moderate manner, rising from current contribution of 17% to just above 30% in 2030. This compares with half of total electricity production from gas-based fuel under the current policy settings.

- In the opposite of the regulatory approach, the market-led transformation would drastically change the electricity generation mix in the years to come. For example, the importance of coal-fired power plants would not just simply reduce under the price 'signal' paradigm, but coal would become a less important fuel source for electricity production; it would have about the same contribution as geothermal in 2030 (less than 10%). This means that natural gas would have relatively the same importance as coal has today, with the share of electricity production increasing from the current level (17%) to become greater than two-third of all the sources.

- While the policy signal from different institutions can lead to a very different electricity future, the outcomes of each institutional setting are consistent under the different climatic conditions.

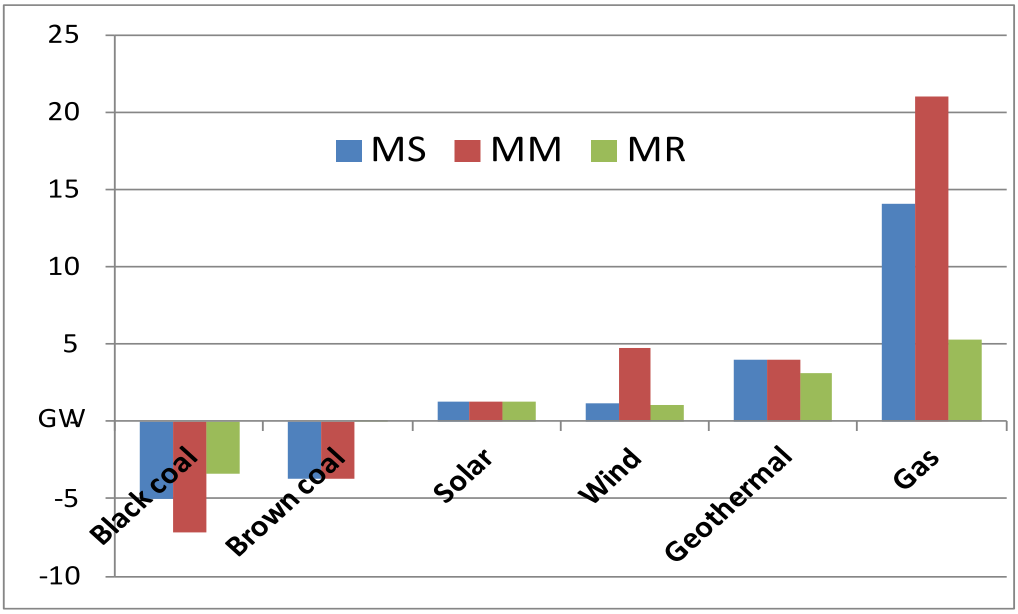
  - Under both climate futures, the importance of coal would still remain under the regulatory approach, while gas would take the place of 'king coal' under the type of institution that often adopt the market-based policies in transforming the economy.
  - Also, in all scenarios considered in this study little difference is shown in the way renewable electricity technology is adopted in the market; the share of solar, wind and geothermal are broadly the same across all scenarios.

8.5.3.2 Impact on electricity system expansion and investment

Based on the impact on electricity generation profiles, the following changes are likely to occur with regard to the electricity supply system.

Figure 8-17 shows new generation capacity and retirements of existing capacity over the period 2010-2030 for three institutional arrangement cases under the most-likely climate condition.

Figure 8-17 Changes in electricity generation capacity under alternative institutional paradigm



- As discussed in Section 8.4, approximately 8,500 MW of total coal-fired capacity are likely to be retired under the MS scenario, triggered by a combination of climate change (reduced water for thermal cooling), as well as existing policies. Thus there is an increase in less-emissions intensive as well as water intensive electricity generation technology.

- Under the market-led transformation (MM) scenario, about 11,000 MW of coal-fired capacity could be mothballed, given the cost disadvantage that these generations are likely to face under a more stringent carbon pricing regime. Similar to the current policy environment, the comparative advantage of gas-fired would be strikingly shown in the near- to medium-term. While an increase in the capacity of renewable-based electricity could fully offset a decline in coal-fired generators (of about 10GW), an increase in gas- fired capacity (around 20GW) could solely meet an anticipated rise in electricity demand.

- All these changes in electricity supply capacity mean that there will be a need for investment over the study period (up to 2030). It was shown in the previous section that the changes in supply system under the MS scenario would require approximately $51billion (in real 2010 value) for building these new capacities. In the MR scenario, the value of investment would be about the same as in the MS scenario, while the market-led transformation would need $6billion in more investment to support drastic change in the electricity supply structure. Under the worst climate case these investments value could rise to $60billion.

8.5.3.3 Impact on ownership of electricity generation assets

As eluded above that the current market participants may have cost advantage over the new investors, which may cause barrier to entry into the market to some extent. In addition, the existing participants may on the other hand also be tempted to invest in new electricity infrastructure given the high risk premium associated with price volatility, and thus difficulty in obtaining long-term contracts to justify further investment to expand the electricity supply system. To this end, it is worth noting some of the possible changes in the ownership of generation assets as results from the implementation of policies identified in the scenarios.

Table 8-10 shows the list of private companies (and public utilities) that currently own 80% (in total) of electricity generation capacities in NEM. It also provides the percentage change in their ownership in 2030 for the three scenarios. This of course does not account for further investment that these entities will make to further expand their portfolios from the upcoming new capacities.

Table 8-10 Percentage share of ownership in the electricity generation capacities

	2010	2030		
		MS	MM	MR
Delta Electricity	10.2%	4.1%	2.9%	4.1%
Macquarie	10.0%	4.5%	3.9%	4.8%
Snowy Hydro	9.0%	7.2%	6.3%	7.8%
International Power	7.4%	1.8%	1.6%	2.8%
CS Energy	6.4%	4.4%	3.8%	4.7%
Eraring Energy	6.4%	5.4%	4.8%	5.9%
Tarong Energy	5.4%	4.3%	3.7%	4.6%
AGL Energy	5.0%	2.1%	1.8%	2.3%
Loy Yang Power	4.5%	3.6%	3.2%	3.9%
TRUenergy	4.3%	1.0%	0.9%	1.0%
Origin Energy	4.1%	3.2%	2.8%	3.5%
NRG Gladstone	3.5%	2.8%	0.0%	0.0%
Stanwell Corporation	3.3%	2.6%	2.3%	2.8%
Top ownership	80%	47%	38%	48%
New capacity		39%	50%	36%

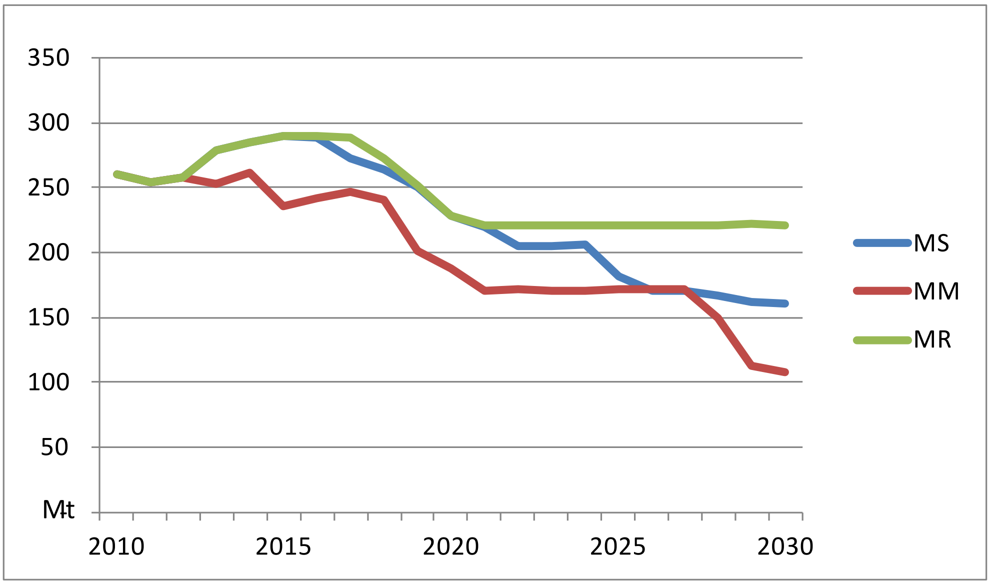
- Most of the changes in ownership would occur under the market-led transformation scenario. Overall the ownership of these 13 entities could reduce from the current level of 80% to 38% in 2030. This is not unexpected as this scenario would lead to a drastic change in the electricity generation mix and associated capacities to supply that mix. Some electricity generation assets that these entities owned could become uncompetitive, and thus be forced out of the market.

- In contrast, the impact of changes in ownership from the regulatory-led transformation scenario is more moderate. The impact is potentially the same as the current policies (as in MS scenario).

8.5.3.4 *Impact on carbon-dioxide emissions*

Figure 8-18 shows total CO_2 emissions level (in Mt) for NEM. The figure clearly shows that emissions from the electricity sector could be contained under all three scenarios.

Figure 8-18 Carbon emissions under the three institutional scenarios



- Carbon emissions in all three scenarios are expected to decline as less intensive sources of electricity generation gain comparative advantage to increase their market share. A decline would happen straightaway in the MM scenario as carbon prices began to kick-in during 2012-2013, which follows by a more aggressive carbon price.

- This is in contrast to the other two scenarios (MS and MR) where emissions would rise in the short-term before tapering off during the second half of this decade. This is due to a slow adjustment in the retirement of coal-fired electricity generation capacity.

9. ASSESSING THE CURRENT INSTITUTIONAL ARRANGEMENTS FOR THE DEVELOPMENT OF ELECTRICITY INFRASTRUCTURE TO INFORM MORE FLEXIBLE ARRANGEMENTS FOR EFFECTIVE ADAPTATION

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The previous Chapters have identified current institutional arrangements that are sources of maladaptation to climate change. This chapter discusses these sources of maladaptation in more detail to provide a measure of adaption to climate change and to suggest alternative more flexible arrangements to climate change. Four key issues were identified:

1. fragmentation of the NEM both politically and economically;
2. accelerated deterioration of the transmission and distribution infrastructure due to climate change requiring mechanisms to defer investment in transmission and distribution;
3. lacking mechanisms to develop a diversified portfolio of generation technologies and energy sources to reduce supply risk; and
4. failing to model and to treat the NEM as a national node based entity rather than state based.

Section 6.1 discusses how the transmission and distribution infrastructure will be subjected to accelerated ageing and subject to more faults from higher winds and temperatures. As discussed, the higher frequency of faults can be ameliorated by better design and improved maintenance but both act to increase the cost of installing new lines and running existing lines. This sensitivity of transmission and distribution to climate change makes the deferment of transmission investment more important. This chapter particularly scrutinises institutional arrangements to highlight potential sources of maladaptation to defer investment in transmission and distribution.

Stevens (2008, p. 41) discusses if the energy sector infrastructure is to adapt to climate change, a totally integrated holistic approach to the provision and management is required. Stevens notes that this approach is particularly relevant to the electricity sector and identifies two impediments to achieving suitable outcomes being the intensely competitive environment and the diverse ownership of infrastructure. So, this chapter compares the adaptation to climate change of the South Korean and Australian electricity systems to provide a gauge to Australia's success. The contrast highlights the success of the simple institutional structure of South Korea's national government and electricity monopoly over the complex institutional structure of Australia's State Governments and diverse ownership of infrastructure. Section 4.4 expands upon the comparison between these two markets.

Section 6.12 discusses the need to develop a portfolio of energy to reduce supply risk where the RET provides onshore wind and solar PV with a first mover advantage at the expense of a broader portfolio of energy. This first mover advantage for solar PV is exacerbated by the solar bonus built into a feed-in tariff.

This chapter discusses the four key issues in the following subsections.

9.1 Feed-in tariffs incorporating a renewable energy bonus

This section discusses feed-in tariffs incorporating a renewable energy bonus where the bonus acts a as a source of maladaptation but an economically neutral and sustainable feed-in tariff is essential to the development of a smart grid and adaption to climate change for the NEM.

The International Energy Association (IEA 2011c, p. 33) observes that nearly all countries now offer or are planning feed-in tariffs for solar PV but debate has shifted from *'if or how to implement a feed-in tariff'* to *'how to move to a self-sustaining market post feed-in tariff'*.

This section discusses feed-in tariffs as a source of four market failures:

- inappropriate infant industry assistance;
- exacerbating inequity;
- inadequate transmission investment deferment price signal; and
- poorly targeting myopic investment behaviour.

Additionally, this section discusses a sustainable feed-in tariff regime that addresses the four market failures together with an international comparison of feed-in tariffs.

IEA (2011c, p. 33) acknowledges internationally feed-in tariffs have been poorly designed or poorly controlled resulting in explosive markets, profiteering, political interference, over-reliance on imports, market collapses, business closures and so on. However there is now a wealth of information available worldwide to policymakers regarding the impact of various designs of feed-in tariff schemes and how and when to adjust tariffs to avoid overheated markets. Gipe (2011) provides an extensive and current discussion of feed-in tariffs.

Under the guise of an infant industry argument, the states in Australia implemented feed-in tariffs to establish the domestic PV industry. This policy has been overly successful but has produced maladaptation by creating inconsistent gross or net feed-in tariffs calculation across Australia resulting in inconsistent remuneration, causing cross subsidy of electricity resulting in inequity to favour the rich over the poor, testing policy credibility, creating poorly targeted infant industry assistance and failing to target transmission investment deferment.

The problem with infant industry assistance is that the assistance is only intended for a limited term but carries the innate problems of when to withdraw assistance and of retaining policy credibility when withdrawing assistance. For instance the ACT Minister for the Environment and Sustainable Development (Corbell 2011b) closed new applications for micro feed-in tariffs but successfully ensures policy credibility by honouring existing feed-in tariff agreements. However, Garnaut (2011, p. 15) discusses how those consumers receiving feed-in tariffs are being cross-subsidised by other consumers, which is economically inefficient. In agreement, Nelson, Simshauser and Kelly (2011) estimate the household impact of feed-in tariffs by income groupings and conclude that wealthier households are beneficiaries and the effective taxation rate for low income households is three times higher than that paid by the wealthiest households. So, there is a policy dilemma that is maintaining policy credibility perpetuates economic inefficiency and social inequity.

A resolution to this policy dilemma would be to maintain feed-in tariffs fixed permanently in nominal terms to those consumers contracted, so the influence of the agreed feed-in tariffs gradually fades out with time and are replaced by a more sustainable feed-in tariff regime.

In addition, developing a more sustainable economically neutral feed-in tariff provides a way to internalise the positive externality of deferred transmission and distribution investment for investors in embedded generation (Garnaut 2008, p. 452). However, there is debate over whether a feed-in tariff should be paid for the net or the gross contribution to the distribution grid. Farrell (2011, p. 33) discusses the major drawback of net metering, which is to optimize the size of a solar array for on-site load rather than maximise the solar array. The economic argument favours gross; this way the investor can make the decision to install the generators based on the contribution to the grid, so the feed-in tariff rate is based on the locational marginal price (LMP) to provide the right price signal for generation investment. AEMC (2011b) proposes LMP as one of five options in the transmission framework review. Under the gross payment method the householder would pay the retail rate for the total electricity consumed whether sourced from the grid or from their own generator to provide an incentive for the customer to conserve electricity and to provide a profit motive for the retailer. The charge for transmission and distributions costs need itemising on bills, as the customer does not use transmission or distributions to consume their own generated supply of electricity and to provide a price signal for the deferment in investment in transmission and distribution.

The NSW Auditor General (Achterstraat 2011) reviews the solar bonus scheme associated with the current gross feed-in tariff and discusses how prior to 2010 NSW had a net feed-in tariff. Additionally, the Auditor General recommends a review of the projected cost of the solar bonus scheme to answer the question of sustainability and recommends provision be made for an exit strategy. These changes or recommendations indicate that adaption is occurring in the right direction with the caveat that the solar bonus scheme is replaced with a sustainable gross feed-in tariff.

The Australian PV Association (APVA 2011) and Watt (2011b) discuss how solar PV has reached grid parity, that is electricity generated at the same price as coal plus transmission and distribution costs, but parity will be insufficient to ensure the appropriate economic level of household PV uptake because people suffer investment myopia over the returns from long term investments, such as, the 30-40 year life of a

PV unit. In agreement, Yates and Mendis (2009) and Williams (2011) discuss the sensitive of demand for solar PV installation to interest rates and to financing. A well-researched market failure of the retirement industry is investment myopia that has spurred government intervention in the form of superannuation using a complex array of policies including tax breaks for voluntary contributions and compulsory contributions. Similarly, the government intervenes to remedy a market failure in the provision of tertiary education to offer interest free student loans that provide equity and acknowledge the positive externalities of education. The solar PV industry also exhibits investment myopia, positive externalities and equity concerns.

Section 4.7 discusses Origin Energy's (2007) argument for interest free loans for efficient energy investment to address positive externalities and equity concerns. A similar argument can be made for interest free loans for solar PV. However, people usually pay for their solar PV or solar hot water heating installations by increasing their house mortgage. This is appropriate in the case of long term investments such as solar PV. This approach works for house owners but not for renters. The fact that proportionately more low income individuals rent houses goes some way to account for the highest (richest) quintile having twice the rate of solar PV installations compared with the lowest (poorest) quintile (Bell & Foster 2012). The low solar PV penetration in the lowest quintile is due to the dual problem of low income and rental accommodation. Trying to address this poverty trap with subsidised loans is insufficient. A solution is required that acknowledges the tenant-landlord relationship and the consequent misalignment of benefits and costs. Section 10.2.4 further discusses energy poverty.

Foster et al (2011, p. 2) discusses how solar PV has acknowledged potential to defer transmission investments, which are largely driven by peak demand. However, residential solar PV is insufficient and there is a requirement for significant commercial solar PV installation but unlike countries such as Germany and Spain, Australia has until recently very few incentives for commercial installations. Williams (2011) discuss the commoditisation of residential solar PV, which is evidence that the residential segment of the solar PV market has moved beyond infant industry status and beyond infant industry support requirements. Whereas the large and medium-scale solar PV segments are still in their infancy and still warrant direct infant industry support because the installation of medium and of large-scale solar PV requires a much higher degree of skill than residential solar PV.

In infant industry assistance, Corbell (2011a) announces the first feed-in tariff in Australia for large scale solar. The plan uses a feed-in tariff reverse auction for the two large scale solar generation plants capable of powering 7000 homes. The reverse auction appears a much more appropriate method to target an infant industry than the oversubscribed fixed micro feed-in tariff. The advantage of the reverse auction is that each time the auction is held the technology matures and the feed-in tariff becomes smaller, which provides an inexpensive way to maintain policy integrity and support infant industries. Additionally, the two issues of over subscription and of overly supporting an infant industry become redundant. This large scale feed-in tariff policy is a well-adapted approached to climate change compared to the micro feed-in tariffs policies.

IEA (2011c) and Renewable Energy Policy Network of the 21st Century (REN21 2011) provide a comparison of countries' feed-in tariffs. REN21 (2011, p. 52) notes that Australia, Canada and the US have only state or province feed-in tariff policies, which contrasts with all the other countries that have national feed-in tariff policies. Australia's fragmentation of policy by state induces inconsistency among feed-in tariffs providing a source of maladaptation. The Australian Minister for Climate Change (Wong 2008) discusses how a CoAG Working Group is considering harmonising state feed-in tariffs for solar and other renewable energy technologies where there is a proposal for the preparation of an options paper on a nationally consistent approach to feed-in tariffs. However a national policy has yet to appear.
REN21 (2011, p. 84) compares when various countries and states have adopted a feed-in tariff. The following list compares the adoption dates for the states in the NEM with South Korea.

- 2003 South Korea
- 2007 SA
- 2008 Qld
- 2009 ACT, NSW and VIC

This comparison shows that the NEM is institutionally slow at adapting to climate change measures compared to South Korea. Section 4.4 discusses using REN21's (2011, p. 84) international comparison of feed-in tariff adoption year as a climate change adoption performance indicator.

Furthermore, the NSW Independent Pricing and Regulatory Tribunal (IPART 2011) is calling for submissions on establishing a fair and reasonable feed-in tariffs for electricity generated by small-scale solar PV. In comparison, IEA (2011c, p. 37) discusses how South Korea is one of the first countries to supersede the feed-in tariff where the RPA (Renewable Portfolio Agreement) will replace the feed-in tariff scheme in 2012. Under the RPA, the government in conjunction with private enterprise plan to install 1.2 GW capacity of solar PV by the end of 2016. This RPA is another indicator that Australian institutions are slow at adapting to climate change.

9.2 Carbon pollution reduction scheme

The price signal from the carbon pollution reduction scheme (CPRS) is intended to transform the current portfolio of high CO_2 emissions generators in Australia in favour of a lower emissions portfolio. The CPRS starts with a carbon tax in July 2012, which converts to an emissions trading scheme (ETS) in July 2015. The CPRS has the following four sources of maladaptation to climate change:

1. CPRS supplanting RET;
2. ETS market failure;
3. trading carbon credits internationally; and
4. international corruption.

Regarding CPRS supplanting RET, Garnaut (2008, p. xxxii) states *"There are structural reasons to expect market failure in response to carbon pricing in relation to the*

information required for optimal use of known technologies; to research, development and commercialisation of new technologies; and to network infrastructure." Garnaut (2008, pp. 403-60) suggests using policies to directly address the stated failures that will also negate the need for the RET. However, under CPRS without RET gas generators can simply replace coal generators. This coal to gas transformation would fail to diversify Australia's portfolio of energy sources. Furthermore, CPRS in conjunction with RET ameliorates the effects of domestic corruption and political lobbying. Section 9.4 further discusses the RET.
Section 9.6 discusses Garnaut's (2008, p. xxxii) comments regarding network infrastructure market failure.

Regarding ETS market failure, Ellerman and Joskow (2008) discuss three market failures in the European Union (EU) ETS, being over allocation, price volatility and windfall profits for generators. Ellerman and Joskow (2008) consider these learning experiences, which can be overcome by using more accurate information, by allowing the banking of credits between compliance periods and by increasing the frequency of auctioning. Despite these learning experiences, Lewis (2011) reports on a further EU ETS collapse in carbon prices, which results from a combination of over allocation and the aftermath of the global financial crisis in Europe. The EU ETS provides Australia with many valuable lessons and shows that developing a robust ETS comes with many unforseen problems, so it is prudent to maintain the RET.

Regarding trading carbon credits internationally, Garnaut (2008) discusses how trading provides a mechanism to lower the overall costs to the world of the transformation to lower CO_2 emissions. However, this trading proposal has three major problems being, international corruption, losing government revenue, and losing a policy tool to promote renewable energy sources domestically.

In relation to international corruption, Transparency International (TI 2011) produces an international corruption perception index on 182 countries. Table 9-1 shows the 16 least corrupt countries where Australia is ranked 8^{th}. The index compiles the results form a number of surveys to allow basic statistical analysis. Since most of the world ranks as more corrupt than Australia, this does raise credibility issues over an international trade in carbon credits. For instance in the least corrupt country New Zealand (NZ), Stock (2011) reports on the NZ ETS experience in trading carbon credits internationally where the price for a NZ Unit (NZU) went from $22 in May 2011 to $11 in late November 2011. This halving in the price of a NZU was the result of NZ emitters' ability to import carbon credits. However Stock (2011) claims that some of the UN-backed Certified Emissions Reductions (CER) are of suspect validity and predicts that the New Zealand Government will substantially curtail the import of CER.

Table 9-1 International Corruption Perception Index for 2011

Country Rank	Country / Territory	CPI 2011 Score	Country Rank	Surveys Used	Standard Deviation	Range		90% confidence interval	
						Max	Min	Lower bound	Higher bound
1	New Zealand	9.5	1	9	0.05	9.7	9.1	9.4	9.5
2	Denmark	9.4	2	8	0.05	9.5	9.1	9.3	9.5
2	Finland	9.4	2	8	0.07	9.8	9.1	9.3	9.5
4	Sweden	9.3	4	9	0.08	9.7	8.9	9.2	9.4
5	Singapore	9.2	5	12	0.13	9.5	8.1	8.9	9.4
6	Norway	9.0	6	9	0.07	9.3	8.7	8.9	9.1
7	Netherlands	8.9	7	9	0.11	9.3	8.1	8.7	9.1
8	Australia	8.8	8	11	0.12	9.4	8.2	8.6	9.0
8	Switzerland	8.8	8	8	0.22	9.4	7.5	8.4	9.1
10	Canada	8.7	10	9	0.15	9.3	8.1	8.4	8.9
11	Luxembourg	8.5	11	8	0.25	9.1	7.1	8.1	8.9
12	Hong Kong	8.4	12	11	0.17	9.1	7.3	8.1	8.7
13	Iceland	8.3	13	8	0.27	9.5	7.1	7.8	8.7
14	Germany	8.0	14	10	0.18	9.1	7.1	7.8	8.4
14	Japan	8.0	14	12	0.27	9.1	5.7	7.6	8.5
16	Austria	7.8	16	10	0.24	8.9	6.7	7.4	8.2

(Source: TI 2011)

The credibility problem could be overcome by only allowing the buying of carbon credits from selected countries, such as the highly ranked countries in Table 9-1. However, the problems of losing government revenue and of dissipating CPRS's role to promote renewable generation still exist.

9.3 Mineral resource rent tax supplementing the CPRS

This section discusses how the mineral resource rent tax (MRRT) is necessary to supplement the CPRS as the CPRS fails to address or causes the following two maladaptations to climate change:

- exporting fossil fuels; and
- exporting the additional fossil fuels that CPRS will make uneconomical to burn in Australia

The CPRS will reduce the use of coal for electricity generation in Australia, which is effective for CO_2 emissions reduction in Australia. However this reduction in coal use means that more coal is available for export and unless every coal importing country has similar policy measures to Australia, then the Australian CPRS has only succeeded in switching the location of where the CO_2 is emitted. The switching problem is a maladaptation to climate change and is an unintended consequence of the NEM's adaption to climate change.

In addition to the switching problem there is the increasing use of coal overseas. For instance Bardsley (2011) reports on China's increase use of power and implementing renewable energy but there is also an overall increase in coal use. The amount of coal

Australia burns compared to the amount exported is trivial, so the Australian CPRS in isolation is really just tokenism.

Introducing the MRRT addresses the gap in the CPRS by helping coal importing countries moderate their use of coal and addressing the switching problem. The MRRT is a win for climate change but is also a win for Australia for the following five reasons:

- fossil fuels are finite;
- the temporary resource boom causes capital destruction in other more long term industries;
- MRRT is superior to resource royalties by maximising revenue from the economic rent;
- MRRT may moderate the more destructive mineral exploration, so protect the Australian environment; and
- the revenue from the MRRT provides funds for a sovereign or future fund or capital development.

Fossil fuels are a finite resource, which Shafiee and Topal (2009) estimate depletion time of 35, 107 and 37 years for oil, coal and gas respectively, so it is important for Australia to derive benefit by extracting the maximum economic rent from their sale over their short life. Shafiee and Topal's (2009) estimated depletion time for gas may have to be revised given the recent CSG discoveries. Additionally, many of the shareholders of resources companies are foreign, so the profits go overseas, which compounds the requirement to extract the maximum economic rent for Australia. In particular, China's managed exchange rate has enabled China to build up huge foreign reserves, which can be used to buy Australian resources companies, so China can obtain most of the economic rent. AAP (2011) reports on China's 'resource imperialism' as a risk for Australia and that the state of China is not playing by the same short term gains of the capitalist society and it is naïve to assume everything is fine. This sentiment is echoed in Burrell (2011) who quotes the Premier of Western Australia after the sale of Premier Coal to China *"From the state's point of view, the Premier Coal project is the major supplier of coal to the state-owned coal power stations, … That contract will continue, but we do have some concerns about security of supply and what this means for the long term."* A MRRT would help conserve and maintain mineral resources as a strategic asset.

The resources boom is causing a high and volatile exchange rate for Australia. According to traditional economic theory, the economy adjusts to the high exchange rate by people switching employment from declining areas of the economy, such as tourism and manufacturing, into the mining sector. However Keen (2011) discusses this simple switching of employment or economic restructuring as a free trade fallacy because there is an associated cost of the capital destruction in manufacturing and tourism, as the capital loses value and falls into disrepair. Furthermore Lamont (2011) comments that the economic restructuring could possibly be justified if mining was a permanent way of life but resource booms bust and mineral resources are finite. Lamont (2011) recommends the MRRT as a way to moderate exchange rate fluctuations and ameliorate the capital destruction effect in the manufacturing and tourism sectors.

An explanation of the prisoner's dilemma as a model of cooperation and conflict is introduced because the dilemma captures the cooperation and conflict aspects of the MRRT at both the interstate and international levels. The classic dilemma centres around two isolated unconvicted prisoners guilty of the same crime but the police are unable to convict either prisoner. If both prisoners remain silent, they both received relatively short sentences. If either prisoner confesses to convict the other prisoner, they walk free and the other prisoner receives a very long sentence. If they both confess to convict one another, both receive a medium sentence. Assuming a one off situation and that both prisoners behave selfishly, both prisoners confess to convict one another. But if the situation is repeated and the prisoners can communicate, the outcome would favour cooperation. The analogy between the prisoner's dilemma and MRRT is that cooperation between governments leads to higher revenue and selfishness between governments leads to poorer revenues but there is always the incentive to cheat on any MRRT agreement.

Henry (2009, p. xvii) considers tax on the following four items the most robust and efficient taxes:

- personal income;
- business income;
- private consumption; and
- economic rent from land and resources – (MRRT).

Henry (2009, p. xvii) recommends that resource royalties be replaced by the MRRT. In agreement, Verrender (2011) discusses how the state based royalty system is antiquated and inefficient and how inconsistencies in state and federal taxation cause investment misallocation and where investors can play one state off against another undermining taxation efforts. Additionally, Taylor (2011) discusses how the states undermine the Federal Governments tax revenue. Replacing the state based royalties and federal tax on minerals with a MRRT, which the state and Federal Governments could share, would help maximise tax revenue from economic rent and avoid these prisoner's dilemma scenarios. However, Henry (2009, p. xvii) concedes that the revenue from MRRT will be more volatile than from the existing resource royalties, which the MRRT will replace.

The resource boom has generated exploration of gas from new sources such as coal seam gas. For instance Roberts (2011) reports on a claim from Santos that the only way to meet the surge in demand for gas are unconventional methods such as coal seam gas extraction. But Klan (2011) discusses how the process of extracting coal seam gas damages the aquifers and uses a carcinogenic mixture of *benzene, toluene, ethyl-benzene and xylenes* (BTEX) to aid the cracking of the aquifers to release the gas in a process called fracking. Darling (2011b), the Queensland Minster of the Environment, discusses the results of an investigation into the carcinogenic contaminants formaldehyde and thiocyanate found in aquifers near a Kingaroy site using the coal seam gas extracting chemical where the contaminates were most likely the results of agricultural practices, as such, there is some uncertainty over the possible contamination that may be caused by coal seam gas extraction. A resource boom is short lived compared to the aquifers, which if left uncontaminated and managed could provide Australia with a permanent source of water and given the projected decreases in rainfall these aquifers become more important. The MRRT would moderate this extreme form of exploration, so help to preserve the aquifers and coal seam gas until a less toxic and damaging technique is developed to remove the gas. The ABC (2011b) reports on moves by the Western Australian Government to introduce legislation to require public disclosure of environmental management reports for fracking projects and the Queensland Minister of the Environment (Darling 2011a) announced a ban on BTEX, so there appears some adaption to moderate the potential harm from this process.

Norway and Chile are mineral resource rich countries that have successfully implemented a MRRT to provide reserves of foreign exchange in a sovereign or future fund. However, Hepworth (2011c) reports the second biggest mining company in the world called Vale is warning that new mining investments in Australia are at risk because of the CPRS and MRRT and alternative countries for investment will be sort. This situation is another prisoner's dilemma scenario where there is the potential for Australia to promote the MRRT internationally through an organisation of mineral exporting countries. An international MRRT would help moderate bubbles, CO_2 emissions and increase government revenues for mineral exporting countries.

9.4 Renewable energy targets

Table 6-1 shows the renewable energy targets (RET) that are the required GWh of renewable source electricity legislated by the Australian Government (2011) in the *Renewable Energy (Electricity) Act 2000.*

The objects of this Act are:

(a) to encourage the additional generation of electricity from renewable sources; and
(b) to reduce emissions of greenhouse gases in the electricity sector; and
(c) to ensure that renewable energy sources are ecologically sustainable.

This is done through the issuing of certificates for the generation of electricity using eligible renewable energy sources and requiring certain purchasers (called liable entities) to surrender a specified number of certificates for the electricity that they acquire during a year.

This section discusses each object of the RET legislation for sources of maladaptation in an order that aids clarity of argument.

Object (b) to reduce emissions of greenhouse gases in the electricity sector
Garnaut (2008, p. xxxii) states that *"No useful purpose is served by other policies that have as their rationale the reduction of emissions from sectors covered by the trading scheme [CPRS]. The Mandatory Renewable Energy Target should be phased out."* In an ideal world the phase out of RET is totally warranted but there are at least four considerations that make the use of two policy instruments to address one policy target necessary, being:

- market failure;
- corruption;
- political lobbying; and
- conflict of interest.

The previous section discusses the market failure of EU ETS and that Garnaut (2008, p. xxxii) expects market failure in Australia's response to carbon pricing due to structural problems. The RET would provide a backup policy to achieve carbon emissions reductions when the Australian ETS fails. Garnaut also proposes trading carbon emission abatements internationally. However, if Australia were importing carbon emission abatements from Europe right now, the failure of the European ETS would push down the price of imported carbon emission abatements, which would undermine Australian efforts to reduce carbon emissions and undermine support for developing electricity from renewable energy.

Furthermore, the previous section also discusses the experience of the NZ ETS and the corruption in the UN-backed CER, which would have similar consequences for an Australian ETS as the European ETS market failure described above. Again the RET provides a safety net for renewable energy generators and carbon emission abatement against ETS corruption or contagion from ETS market failure elsewhere.

In addition, Section 6.7 discusses the conflict of interest between state ownership of coal generators and private companies or individuals introducing renewable energy generators, particularly onshore wind generation. Parkinson (2011b) discusses Victorian legislation introduced to restrict new onshore wind generating capacity and block expansions of the interconnectors between SA and Victoria, which will prevent the flow of surplus electricity from SA's wind generators to the rest of the NEM. The RETs provide protection for renewable generators against such politically induced maladaptation.

The coal industry as a political lobby group has fought a long battle with the government over the introduction of the CPRS and MRRT. For instance Orr and Costar (2012) discuss the Australian Electoral Commission's slow disclosure of political lobbying and donations *"More successful were the big miners… The Mining Council of Australia reported $4 million and the Association of Mining Export Companies $2.2 million. But this was just the tail-end of the anti-mining tax campaign, the bulk of which (over $22 million more in advertising) had been spent in the previous financial year and helped bring down Rudd's prime ministership."* This slow disclosure is a flaw in the electoral process that undermines the democratic process and is a source of maladaptation to climate change. Orr and Costar (2012) call for a real time disclosure of political lobbying and donations via a publically accessible website among other measures to remedy the situation. These measures would address this source of maladaptation.

There is no doubt that the coal lobby group will try to water down the CPRS once the ETS is introduced. The mining industry has the wealth to instigate further national advertising campaigns against the CPRS and MRRT. The renewable energy sector is fragmented and small in comparison. The RET protects the renewable energy sector in case the coal lobby is successful in undermining the CPRS.

CoAG (2009) proposes a *"review of the operation of the RET scheme will be undertaken in 2014 to coincide with the review of the CPRS so that the review of RATE [RET-affected, trade-exposed] assistance can be conducted in parallel with the planned review of assistance for EITE [emissions-intensive, trade-exposed] industries."* This CoAG review of the RET and the CPRS is an area of policy uncertainty. Intense pressure from the coal industry could see the CPRS watered down and the RET expire, which would hamper the development of renewable generation.

Object (c) to ensure that renewable energy sources are ecologically sustainable

The CPRS in isolation would fail to meet this object for two reasons, the import of cheap carbon emission abatement credits and the substitution of gas for coal as a source of energy.

Object (a) to encourage the additional generation of electricity from renewable sources

This object uses the plural of source but so far the RET has reinforced the first mover advantage of onshore wind and solar PV generation. There lacks a mechanism to develop a portfolio of generator technologies and energy sources to reduce risk of supply. For instance, Ball et al. (2011) discuss how historically Australia's ample supply of coal has underpinned its power system but competing countries have used a variety of different energy sources and, as a result of this diversity, many have a more resilient power system to provide future electrical power.

However, given the policy uncertainty surrounding CPRS, the requirement for a broader portfolio of energy generation and the first mover advantage of onshore wind and small scale solar PV, a more selective RET that allocated targets to specific renewable energy generation and size would help reduce policy uncertainty and expand the portfolio of energy to better meet the original intent of the legislation '*to encourage the additional generation of electricity from renewable source**s***'.

For instance, a selective RET for solar thermal and large scale PV would help address the failure of the Solar Dawn Project and the Moree Solar Project to strike power purchase agreements, which are a necessary pre-requisite to obtain finance from the banks (Parkinson 2011a). A selective RET would require some coordination to ensure that the renewable energy generator could be commercial deployed.

Rather than using the RET, Garnaut (2008, p. xxiii) suggests addressing the expected market failure in carbon pricing with policies on research, development and commercialisation of new technologies. The Moree Solar and Solar Dawn Projects' failure to achieve a power purchase agreement show that the current research, development and commercialization policies are insufficient without a more selective RET based on energy technology and size. Additionally, there is a requirement to improve power purchases agreements (PPA) processes to finalise a project. Sections 12.3.1 and 12.3.2 further discuss RET and PPA, respectively.

9.5 Smart Grids

"A Smart Grid is an electricity network that can intelligently integrate the actions of all users connected to it - generators, consumers and those that do both – in order to efficiently deliver sustainable, economic and secure electricity supplies." (Smart Grids 2011)

This section discusses smart grids to provide climate change adaption indicators for use in section 4.4 to test a proposition regarding the institutional structure best suited to adapt to climate change. Smart Grid (2011) considers seven components comprise a smart grid:

- the smart grid;
- the smart house;
- renewable energy;
- consumer engagement;
- operations centres;
- distributed intelligence; and
- plug-in vehicles.

There is a need for a number of climate change adaption indicators to measure all seven components. Additionally, some of these components are dependent on another component, so a plan to manage the implementation of a smart grid is required. For instance the Korea Smart Grid Institute (KSGI 2011) manages the Korean government's smart grid road map shown in Table 9-2 and uses the interrelating components in its definition of a smart grid:

1) **Smart Power Grid**
Open power grids will be built to allow various kinds of interconnections between consumption and supply sources. The roll-out of such networks will pave the way for new business models, and the building of a power grid malfunction and automatic recovery system that will ensure a reliable and high quality power supply.

2) **Smart Consumer**
It aims to encourage consumers to save energy by using real-time information and producing smart home appliances that operate in response to electric utility rates.

3) **Smart Transportation**
It aims to build a nationwide charging infrastructure that will allow electric vehicles to be charged anywhere. It also establishes a V2G (Vehicle to Grid) system where the batteries of electric vehicles are charged during off-peak times while the resale of surplus electricity takes place during peak times.

4) **Smart Renewable**

It aims to build a smart renewable energy power generation complex across the nation by rolling out microgrids. This will ultimately lead to the emergence of houses, buildings, and villages which can achieve energy self-sufficiency through the deployment of small-scale renewable energy generation units in every end-user premise.

5) Smart Electricity Service

With the launch of a variety of energy-saving electricity rate plans, this service aims to improve consumers' right-to-choose by satisfying their different needs. In addition, it wants to deliver a wide array of added electricity services through the marriage of electricity and ICT, and to put in place real-time electricity trading system for the transactions of electricity and derivatives.

Table 9-2 South Korea's Smart Grid Roadmap

Implementation Directions by Phase	First Stage (2010~2012) 'Construction and operation of the Smart Grid Test-bed' (Technical validation)	Second Stage (2012~2020) 'Expansion into metropolitan areas' (Intelligent consumers)	Third Stage (2021~2030) 'Completion of a nationwide power grid' (Intelligent power grid)
Smart Power Grid	- Real-time power grid monitoring - Digital power transmission - Operate optimal distribution system	- Predict possible failures in power grids - Connect the power system with that of other countries - Connect the power delivery system with distributed generation and power storage devices	- Self-recovery of power grids - Operate an integrated energy Smart Grid
Smart Consumer	- Power management of intelligent homes - Various choices for consumers including rates	- Smart power management of buildings/factories - Encourage consumers' power production	- Zero energy homes/buildings
Smart Transportation	- Build & test electric vehicle charging facilities - Operate electric vehicles as a pilot project	- Expand electric vehicle charging facilities across the nation - Effective maintenance and management of electric vehicles	- Make the presence of charging facilities commonly available - Diversify charging methods - Utilize portable power storage devices
Smart Renewable	- Operate microgrids by connecting distributed generation, power storage devices and electric vehicles - Expanded utilization of power storage devices and distributed generation	- Optimal operation of the power system with microgrids - Expand the application of power storage devices	- Make renewable energy universally available
Smart Electricity Service	- Consumers' choice of electricity rates - Consumers' selling of renewable energy	- Promote transactions of electrical power derivatives - Implement real-time pricing system nationwide - Emergence of voluntary market participants	- Promote various types of electrical power transactions - Promote convergence for the market of electricity-based sectors - Lead the power market in Northeast Asia

(Source: KSGI 2011)

KSGI (2011) discusses a 'test-bed' funding of a total of 64.5 billion won, which will be invested between 2009 and 2013 on Jeju Island in the first stage of the roadmap. Jeju is located off the most southerly tip of Korea. Jeju offers isolations from the mainland grid and offers high levels of solar radiation and wind speeds to test the integration of renewable energy. Additionally, Jeju is a semi-autonomous region, so modifying legislation to accommodate smart grid technology is more readily achieved. Jeju had a population of 531,887 in 2005 and area of 1,848 km^2, so the test-bed is of significant dimensions. The second stage of the roadmap is a rollout of smart grid technology to the mainland's metropolitan areas and the third stage to the remainder of South Korea. The monopoly ownership of both transmission and distribution by the Korean Electric Power Company (KEPCO) allows an easily coordinated deployment of smart grid technology. Korea is leading the world in an integrated approach to deployment of smart grid technology. A report by KSGI on the first stage of the deployment is due out in May 2013 in the Korean language.

The International Energy Agency (IEA 2011b) also recognises the importance of energy efficiency, decentralised energy or distributed generation, renewable heat and thermal storage (BLUE Map scenario) to improve demand flexibility, while real-time pricing and dynamic communication with smart energy networks to accommodate an increased share of intermittent renewable electricity, helping to reduce the need for expensive electricity storage.

Seoul and South Korea are also good examples of decentralised energy and innovation. For example, the Seoul Metropolitan decentralised energy network is the third largest decentralised energy network in the world supplying electricity and thermal heating and cooling to more than 1 million households and nearly 2,000 customers of commercial and public buildings across a 1,500km network. Innovation includes the development of double lift heat fired absorption chillers using the district heating network and the utilisation of LNG.

Italy is the world leader in deployment of smart meters, where the former state owned monopoly utility called *E*nte *N*azionale per l'*E*nergia e*L*ettrica (Enel 2011) deployed 33 million smart meters over a five year period from 2001.

However more recently in Australia, the Prime Minister et al. (Gillard et al. 2010) announced a $100 million funding agreement for the 'Smart Grid, Smart City' program. The CSIRO (2010a) discuss how 'Smart Grid, Smart City' *"will deploy a live, integrated, commercial size smart grid in the Newcastle area, with parts of the trial also conducted in Newington, Sydney's central business district (CBD), Ku-ring-gai and Scone, NSW"*. The results of this test bed will be available to other electricity companies to enable a piecemeal national rollout of smart grid technology. Smart Grid Australia (SGA 2011) discusses the importance of R&D conducted in parallel with these test installations to better inform the national rollout.

The following section further discusses the relationship between monopoly ownership and climate change performance outcomes. Smart Grid (2011) and KSGI (2011) in Table 9-2 provide a list of potential climate change adaption indicators, which section 4.4 further discusses. Potential indicators include:

- roadmap;
- real time power grid monitoring;
- digital power transmission;
- smart meters and home management systems;
- smart appliances;

- consumer choice over dynamic pricing;
- plug-in electric vehicles and infrastructure;
- power storage;
- renewable energy penetration and integration;
- home power generation / Feed-in tariffs;
- consumer engagement / time of use programs;
- self-healing grid; and
- improving visualisation of grid and sharing of information.

9.6 Institutional complexity and the NEM grid as a natural monopoly

Chapters 4 and 6 find institutional fragmentation induced maladaptation to climate change particularly present in transmission and distribution. The more detailed analysis in the previous sections finds that fragmentation induced maladaptation is apparent in the feed-in tariff, CPRS with MRRT and smart grid. These three sources of fragmentation induced maladaptation contribute directly or indirectly to maladaptation of the transmission and distribution networks.

Regarding political fragmentation, REN21 (2011, p. 52) groups Australia, Canada and the US together as unique amongst other countries in their response to climate change being state or province based rather than national. Section 2.3 also discusses state based ownership of transmission and distribution as a cause of fragmentation maladaptation. This fragmentation induced maladaptation becomes apparent when facing a major challenge such as adaption to climate change, which requires numerous simultaneous changes to the grid to accommodate renewables and smart grid technologies. For instance the California Energy Commission (CEC 2009, p. 5) states *"major regional transmission projects that involve multiple jurisdictions and utilities and are needed for integrating remote resources, reducing costs, improving market operations, providing long term strategic benefits and improving operating flexibility, don't have a clear path forward."* As, simultaneously coordinating changes across a grid, can affect all the owners in different ways, then meeting the vested interest of multiple owners quickly becomes an intractable problem. Garnaut (2008, p. 446) describes transmission as a market failure requiring attention. AEMC (2011b, p. iv) proposes a single national co-ordinating transmission network service provider (TNSP) to manage the planning of all transmission assets in the NEM and a NEM wide transmission business to manage locational marginal pricing for generators (AEMC 2011b, pp. iii-iv). These two companies could partially address the fragmentation maladaptation by transforming the NEM's transmission into a pseudo monopoly. However the proposal adds yet another two companies operating in NEM adding to the complexity. Garnaut (2008, p. 446) discuss the public good aspects of interconnectors.

- Public goods—Infrastructure that is a pure public good (that is, non-rival and non-excludable) may be underprovided because the infrastructure provider is unable to capture the full benefits of its investment.

- Natural monopoly—Where infrastructure is best provided by a single firm, the firm may, without competition or regulation, underprovide and overcharge for use of the infrastructure.

The whole of the transmission and distribution in Korea is treated as a public good and forms a single natural monopoly called KEPCO, but KEPCO also owns most of the generation in Korea, which is not a natural monopoly. As discussed, Korea's response to climate change has been much faster than Australia, so the proposition that Australia's slow response is caused by institutional fragmentation will be discussed further in section 4.4.

What follows is a comparison between the Korean and Australian transmission and distribution. Table 9-3 shows the size of the Korean transmission system with a total transmission length of 30,676 km operated by KEPCO. In comparison six transmission companies in the NEM operate just over 40,000 km of transmission (Grid Australia 2011). In addition the NEM also has some privately owned interconnectors.

Table 9-3 Size of the South Korean transmission system

Branches	Line length (km)			Supports (unit)		
	Overhead	Underground	Total	Steel towers	Other	Total
765 kV	835	0	835	902	0	902
345 kV	8,326	254	8,580	11,176	13	11,189
154 kV	18,249	2,528	20,777	26,703	406	27,109
66 kV	252	1	253	610	384	994
180 kV HVDC	29	202	231	0	617	617
Total	27,691	2,985	30,676	39,391	1,420	40,811

(Source: KEPCO 2011 Transmission)

Table 9-4 shows the size of the Korean distribution system with a total line length of 428,259 km in 2010. Business Wire (2010) reports that KEPCO is South Korea's sole power distributor, serving 13 million households.

Table 9-4 Size of the South Korean distribution system

Year	Length (km)	Transformers	Supports
2010	428,259	101,692	8,343
2009	420,257	99,629	8,218
2008	410,014	96,865	8,052
2007	401,485	92,964	7,895
2006	393,304	88,266	7,608

(Source: KEPCO 2011 Distribution)

In comparison the NEM serves 8 million end users (AEMO 2011g) with thirteen distribution companies as shown in Table 9-5.

Table 9-5 Distribution and transmission companies operating in the NEM

State	Distribution Companies	Transmission Companies
NSW	3	2
VIC	5	1
QLD	2	1
SA	1	1
TAS	1	1
ACT	1	0
Total	**13**	**6**

(Source: EUAA 2011)

Furthermore, Australia, Canada and the US have state or province base policy responses to climate change (REN21 2011, p. 52), which provides these counties with similar institutional fragmentation problems. Table 9-6 compares the electricity consumption and production in kWh and GDP for Australia, Canada, US and South Korea. GDP is given in purchasing power parity (PPP) equivalent in millions of US dollars.

Table 9-6 International fragmentation comparison - raw data

Raw data	Australia	Canada	US	South Korea
Consumption (GWh)	225,400	549,500	3,741,000	402,000
Production (GWh)	232,000	604,400	3,953,000	417,300
GDP (PPP US$ millions)	882,400	1,330,000	14,660,000	1,459,000
States or Provinces	8	13	51	1

(Source: CIA 2011)

Table 9-7 is the electricity consumption and production and GDP in Table 9-6 divided by the number of political entities in the country that is state, province or territory.

Table 9-7 International fragmentation comparison per political entity

Per political entity	Australia	Canada	US	South Korea
Consumption (GWh)	28,175	42,269	73,353	402,000
Production (GWh)	29,000	46,492	77,510	417,300
GDP (PPP US$ millions)	110,300	102,308	287,451	1,459,000

Table 9-7 shows that Australia has the smallest amount of power administered by a political entity, which means even in comparison with the other fragmented countries, Australia has more political overhead per unit of electricity consumed or produced. As for GDP per political entity, Australia and Canada appear comparable in that each political entity administers about one third the GDP per political entity in the US. This high political overhead per unit of electricity and low GDP per political entity corresponds with the slow response to climate change for each political entity in Australia. Australia is the most fragmented of the fragmented group of three countries, where there is duplication of effort over relatively little electricity with relatively few resources.

These fragmentation or coordination and planning problems in NEM are recognised by the MCE and by the establishment of the AEMO and AEMC and the numerous reports addressing coordination problems. However, the AEMC (2010) role is *"to be the rule maker for national energy markets … [AEMC's] key responsibilities are to consider rule change proposals, conduct energy market reviews and provide policy advice"* AEMC (2009, p. viii) comments on their terms of reference *"MCE does not anticipate that this review will result in fundamental revision of market design …"*. So, recommending a rationalisation and amalgamation of the ownership of transmission and distribution would be beyond the scope of the AEMC's brief. Hence, there appears no obvious mechanism in Australia to achieve the rationalisation that has occurred in South Korea to transmission and distribution, which was the product of the Japanese occupation followed by a series of military dictatorships. In contrast each state within Australia in isolation developed transmission and distribution systems, which were natural monopolies. However these once independent systems are now linked producing one natural monopoly with multiple owners. In agreement, Stevens (2008, p. 24) recognises that there are strategic national planning problems to meet climate change due to the diverse ownership, particularly in the electricity sector, which may require government intervention to achieve desired outcomes. For instance, South East Queensland Water (SEQWater 2011) and SEQ Water Grid (2011) provide an example of government intervention promoting rationalisation following the linking of once independent natural monopolies.

Following the water reforms, the Queensland Minister for Energy and Water (Robertson 2011a) discusses the approval of a new Workforce Framework to protect the rights of staff being moved between councils and SEQ distributor-retailers. The framework's principles reassured workers that labour savings was not the driver for the SEQ water reforms. The framework protects the rights of workers for three years. This sort of measure is an important consideration when the word rationalisation is mentioned as people fear the loss of their jobs. This fear would be a source of maladaptation to climate change pending any rationalisation.

In addition the National Broadband Network (NBN 2011) provides an example of a government lead initiative of a natural monopoly to transform Australia's copper telecommunications network into fibre optics. This transformation would become far more logistically challenging if the telecommunications network had a similar fragmented ownership pattern to the NEM. The NEM will undergo similar transformations with the introduction of smart grid technologies, such as real-time measurement and smart metering where both projects would benefit from monopoly purchasing power and reduced coordination costs. Both these technologies can defer investment in transmission and distribution. Smart Grid Australia (2011) suggests that the NBN also provides the means to deliver aspects of smart grid technology.

The use of distributed generation within a smart grid can defer investment in transmission and distribution. To accommodate distributed generation, the NEM is undergoing a transformation from the traditional unidirectional generator-transmission-distribution-consumer model to a distributed and bidirectional model, where a combined transmission and distribution monopoly is better placed to coordinate the transformation. For instance the Korean Smart Grid Institute (2011) discusses Korea's smart grid road map with near completion of the test bed in Jeju Island and with an expected national rollout starting in 2012 for completion in 2030. KEPCO's monopoly transmission and distribution is well suited to accommodate this transformation.

In a further source of maladaptation, Garnaut (2008, p. 452) discusses how the revenue of a distribution businesses is calculated on the value of the asset base, which creates the incentive to build more distribution infrastructure. So, promoting distributed energy is in direct conflict with this arrangement. In agreement, Hepworth (2011b) reports on an Energy Users Association of Australia (EUAA 2011) report, which claims a systematic bias towards inflated forecasts of the capital and operating spending when their tariffs were set. Furthermore, Hepworth (2011b) reports that the most costly increase in consumer electricity bills are in transmission and fossil fuel costs. Hepworth (2011b) reports the Chairman of the Australian Energy Regulator (AER) Andrew Reeve saying how the rules governing the charging for electricity networks had to change.

Regarding an impediment to the NEM adapting to climate change, the traditional role of mergers and acquisitions to enforce capital discipline and rationalise the market is lacking in the NEM's transmission and distribution as the majority of transmission and distribution is held by state owned companies. In contrast, David (2011) discusses acquisition of privately owned transmission companies in the Philippines. The National Grid Corporation of the Philippines (NGCP) has petitioned the Energy Regulatory Commission (ERC) to buy the transmission assets of the Cebu Energy Development Corporation (CEDC) for provisional approval authorising NGCP to acquire the assets of CEDC. However, state ownership in Australia acts as an impediment to this form of rationalisation, so rationalisation would require political inspiration.

In another conflict of interest to defer transmission investment by the introduction of distributed generation is the state ownership of the coal generators where attaching distributed energy to the grid only provides competition for the coal generators. For instance Parkinson (2011b) discusses legislative moves in Victoria to block further onshore wind generation and an interconnector expansion between SA and VIC.

Under the current framework, the AEMC (2009, p. vi) discusses the lack of appropriate mechanism to address the addition of cluster of generators in geographic remote locations where these clusters are primarily onshore wind generation encouraged by the RET. Garnaut (2008, p. 448) also discusses the cluster problem and associated free rider problem. Adopting a monopoly transmission and distribution company would fail to completely solve this cluster problem but does significantly reduce the complexity of the problem.

AEMC (2009, p. vi) expects that the expanded RET and to a lesser extent the CPRS will fundamentally change the utilisation of the network over time both between regions and within regions. These expanded changes to flows are likely to put pressure on the existing framework governing transmission and distribution (AEMC 2009, p. vii). So, AEMC recommends a local price signal for generators adjusted for congestion, as the locational price signal will lead to more efficient decisions. The AEMC (2011b, p. iv) proposal for a single national co-ordinating TNSP to manage transmission planning and a NEM wide transmission business to manage locational marginal pricing for generators (AEMC 2011b, pp. iii-iv) is as close as the AEMC could come within their terms of reference to recommending monopoly ownership of transmission grid.

9.7 Privatisation induced maladaptation and alternatives

This section discusses (DRET 2011a) white paper calling on the privatisation of state owned energy companies. The privatisation of state owned enterprises (SOEs) has potential for maladaptation to climate change in the following ways:

- importing culturally insensitive CEOs to cover the perceived shortage of Australian CEOs to manage the newly privatised energy companies;
- the change in focus from the three-year election cycle to a quarterly business reporting cycle;
- the failure to address fragmentation of a natural monopoly;
- being offered one policy option when there are alternatives to the simple false dichotomy of either state ownership or private ownership;
- selling assets at the tail end of the global financial crisis is poor timing;
- privatised coal generators requiring subsidies to shut down;
- increasing the complexity of smart meter deployment; and
- confusing retail customer churning for market efficiency.

The culturally insensitivity of non-Australian CEOs controlling large natural monopolies is a potential source of maladaptation for the NEM. For instance Oakes (2009) interviews the new CEO of Telstra, David Thodey, about the previous US imported CEO Sol Trujillo. During Trujillo's tenure about $25 billion was wiped from Telstra's market value and customer complaints increased by 300%. News (2007) reports the then Prime Minister John Howard complaining about Trujilo's 30% pay increase of $11 million being an abuse of the capitalist system. Natural monopolies are vulnerable to such abuse and there is little need for restraint for Trujillo with no long term vested interest in Australia's well-being. Additionally, Trujillo was constantly in conflict with the political leaders of Australia over a wide range of issues. In contrast the current Australian CEO's of the NBN and Telstra, Michael Quigley and Thodey just quietly and diplomatically go about their business.

The change from state ownership with a three year election cycle to the free market with quarterly reporting periods promotes short-termism in the energy sector where assets have a life of 40 years or more. The White Paper also claims that private companies are more innovative as a reason for privatisation. The inventiveness and short-termism of the free market is exemplified by Enron who invented numerous techniques to improve quarterly results. Enron was audited by Arthur Anderson who provided Enron with a clean bill of health shortly before Enron's bankruptcy. Given Australia's relative lack of corruption shown in Table 9-1 and lack of experience in dealing with people from such a business culture, there is cause to seriously doubt a role for foreign citizens managing Australia's energy assets or a requirement for a raft of audit legislation to contain inappropriate behaviour.

Additionally, the transfer of ownership from state to private sector fails to address the issue of fragmentation in the NEM, in particular the natural monopoly that is the NEM grid. However, there is the remote possibility of mergers and acquisitions resulting in a single holding company for transmission and distribution but this rationalisation process would be very torturous and wasteful. For instance following Telstra's privatisation and leadership by Trujillo, the retail and network arms of Telstra are being separated to form the NBN and Telstra retail. This experiment in privatisation of a combined network and a retail business provides a tortured and wasteful route to rationalisation of the network as a natural monopoly under government control and the retail business in the private sector.

Furthermore, the White Paper also offers a false dichotomy of either private ownership or state ownership. Banks (2009) calls for policy based on evidence and for policy advice to offer alternatives to help prevent ideology informing policy. There are alternatives to this dichotomy. For instance KEPCO is 51% owned by the South Korean government and the reminder in private hands. This split ownership allows KEPCO to more readily raise capital, which is one of the reasons suggested for privatisation. KEPCO is a world leader in innovation, so the White Paper's innovation argument for 100% privatisation is weak. Another alternative is state and Federal Governments maintain 51% joint ownership of a company that owns all transmission and distribution in the NEM to address fragmentation and fully privatise all generation and retail assets to address conflict of interest issues. There are alternatives to total privatisation that would better address fragmentation and conflict of interest and would be less susceptible to free market failures like Enron. Section 4.4.1 discusses a research question to test the adaption performance of alternative economic structures to climate change.

Selling assets at the tail end of the GFC is poor timing for two reasons:

- the credit contraction reducing the saleable value of the assets; and

- the uncertain economic conditions warranting a discount on the value of the assets.

This uncertainty discount or risk premium induced by the GFC is compounded by the forthcoming introduction of the ETS. This credit contraction and risk premium could be avoided by selling the assets after the global recovery from the GFC and after the ETS establishes some stability.

However, the following issue remains for privatised coal generators. Namely, members of the ageing fleet of coal generators will eventually become uneconomic to run once the ETS comes into effect when the Federal Government will come under pressure to offer compensation, as is currently the case with the brown coal generators in Victoria. This scenario undermines posited gains from privatising the coal generators. Other than reducing conflict of interest to grid access, the gains from privatisation are marginal because the NEM trades via a gross pool market, so coal generators are already subject to an essential feature of market discipline. Government compensation to privatised coal generators to shut down due to the CPRS remains a vex issue.

Furthermore, the introduction of in-house-display equipped smart meters and of dynamic pricing will have a large impact on ameliorating peak demand. The issue over whether retail is privatised detracts from the national roll out of smart meters and the introduction of dynamic pricing. The privatisation of retail and customer churning makes a systematic roll out of smart meters more challenging as the benefits from smart meters are spread amongst four stakeholders: the customer, retailer, distribution operator and transmission operator (WEC 2010). Due to customer churning, the retailers are unable to guarantee returns from the smart meter installations, so installation is usually organised by the distribution operator. However, the stakeholder organising the roll out will determine a suite of smart meter features that benefits itself, leaving out desirable features that benefit the other stakeholders. For instance the roll out of smart meters in Victoria was organised by the distribution operators where the feedback advantages of the smart meters was promulgated to the public to smooth the way for the installations but the in-house-displays became an optional extra to be purchased by the customer. This caused an adverse customer reaction who felt misguided by the distributors. There is a requirement for careful evaluation of smart meter features to ensure that all stakeholders benefit from installation.

Additionally, there is confusion in the literature between retail customer churning and market efficiency. Any relationship between churning and market efficiency will be modest unless the customer has all the available pricing options presented in an unbiased way that can be readily compared. Hence the retail market requires design to ameliorate information asymmetry to harness the full benefit for the customer. A website comparing all the retail pricing options and the ability to swap retail provider on the website would go some way to meeting these requirements. Additionally, an opt-in rather than an opt-out clause for door-to-door sales would reduce biased presentations and reduce unnecessary churning. Sections 3.1 and 3.2 further discuss privatisation of retail and generation and the introduction of smart meters and dynamic pricing, respectively.

9.8 Further criticisms of the CPRS

Chapter 7 discusses how incentives for renewable energy should be structured to engender a robust secure energy infrastructure that will eventually lead to a high penetration of non-intermittent renewable energy infrastructure resilient and adaptable to climate change. This will need to combine the benefits of decentralised energy, centralised energy, renewable electricity, renewable gas and renewable heat infrastructure rather than electricity infrastructure alone with all of its intendant problems going forward into the 21st century.

The current structure of the CPRS will not deliver the desired results above in isolation as discussed in Sections 10.2 and 10.4. Further arguments against the CPRS are the lack of transparent to consumers as it applies to the wholesale price of electricity and so attaches a carbon cost to all forms of energy generation including low carbon natural gas and zero carbon renewable energy. This implies that generators are not really incentivised to reduce their emissions as they can simply pass on the costs through the wholesale market, as their competitors do. This argument is only partially valid. It is true that the CPRS lack transparency as it acts through the market. However, alter the introduction of the CPRS fossil fuel generators have an additional cost to non-fossil generator. This cost imposition relatively incentivises renewable energy and disincentives fossil generators.

Regarding lack of transparency, consumers cannot see the carbon tax on their energy bills so there is no driver or incentive for consumers to implement energy efficiency to switch to lower carbon fuels or generate their own energy. The argument against this lack of transparency is that the carbon price signal contains all the information required to make the optimal decision. However, there are well documented biases that show that people are imperfect optimisers (Bell 2009 sec. 2.1.3.3). Additionally, people have bounded rationality (Simon 1972), so it is perfectly rational to use rule-of-thumb. Tisdell (2013) discusses the implications of bounded rationality within the electricity industry.

As previously discussed, the CPRS is definitely not a standalone solution. The transparency issue is just one more reason to consider compliments to the CRPS, such as, those taken in UK and Germany.

9.9 Further alternatives or compliments to the CPRS

This section describes UK and German schemes that are used in addition to the European CPRS. The section also discusses criticisms of these schemes.

9.9.1 Climate Change Levy in the UK

The Climate Change Levy (CCL) (HMRC 2013) introduced by the Labour Government in the UK in 2001 and extended by the incoming Conservative led Coalition Government to 2023. The CCL applies to non-domestic energy users but was fiscal neutral in that the cost of the CCL was offset by a 0.3% employer's rate reduction in National Insurance contributions. The residential and transport sectors are exempt from the CCL as are good quality combined heat and power (CHP) and renewable energy.

A reduction of up to 65% (originally 80% on start-up of the CCL) from the CCL may be gained by energy-intensive users provided they sign a Climate Change Agreement which commits the user to specified energy or carbon reduction targets within a specified time period (typically 5 years) which are agreed between the Government and each industry sector having regard to the nature and type of use of energy for each industry sector.

As the CCL is shown on energy bills this also provides a transparent incentive for consumers to implement energy efficiency and switch to CHP and/or renewable energy. Energy companies and a new breed of Energy Services Companies (ESCOs) were also incentivised to provide and finance a wide range of energy services to reduce greenhouse gas emissions.

This funding mechanism for CCL is flawed because it effectively acts as a tax on the poorer households to subsidise the richer households to install energy efficiency equipment. This situation is compound by the link between poorer people being more likely to be in rental accommodation and there lacks incentive for landlord to install energy efficiency equipment. A similar situation is analysed within an Australian context in Bell and Foster (2012) regarding the installation of solar PV and the residential solar PV feed-in tariff. The findings are the requirement for incentive for landlords to install solar PV and a method to split the benefits of the installation between the landlord and the tenant. In contrast, homeowners can and do extend their mortgages to install such equipment. It must be recognised that in the long term installation of solar PV or energy efficiency equipment will benefit everyone by moderating future electricity price rises but the CCL and Australian solar feed-in tariffs are a regressive way to achieve this goal.

9.9.2 Renewable Energy Sources Act in Germany

An alternative approach to reducing emissions and moving towards a renewable energy future is Germany's Renewable Energy Sources Act (EEG). This act became law in 2000 and was amended in 2004, 2009 and 2012. In 2011, around 17% of electricity, 8% of heat and 6% of fuel used in Germany was generated from renewable sources. The 2012 Act set a target to increase the share of renewable energy to 40% by 2020 and to 80% by 2050 with similar targets for greenhouse gas emission reductions.

The three main principles of the EEG are:

- investment protection through guaranteed feed-in tariffs and connection requirements;
- no charge to Germany's public purse; and
- innovation by falling feed-in tariffs (degression of 1% a year)

The innovation by falling feed-in tariff is intended to exert cost pressure on manufacturers leading to technologies becoming more efficient and less costly.

Another outcome of the EEG is to move Germany away from fossil and nuclear fuels and centralised electricity infrastructure towards renewable energy sources and a decentralised electricity infrastructure, taking advantage of decentralised thermal energy networks and renewable gases. The decentralised energy approach generates greater economic benefits than the cost of the EEG through avoided grid network investment and charges and other savings such as reduced environmental impacts and related economic benefits. According to a European Commission study, the net benefit of the EEG exceeds the additional costs of initial investment by 3.2 billion Euros. In addition, the EEG generates more competition, more jobs and more rapid deployment for manufacturing.

Germany now has one of the most expensive domestic electricity prices in world. This situation begs for a more cost effective approach. The EEG has the innate problem of using a calculated feed-in tariff rather than use a more cost effective market determines feed-in tariff. Large scale and residential scale renewable energy requires different methods to develop a market determined feed-in tariff.

Wood and Muller (2012) provide a comprehensive discussion of the use of a feed-in tariff reverse auction for large scale solar PV capacity. A reverse auction involves would-be sellers making lower bids to undercut other bidders to provide a good or service to a buyer. This approach is well suited to developing a portfolio of renewable energy, as discussed in Section 6.12. However, feed-in tariff reverse auctions are unsuitable for small scale solar PV for three reasons: inequity; the transaction costs involved for numerous participants in the auctions; and the logistical cost of maintaining numerous feed-in tariff rates.

Bell and Foster (2012) discuss a market determined feed-in tariff to promote the spread of solar PV and other small scale renewables in the residential sector. Where there is a requirement to establish price signals to enable DSM, such as, the introduction of TOU billing and TOS payments for non-scheduled generators. Together TOU and TOS payments provide appropriate price signals for the diffusion of energy storage technologies, such as batteries, into the NEM. The eventual deployment of EVs, with their large battery storage, could aid DSM if the appropriate TOU and TOS price signals are in place. Without these price signals, EVs will exacerbate the existing peak demand problem in the NEM.

10. DISCUSSION

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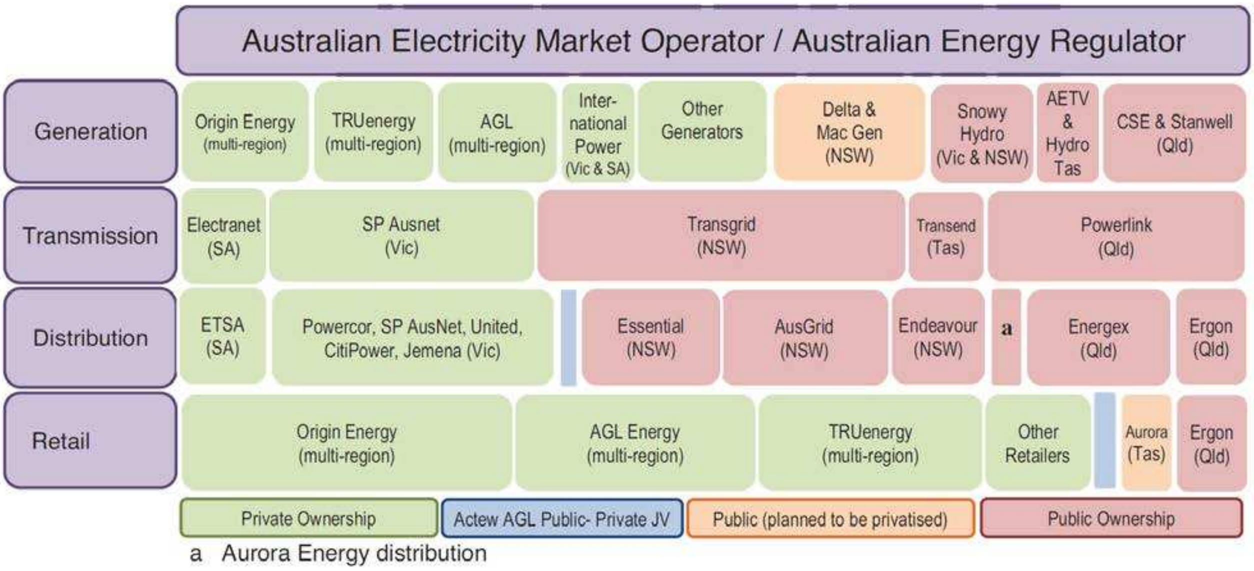
In this chapter we make recommendations that address the four sources of maladaptations to climate change:

1. institutional fragmentation, both economically and politically;
2. distorted transmission and distribution investment deferment mechanisms;
3. lacking mechanisms to develop a diversified energy portfolio; and
4. failure to model and to treat the NEM as a national node based entity rather than state based.

The recommendations that address the four maladaptations are interdependent but the issues are discussed in turn for clarity of exposition. This also makes it easier to relate to the non-technical summary designed for policy makers in the Preface. Detailed justification for the recommendations is provided in the previous chapters.

Figure 10-1 provides an overview of the ownership patterns in the NEM by indicative share. This diagram informs the discussion of the four sources of maladaptation to climate change in this section.

Figure 10-1 Ownership patterns in the NEM by indicative market share



(Source: QCA 20013)

Transmission and distribution constitute a natural monopoly. In contrast, retail and generation are more competitive. However, there is a high degree of fragmentation in transmission and distribution as there are 14 transmission and distribution companies listed. The consequences are increased coordination costs and lack of economy of scale savings, creating unnecessary costs for customers. In contrast, retail is largely owned by three companies Origin Energy, AGL Energy and TRUenergy, which indicates that competition in the retail market is weak. The consequence is that retailers can exercise market power to obtain higher profits. The generation market has eight more or less evenly sized companies and a number of other smaller generator companies. This spread indicates generation companies are less able to exercise market power to obtain higher profits. However, the three big retailers Origin Energy, AGL Energy and TRUenergy also own a sizable part of generation, which can undermine competition in the generation sector. This situation is analogous to Coles and Woolworths introducing their home brands that stymie competition from other suppliers.

What is the likely future structure for the retail and generation sectors if the remainder of the retail and generation sectors are privatised? How will this new structure help or hinder addressing the four sources of maladaptations to climate change? In Section 9.7 we discussed how the majority of residential customers are reluctant to change retailer with only a small number of customers engaged in active churning. This situation makes it difficult for new retailers to make headway in the market and makes the three large incumbent fairly immune from competition. Barring intervention from the ACCC, the big three retailers are likely to gradually absorb or by-out the remaining small retailers. A similar story is playing out with Coles and Woolworths buying out the alcohol franchises and chain stores. The big three retailers can use their influence in the generation sector to expand their presence. A similar situation is playing out with Coles and Woolworths in developing their home brands. The long term prognosis is that the big three retailers will also become the big three generation companies. High market share allows greater market power to gain higher profits, which come at the expense of cheaper electricity for customers. The management of the big three will be rewarded handsomely for creating such high profits in a supposedly “competitive” environment. The aim of the private sector is to maximize profits. This usually entails selling more electricity, which is at odds with adaptation to climate change.

Regarding the privatisation of distribution and transmission, management in the private sector can attract a premium over payments in the public sector partially for working in a competitive environment. However, the NSPs are natural monopolies, so they do not warrant this private sector premium. The privatisation of networks leads to increases in profits by reducing the number of employees and maintenance of the network. Examples include the privatisation of the UK railway and the Auckland CBD electricity network. Additionally, building more networks and providing more network service to increase profitability is at odds with adaptation to climate change. The privatisation of the NSP only delivers savings by increasing the risk of discontinuity of service and misses the greatest potential to save on costs for customers, as discussed in Section 10.1.

In summary, the electricity industry needs a new business model that can both contain costs for customers and address climate change. There is the further requirement that the business model be capable of coordinating an extraordinary amount of technological change.

10.1 Institutional fragmentation, both economically and politically

The NEM is extremely fragmented, both economically and politically, which continues to hinder the NEM's adaptation to climate change. To address political fragmentation, the recommended solution is that the States cede legislative power to the Federal Government over matters pertaining to the NEM. To address economic fragmentation, the recommended solution is to transfer the ownership of all transmission and distribution in the NEM into a single holding company owned by the States, Federal Government and privately. This produces an alignment between a single company owning the infrastructure and the NEM's transmission and distribution being a natural monopoly. The Federal Government maintains a controlling minimum stake of 51% in the monopoly. This minimum stake would address the conflict of interest between State Governments and private entities connecting to the NEM grid. The conflict of interest resolution would also extend to the retail sector. This solution is currently used in South Korea where a single company runs both electricity transmission and distribution for a population of 50 million people. In Section 9.6 we discussed the NEM's political and economic fragmentation in detail and provided further justification for the above solution.

Additionally, the predicted increase in extreme weather provides further justification for a single company holding all distribution and transmission infrastructure. The larger capital base and geographic spread of such a company would allow better internal risk management and resultant cost savings for the customer. In Sections 2.11, 3.3 and 5.4 we discussed risk management and extreme weather events in more detail. This risk management solution helps mitigate risk. However transmission and distribution remains inherently at risk to climate change and severe weather events.

So, there is a requirement to consider the electricity infrastructure in coordination with other energy infrastructure to improve both resilience and energy efficiency. Rather than rely solely on electricity transmission and distribution, there is an energy transfer option available that simply by-passes electricity transmission and distribution by using the gas infrastructure. In Section 6.10.2, we discussed the role of power-to-gas and tri-generation technologies. The power-to-gas technology can remedy both the intermittency and dispatchability problems associated with non-hydro renewable energy sources because the gas infrastructure can act very effectively as an energy storage device. This power-to-gas process is reputed by some to be more energy efficient than batteries. Plus, gas pipelines have a relatively low energy loss compared to electrical transmission and distribution lines to deliver gas for tri-generation. Finally, tri-generation allows for the generation of electricity in situ where the waste heat is used for heating and cooling, so tri-generation is also extremely energy efficient. Tri-generation's ability to run at near maximum capacity enables it to gain most from capital investment. This requires that excess electricity is sold into the local grid. Over time gas can become a carbon neautral option as the gas infrastructure is gradually transformed from using fossil fuel gas to renewable energy derived gas.

However, the power-to-gas and tri-generation options require considerable coordination between gas and electricity infrastructure to develop this highly energy efficient and low carbon solution. In the UK, a single company runs both the electricity transmission and gas grids removing vested interest barriers between the two grid infrastructures.

10.2 Distorted transmission and distribution investment deferment mechanisms

There are three factors that make the deferment of investment in transmission urgent:

- increased underutilisation of transmission and generation induced by climate change and increased penetration of non-scheduled SGUs, see Chapter 5;
- accelerated deterioration of transmission and distribution due to climate change makes, see Chapter 6; and
- increased severity of weather events, see the previous section.

All three are cost drivers for an increase in network provision per watt of electricity.

There are two ways to address the distorted transmission and distribution investment deferment mechanism:

- DSM; and
- the remuneration calculation of the NSPs.

10.2.1 Demand side management

DSM encourages people to reduce demand during peak load time or reduce demand generally. However DSM is inherently at odds with the profit motive to sell more electricity or provide more network infrastructure. DSM can take two forms to modify electricity usage patterns:

- price signals
- education

Introducing TOU billing and TOS payment for non-scheduled generation provides price signals to encourage the deployment of energy efficiency technology, small generation units, such as, solar PV and energy storage or batteries, see Bell and Foster (2012) and Section 9.1 for more details. This form of DSM requires smart meters or similar device. The NEM with a single monopoly transmission and distribution company within a single legislative area, as proposed in the previous section, would aid a NEM-wide roll out of smart meters. This would, provide monopoly buying powers and reduce coordination costs. A NEM wide rollout of smart meters is trivial compared to Italy's rollout of 33 million smart meters from 2001 to 2006 by its state monopoly utility, see Section 9.5 and 5.4. However, lessons from the poorly managed Victorian rollout need heeding, see section 5.4. TOU and TOS pricing can be regulated, so there lacks any requirement to simultaneously deregulate or privatise the retail electricity sector to gain the economic benefits and, more specifically, the transmission investment deferment benefits of the TOU and TOS.

The education of users is uncoordinated and lacks a national scheme. The exceptions are MEPS and star ratings on domestic appliances. The education aspect of DSM could also benefit from the recommendation in the previous section.

10.2.2 A smart grid road map for Australia

In addition to smart meters there are other smart grid features that can help with DSM and maximise the use of the existing infrastructure, see Section 9.5 for details and South Korea's deployment of a smart grid. Rolling out these features can also benefit from having a single NSP because of economies of scale and reduced coordination costs, as in South Korea. The Federal Government successfully ran the national telecommunications network previously as Telstra and now as the NBN. The privatised Telstra failed to deliver Australia a national fibre optic broadband network. However, the Federal Government, through the NBN, is transforming Australia's communication network from copper to fibre optic. This sets a precedent for a similar rollout of a smart grid in Australia after the failure by the State and private sectors to deliver.

10.2.3 Air conditioners requiring special treatment

In NSW, a key part of the reason for surging electricity prices is the need to build electricity assets to meet peak power demand, primarily due to the increased use of air conditioning, for four days of the year to meet high demand on hot days. $11 billion of network assets is being built to meet demand for just 100 hours a year and as much as 25% of electricity costs result from peak demand which occurs over a period of less than 40 hours a year (Dunstan & Langham 2010). A 2kW reverse-cycle air conditioner costs $1,500 a year to operate and yet imposes costs on the electricity network of $7,000 since it adds to peak demand (DRET 2012). These network costs are not paid by the consumer operating the air conditioner but by all NSW electricity consumers, whether or not they own air conditioners. See Section 4.7 for further details.

To address this problem, there are devices that can automatically switch off air conditioners during critical peak periods (Honeywell 2013; Peakrewards 2013). If people can tolerate short periods of discomfort, this provides for considerable saving on network investments. TOU billing is required to provide an incentive for those customers willing to allow the automated control of their air conditioner to save on critical peak prices. It is essential that such devices are installed along with smart meters to allow people to avoid peak pricing and help prevent the backlash against smarter meter that occurred in Victoria's deployment.

10.2.4 Addressing energy poverty

The failure to address energy poverty was one of the causes of the political backlash against smart meters in Victoria. Addressing energy poverty will aid acceptance of smart meters. People usually pay for their solar PV or solar hot water heating installations by increasing their house mortgage. This is appropriate in the case of long term investments such as solar PV. Renewable Energy Certificates makes the cost of installation more affordable. This approach works for house owners but not for renters. The fact that proportionately more low income individuals rent houses goes some way to explain why the highest (richest) quintile have twice the rate of solar PV installations, compared with the lowest (poorest) quintile (Bell & Foster 2012). The situation is similar for solar hot water. The low solar PV penetration in the lowest quintile is due to the dual problem of low income and rental accommodation. Trying to address this poverty trap with subsidised loans is insufficient. A solution is required that acknowledges the tenant-landlord relationship and the consequent misalignment of benefits and costs. Targeting energy poverty in this group through solar PV installations not only addresses equity but makes effective use of solar PV, as individuals on low incomes are likely to spend more time at home during the day. The implementation of renewable energy within the public rental housing sector is entirely feasible and social equity concerns provide a rationale. In contrast, the profit motive of the private rental sector provides a deterrent that is more difficult to overcome.

Thus, the state and territory housing authorities should be required to directly support installation of solar PV and solar hot water. This action has become imperative given the requirement to move to TOU billing and recent moves to deregulate the domestic tariff in Australia, to protect the most financially vulnerable in society. The installation of solar PV, along with smart meters, would aid acceptance of the time of use tariffs. However, the State or Territory housing authorities hold a small and diminishing proportion of rental accommodation stock. This is associated with an overall increase in the proportion of people living in rental accommodation.

So, addressing ways to encourage solar PV installations in private rental accommodation is a priority in State or Territory housing authorities. Because the renter enjoys all the benefits of reduced electricity bills, there is no incentive for the landlord to install solar PV. A higher rent could be charged but, again, long term investment myopia tends to dominate.

Investment myopia can be addressed by offering subsidised loans to landlords. But we know that loans in isolation have already proved unsuccessful in the UK's green policy program. So there is a case for appealing to the landlord's desire for capital gains by making houses without solar PV ineligible for tax free capital gains. Consideration needs also to be given to the fact that some houses are unsuitable for solar PV. The carrot and stick approach to investment myopia and capital gains expectation, respectively, could encourage an increased uptake of solar PV in the private rental accommodation (Bell & Foster 2012).

10.2.5 Changing remuneration calculations for network service providers

However, the remuneration calculation for NSP is at odds with the installation of such devices and DSM generally. The profits of the NSPs are calculated on their capital expenditure, which encourages them to build more infrastructure. If peak demand increases, the NSPs are legally obliged to build more infrastructures to accommodate the demand and the NSP profits from accommodating the demand. This is a perverse dynamic from both climate change and economic perspectives. This remuneration calculation needs to be changed to align the profit motive of the NSP with DSM. This can be achieved by making the utilisation of the existing infrastructure a business objective of the NSP. Publically owned companies are better at handling multiple objectives, such as DSM, than privately owned companies with their simple profit maximising objective. In Section 9.6 we discussed these issues in more detail.

10.3 Lacking mechanisms to develop a diversified energy portfolio

A portfolio of energy sources is required to reduce supply risk and improve the resilience of the NEM. The NEM's current coal generation would gradually switch to gas generation under a functional CPRS, doing little to broaden the portfolio of energy sources. The RET ensures a mix between fossil fuels and renewable energy but the current RET has exacerbated the first mover advantage of onshore wind and solar PV to the detriment of a wider portfolio of energy sources and technologies. This section addresses the following issues:

- diversity and first mover advantage of small scale solar PV and onshore wind;
- power purchase agreements and risk;
- poor competition in the retail sector;
- grid connection holdups;
- feed-in tariff reverse auctions; and
- optimally diversified portfolios.

10.3.1 Modified RET and reverse auctions for cost effective diversification

Two factors are discussed to address the diversity and first mover advantage:

- modified RET; and
- reverse auctions.

A modified RET that allocates targets to specific technologies and energy sources would help develop a wider portfolio of energy sources with different energy profiles to solar PV and onshore wind. An adjunct or alternative approach is the feed-in tariff reverse auction planned by the ACT Minister for the Environment and Sustainable Development (Corbell 2011a) for two large scale solar PV plants, as discussed in Section 9.1. Wood and Muller (2012) provide a comprehensive discussion of the use of a feed-in tariff reverse auction for large scale renewable capacity. In Section 6.12 we discussed the need for a portfolio approach. In Section 9.9 we discussed alternative schemes used in Germany and the UK and their flaws. Germany has managed to achieve some of the highest penetrations of renewable energy in world but has simultaneously developed some of the highest domestic electricity prices. Feed-in tariff reverse auctions provide a remedy to this situation.

10.3.2 Power Purchase Agreements: a barrier to a diversified energy portfolio

However, both a modified RET and feed-in tariff reverse auctions incompletely address diversification. A further major obstacle is obtaining a PPA, a contract from a retailer with the promise to buy the generator's electricity. A PPA is required by banks before they will fund a project. The Moree Solar and Solar Dawn Projects' failure to achieve a PPA shows that the current institutional structure is inadequate. There is a requirement to improve PPA processes to ensure projects can start. In Section 9.4 we discuss further RET and PPA.

For retailers in a competitive market to give a long term contract to buy electricity is difficult for two reasons:

- long term demand is difficult predict
- customers can switch their retailer

This situation requires risk management skills where the sellers of electricity take on a contract to ensure a fixed future price and the buyers of the electricity take on the risk that the prices may differ from the contracted price. But the buyer of the electricity charges a premium for taking on the risk to offer the seller of electricity a contract price below the expected price. This situation bears similarities to insurance and banking where policy and mortgages are issued and there is a probability that the some of the insurance policies will have claims and some of the mortgagers will default. The larger the bank or insurance company the easier it is to spread the risk. The classic large scale risk management example in Australia is Medicare with the entire population.

In addition, there are only three large retailers, so the competition to offer PPAs is fairly low. Compounding this lack of competition there is an inherent conflict of interest as the three largest retailers are also generators. So, from both the generators' and consumers' perspectives, the competition in the combined retail generator sector is less than desirable.

There are at least two options to address the inadequate PPA process and to improve risk management. One, the government enters into the PPA directly with the generator. Two, the retail sector is nationalised. The first option has the following disadvantages:

- the big three retailer-generators will eventually dominate both generation and retail markets reducing competition and extracting higher profits from electricity consumers; and
- profit motive is at odds with the requirements introduce DSM and technologies such as tri-generation.

The second option provides the following advantages:

- promoting healthier completion amongst the generators;
- removing conflict of interest between generators and retailers in offering PPAs;
- reducing customer churning risk in offering PPA to zero;
- reducing conflict of interest over introducing DSM technologies; and
- reducing smart grid rollout coordination costs.

A similar company structure to the monopoly retailer in South Korea could be adopted, that is the Federal Government could hold a minimum 51% stake and the remainder held by the states or privately.

10.3.3 Connecting to the grid a further barrier to a diversified portfolio

The process for renewable energy generators to connect to the grid provides a further barrier to a diversified portfolio. The introduction of new distributed generation may reduce utilisation of the network infrastructure, so connecting distributed energy sources is not in the profit interest of the NSPs. To maintain this barrier, the NSPs simply do nothing to improve the connection processes. These connection processes were developed in the days when only large coal generators connected to the grid and connecting small generators seen as inherently risky and troublesome. The connection process is long and onerous, which was adequate for large projects with large budgets and time scales but unsuitable for the smaller distributed generation projects with much smaller budgets and shorter planning times. There is no incentive to improve the connection procedures as the distributed generation may cause further underutilisation of network infrastructure. So there is an inherent conflict of interest between the profit motive of the NSPs and reducing GHG emissions. This defence of profits by bureaucratic inertia is a maladaptation to climate change.

Remedies to this barrier include providing a nationally consistent connection process to provide learning economies for applicants. The recommendation in Section 10.1 would aid in this provision. The provision of downloadable examples of connection applications would also help. So would the introduction of a business objective for the NSP to improve resilience of the electricity infrastructure using distributed generation. Government owned organisations are better equipped to meet multiple objectives.

10.3.4 Feed-in tariff reverse auction candidates

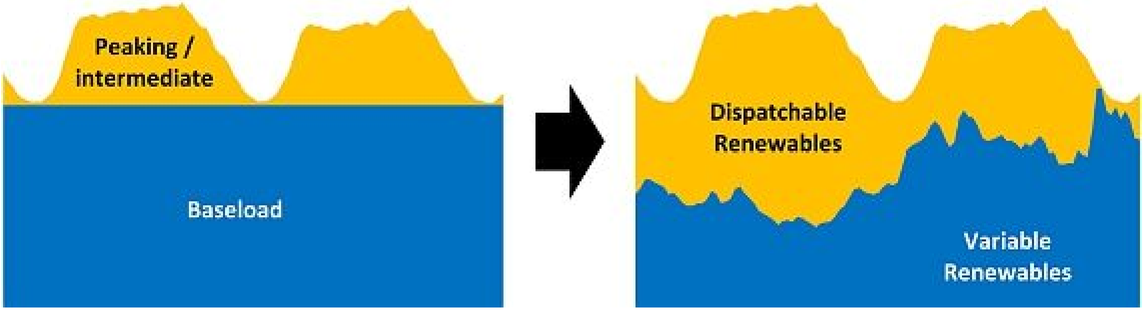
This section provides a list of candidate technologies suitable for the feed-in tariff reverse auction. An advantage of the reverse auction is its ability to obtain the lowest price for the implementation whether the technology is new or commercially proven.

- Section 6.10.1 discussed offshore wind and wave generation as suitable candidates for portfolio diversification as Australian is well endowed with these natural resource but lacks a commercial venture.
- Section 6.10.2 discussed power-to-gas as another technology worthy of support for a commercial venture in Australia.
- Another solar boost project similar to the Kogan Creek project discussed in Section 6.2.
- Another coal power station conversion similar to Collinsville coal power station conversion into a hybrid gas solar generator.

10.3.5 Optimal portfolio of renewable energy to reduce overall costs

This section discusses optimisation of a portfolio of renewable energy sources as a further method to reduce the overall cost of a renewable portfolio. Figure 10-2 illustrates a shift from baseload coal and gas acting in an intermediate or peaking role to a renewable scenario consisting of dispatchable and variable renewables.

Figure 10-2 Shifting from baseload coal and intermediate or peaking gas to dispatchable and variable renewables



(Source: Riesz 2013)

Under the baseload regime, coal meets the bulk of the demand and intermediate or peaking gas meets any demand above the baseload supply. In a similar way, variable renewables can meet the bulk of the demand and dispatchable renewables meet the demand that the variable renewables are unable to meet. Just as gas generation is more expensive than coal; dispatchable renewable energy, such as, concentrated solar thermal with storage tends to be more expensive per Watt than variable renewables, such as, onshore wind. So, there is potential to optimise the mix of these two forms of renewable energy to reduce overall costs. Elliston et al. (2013) simulate for the NEM for the existing level of reliability the optimal mixture of renewable electricity using onshore wind, solar PV, concentrated solar thermal (CST) with storage, hydroelectricity, pumped hydro and bio-fuelled gas turbine. They find that at moderate carbon prices that 100% renewable electricity would be cheaper on an annual basis than replacement by fossil fuel generation. The technology shares in four scenarios are onshore wind 34-41%, solar PV 24-34%, CST with storage 7-13%, hydro 4-5%, pumped hydro 2% and bio-fuelled gas turbine 19-23%. There was spilled energy of between 7 to 27 TWh depending on the scenario. Expanding Elliston et al.'s (2013) portfolio to include power-to-gas technology provides a useful outlet for the spilled energy and alternative source of gas for the bio-fuelled gas turbine.

Furthermore, using additional variable renewables with uncorrelated profiles, such as wave and solar PV, would reduce the need for the more expensive dispatchable renewables and increase the diversity of sources of renewable energy to provide further resilience to the NEM.

However, there is a requirement for coordination to achieve an optimal portfolio of these technologies both from the retail sector to provide PPA and from NSPs to provide transmission to suitable new locations. Solutions to PPA impediments in the retail sector have already been discussed. There are two issues impeding the introduction of new transmission to suitable areas:

- Regulatory Investment Tests for Transmission (RIT-T); and
- The fragmentation of the transmission companies and conflict of interest.

RIT-T requires that new investment is built to meet peak demand. This essentially put the consideration of new transmission to sites suitable for renewable energy outside of the current RIT-T procedures. The RIT-T procedure requires changing to incorporate economic viability tests for sites suitable for renewable energy. This change would align RIT-T with the broader government policies of addressing climate change. Chapter 7 details transmission requirements to incorporate new sites suitable for renewable energy. Section 7.7 further discusses RIT-T.

There is a conflict of interest in deploying the optimal size of transmission to new locations suitable for clusters of wind farms over who pays and who benefits. Section 6.7 further discusses this conflict of interest. Additionally, there is the intergenerational aspect. Since future generations will benefit from these long term investments in transmission to new renewable sites, there is justification for long term loans to finance these projects. Bear in mind that the State Governments funded the transmission for the existing coal fleet. The recommendation in Section 10.1 goes some way to addressing both the financing and conflict of interest issues.

10.4 Failing to model and to treat the NEM as a national node based entity rather than state based

The final maladaptation to climate change is the requirement to change focus from the NEM as a collection of island states to a truly national electricity market composed of nodes. An international comparison of the political and economic coordination overheads of electricity systems in Section 9.6 shows that the NEM carries an excessive burden. This coordination burden is an extra cost for both taxpayers and electricity consumers and detracts from a national node based focus. Section 6.1 discusses the current focus on intrastate rather than interstate transmission as a bottleneck in the NEM. Using a national node based model, Chapter 7 models the effect of climate changes on the transmission line congestion and discusses remedies to these congestion bottlenecks.

10.4.1 Misinformed policy

Failure to model the NEM by node could lead to misguided policy causing maladaptation to climate change. In Chapter 2 and 4 we discussed why there is a requirement to model the NEM by node rather by state for five reasons:

- uneven projected population growth within each state, except Queensland;
- sensitivity analysis of demand to temperature shows a discrepancy between home state and capital city;
- there is a significant difference in base temperature between home state and capital city, which indicates difference in acclimatisation and heat island effects;
- uneven weather patterns within each state; and
- uneven climate change projections within each state.

10.4.2 Provision of node based data

In Chapters 3, 5 and 7 we modelled the NEM as a national node based entity and this has helped to inform this discussion. The recent poor forecasting of electricity demand on the NEM raised issues of the models missing some important aspect. In Section 5.1 we developed the concept of gross demand and net demand. Modelling gross and net demand shows that some demand is being met in part by non-scheduled generation, such as, residential solar PV. This went some way to explain the poor forecast. Some of the difficulties in modelling gross demand could be overcome by AEMO:

- supplying half hour demand data by node;
- providing GIS maps of each nodes region; and
- providing accurate records of the non-scheduled generation by node to enable gross and net demand modelling, see Section 5.1.

Addressing these issues would enable modellers to improve their energy demand forecasts, so to better inform policy. As non-scheduled generation increases, the requirement to model non-scheduled demand becomes more pressing.

10.4.3 Locational Marginal Pricing

Finally, a node based price signals would promote more appropriate investment decisions, as required in Section 10.2. The recommendation in Section 10.1 would help transform the State focus of the NEM to a more national node-based perspective. Chapter 7 discusses the effect of climate change on the locational marginal prices for each node using a national node based model described in Appendix B and C.

10.4.4 Company boundaries between NSPs are weakness in the network

The boundaries between companies on a network are weakness in the network. The recommendation in Section 12.1 eliminates this source of failure.

10.5 Summary

The NEM is at the confluence of a technological transformation, rising electricity prices and requiring adaptation to climate change. The current political and economic structure, with its massive coordination overhead, is ill equipped to meet the challenge. The profit motive of the private sector is at odds with DSM strategies that could both moderate electricity price rises and help adapt to climate change. The current business model for the three private retailer-generator companies is outmoded when confronted with technology such as tri-generation. The customer who installs a tri-generation unit wants to sell their excess electricity to the grid, which is in direct competition with retailer-generator.

It would be remiss to withhold discussion of the recommendations within the wider socioeconomic context of Australian as the electricity and gas sectors are major employers and affect nearly every aspect of the Australian economy. The aforementioned recommendations are much more than just a microeconomic optimisation exercise. The recommendations are evidence based and, in some cases, run counter to the trend to deregulate and privatise utilities since the 1980s. The US has been at the vanguard of this deregulation trend but has developed serious income inequity to such an extent that there has been a decline in median male income in the US since the 1970s and associated increases in homelessness. The privatisation and deregulation of the remaining parts of the electricity industry will take Australia closer to the socioeconomic structure of the US. Consistent with the US experience, the management of the combined generation-retail companies and NSPs will gain substantially from the deregulation and privatisation of the remaining utilities at the expense of employees (Alvaredo et al. 2013). Following the US's lead would also hinder Australia's adaptation to climate change and attempts to contain electricity prices.

Lastly, the Federal Government has already proven its ability to coordinate a national technological transformation in the NBN while meeting multiple objectives. This transformation provides a successful template for the National Smart Grid.

11. CONCLUSION

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The literature reviews in Chapters 2, 4, 6, 8 and 9 find four factors contributing to the NEM's maladaptation to climate change:

1. institutional fragmentation, both economically and politically;
2. distorted transmission and distribution investment deferment mechanisms;
3. lacking mechanisms to develop a diversified portfolio of generation technologies and energy sources to reduce supply risk; and
4. failure to model and to treat the NEM as a national node based entity rather than state based.

This book addresses these four maladaptations to climate change with original research in Chapters 3, 5, 7, 8 and 9. The findings of the literature review and original research chapters inform the recommendations discussed in Chapter 10 to address the four maladaptations to climate change. The Non-technical summary for policy makers in the preface provides these recommendations without discussion or detail. Detailed justification for these recommendations can be found in the main body of the book.

The original research chapter are:

1. identifying suitable emission and climate change scenarios;
2. the impact of climate change on electricity demand;
3. the impact of climate change on electricity generation capacity and transmission networks;
4. analysing the effects of changes in water availability on electricity demand-supply; and
5. assessing the current institutional arrangements for the development of electricity infrastructure to inform more flexible arrangements for effective adaptation.

12. APPENDIX

A SELECTING GLOBAL CLIMATE MODELS FOR THIS PROJECT

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This appendix describes the process that Clarke and Webb (2011) use to select GCMs for this project. Clarke, Whetton and Hennessy (2011) describe the process in more detail.

1. In the first instance some GCMs are rejected as Irving et al. (2011) find some GCMs perform poorly in the Pacific Island region where the models are assessed against nine criteria. One of criteria is the ability to model the El Niño Southern Oscillation, which is relevant to Eastern Australia and most of the NEM region. So, Irving et al. (2011) recommend rejecting the following models for the purpose of creating climate change projections for impact studies in this region: INM-CM3.0, PCM and GISS-EH, INGV-SXG, GISS-AOM and GISS-ER.
2. Models are then grouped into relevant climate futures as Clarke, Whetton and Hennessy (2011) describe for each grid cell in Figure A-1 .
3. Table A-1 shows the results of selecting the GCMs for this project.
4. In this step the *Most Likely, Worst Case* and *Best Case* climate futures are considered. The *Most Likely* climate future is defined as that future represented by the greatest number of models. The *Worst Case* is defined as the climate future with the greatest increase in temperature. The *Best Case* is defined as the climate future with the least increase in temperature. The matrices for each grid box are calculated using combinations of mean annual temperature and mean annual rainfall projections for 2030 forced with the A1FI SRES emissions scenario.
5. The fewest number of models that represent the *Most Likely, Worst Case* and *Best Case* climate futures for each region are selected. For the *Most Likely* case, FGOALS-g1.0 best represents Queensland and MRI-CGCM2.3.2 best represents the remainder of the NEM region. For the worst case, CSIRO-Mk3.5 best represents the whole NEM region. For the best case, MIROC3.2 best represents the whole of the NEM region, excepting Tasmania.
6. Since this project is forming a projection for the whole of the NEM region, selection of one model for each of three cases is advised. In this way model consistency and integrity of results can be upheld across the NEM region. There is only one *Worst Case* model that is the CSIRO-Mk3.5 model, so there is no issue.
7. However there are two *Most Likely* case models that are FGOALS-g1.0 and MRI-CGCM2.3.2. So, a compromise is made in order to select between these two models. In Table A-1 the MRI-CGCM2.3.2 model in Grid Box 39 is the model that is 2nd most representative of the *Most Likely* case but the MRI-CGCM2.3.2 model has a much drier projection that the 'strictly' *Most Likely* case model called FGOALS-g1.0.

8. The alternative is to use both MRI-CGCM2.3.2 and FGOALS-g1.0 to represent the *Most Likely* climate future.
9. Since MIROC3.2 represents the *Best Case* for the whole of the NEM region other than Tasmania and MIROC3.2 represents the 2nd *Best Case* for Tasmania, the decision is made to use MIROC3.2 to represent the *Best Case* for the whole of the NEM region.

Table A-1 Selecting global climate models for this project

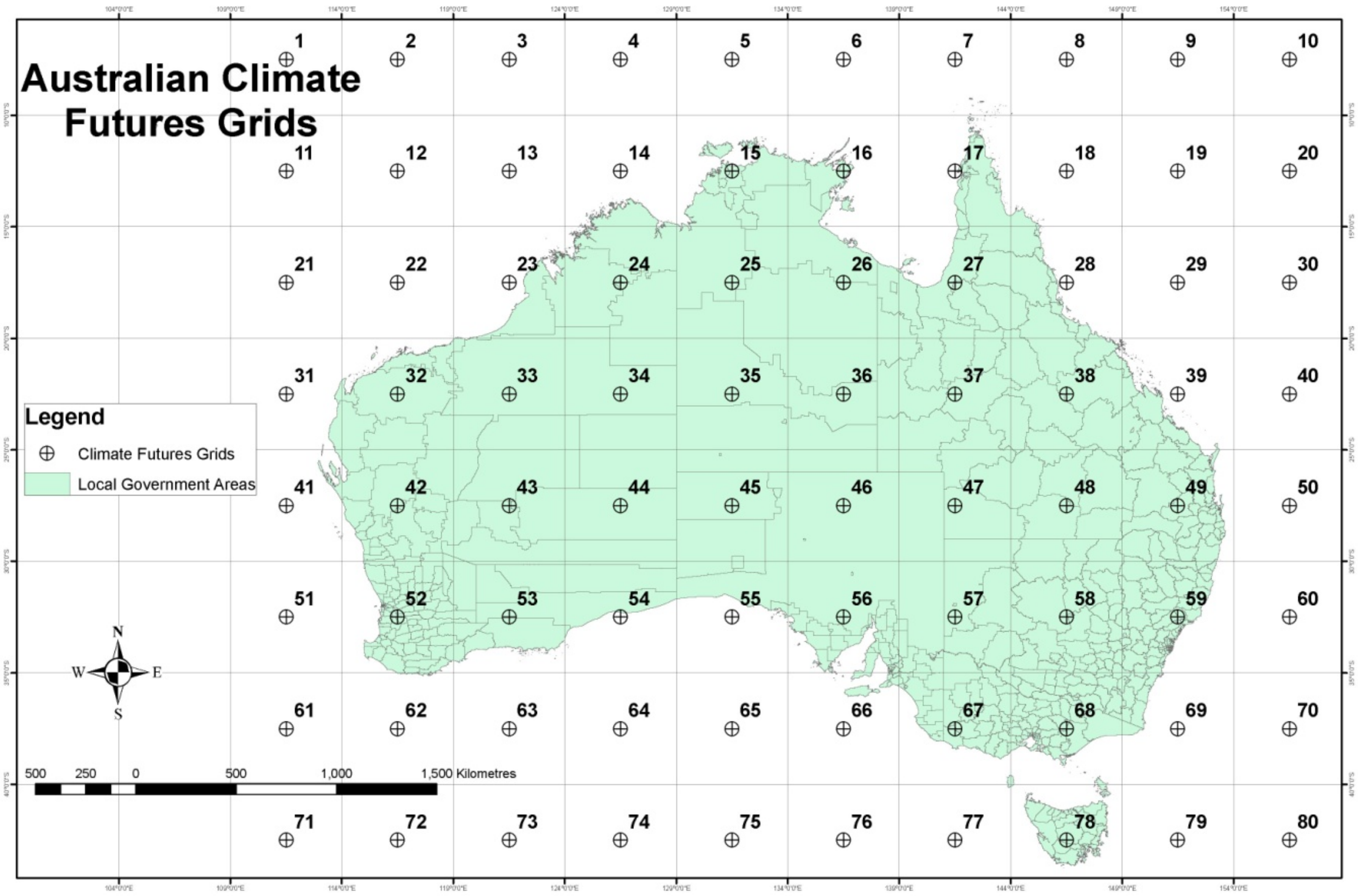
Grid Box in Figure A-1	Most Likely	Worst Case (Hottest)	Best Case (Coolest)	State	Region	* Surrogate	2nd pass Most likely
28	FGOALS-g1.0	CSIRO-Mk3.5	MIROC3.2(medres)	Qld	FNQ	MRI-CGCM2.3.2	MRI-CGCM2.3.2
38	FGOALS-g1.0	CSIRO-Mk3.5	MIROC3.2(medres)	Qld	NQ	MRI-CGCM2.3.2	MRI-CGCM2.3.2
39	FGOALS-g1.0	CSIRO-Mk3.5	MIROC3.2(medres)	Qld	CQ	MRI-CGCM2.3.2	MRI-CGCM2.3.2
46	MRI-CGCM2.3.2	CSIRO-Mk3.5	MIROC3.2(medres)	SA	North		MRI-CGCM2.3.2
49	FGOALS-g1.0	CSIRO-Mk3.5	MIROC3.2(medres)	Qld	SEQ	MRI-CGCM2.3.2	MRI-CGCM2.3.2
56	MRI-CGCM2.3.2	CSIRO-Mk3.5	MIROC3.2(medres)	SA	South		MRI-CGCM2.3.2
57	MRI-CGCM2.3.2	CSIRO-Mk3.5	MIROC3.2(medres)	NSW			MRI-CGCM2.3.2
58	MRI-CGCM2.3.2	CSIRO-Mk3.5	MIROC3.2(medres)	NSW			MRI-CGCM2.3.2
59	MRI-CGCM2.3.2	CSIRO-Mk3.5	MIROC3.2(medres)	NSW			MRI-CGCM2.3.2
67	MRI-CGCM2.3.2	CSIRO-Mk3.5	MIROC3.2(medres)	Vic	West		MRI-CGCM2.3.2
68	MRI-CGCM2.3.2	CSIRO-Mk3.5	MIROC3.2(medres)	Vic	East		MRI-CGCM2.3.2
78	MRI-CGCM2.3.2	CSIRO-Mk3.5	CNRM-CM3	Tas			MRI-CGCM2.3.2

* Surrogate notes:

- In the grids for Queensland, surrogates have been selected in order to have a single model to represent the *Most Likely* case across the entire NEM region.
- However, in grid box 39 the surrogate model called MRI-CGCM2.3.2 is from the 2nd *Most Likely* climate future but is approximately 10% drier than the strictly most representative model called FGOALS-g1.0.
- For the grid box 78 for Tasmania, the surrogate model MIROC3.2 (metres) is the 2nd Best climate future for Tasmania.

(Source: Clarke & Webb 2011)

Figure A-1 Australian Climate Futures Grids



(Source: Clarke & Webb 2011)

B NODE DIAGRAMS OF THE AUSTRALIAN NATIONAL ELECTRICITY MARKET

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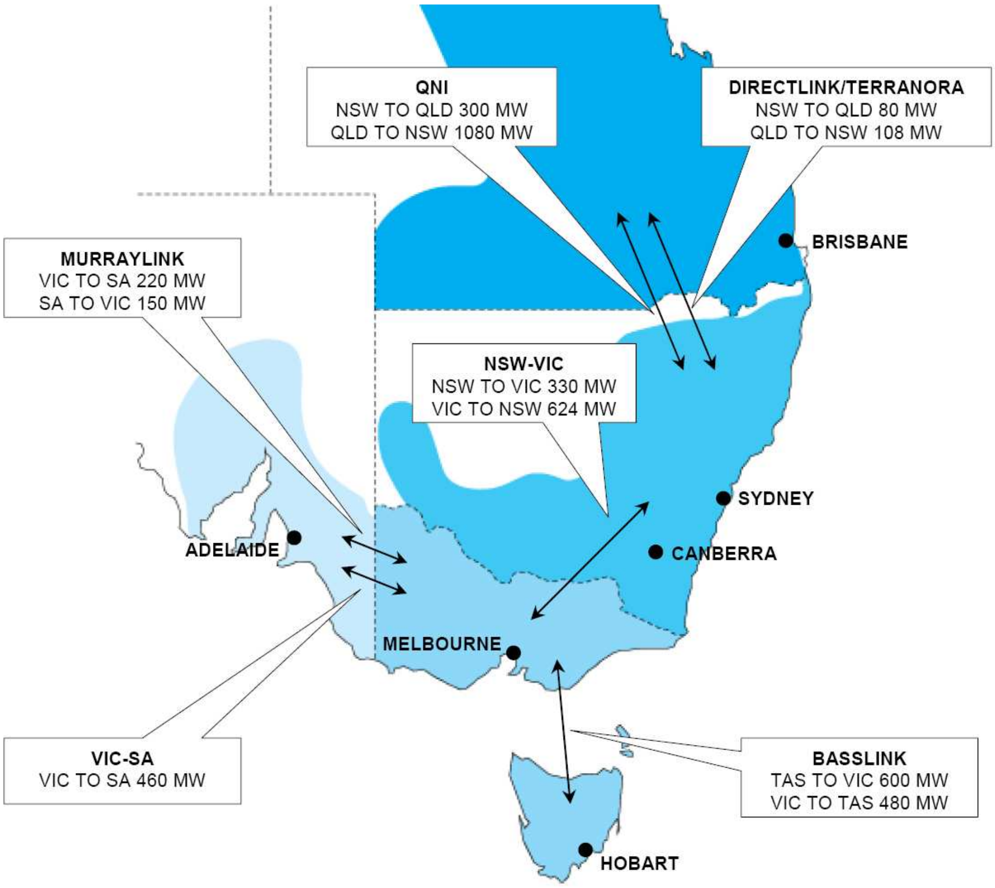
This appendix provides network diagrams of the nodes discussed in this report. These nodes are also known as load serving entities (LSE) or demand regions. However, three of the nodes are supply only nodes without associated demand. Figure B-1 shows the interconnectors between the States, which provides an overview of the more detailed state network diagrams in the following figures.

Figure B-1 Interconnectors on the NEM



(Source: Tamblyn 2008, p. 7)

Regarding the numbering on the nodes, if the node number and demand region number are the same, just one number is placed on the node. If the node number and demand region number differ, both numbers are placed on the node in the following way: (node number, demand region number). For instance, (10, 11) is on the node at North Morton.

If the node is a generation only node the following notation is used (node number, -). For instance, (16, -) is on the node at Bayswater.

Figure B-2 Stylised topology of QLD transmission lines and LSE

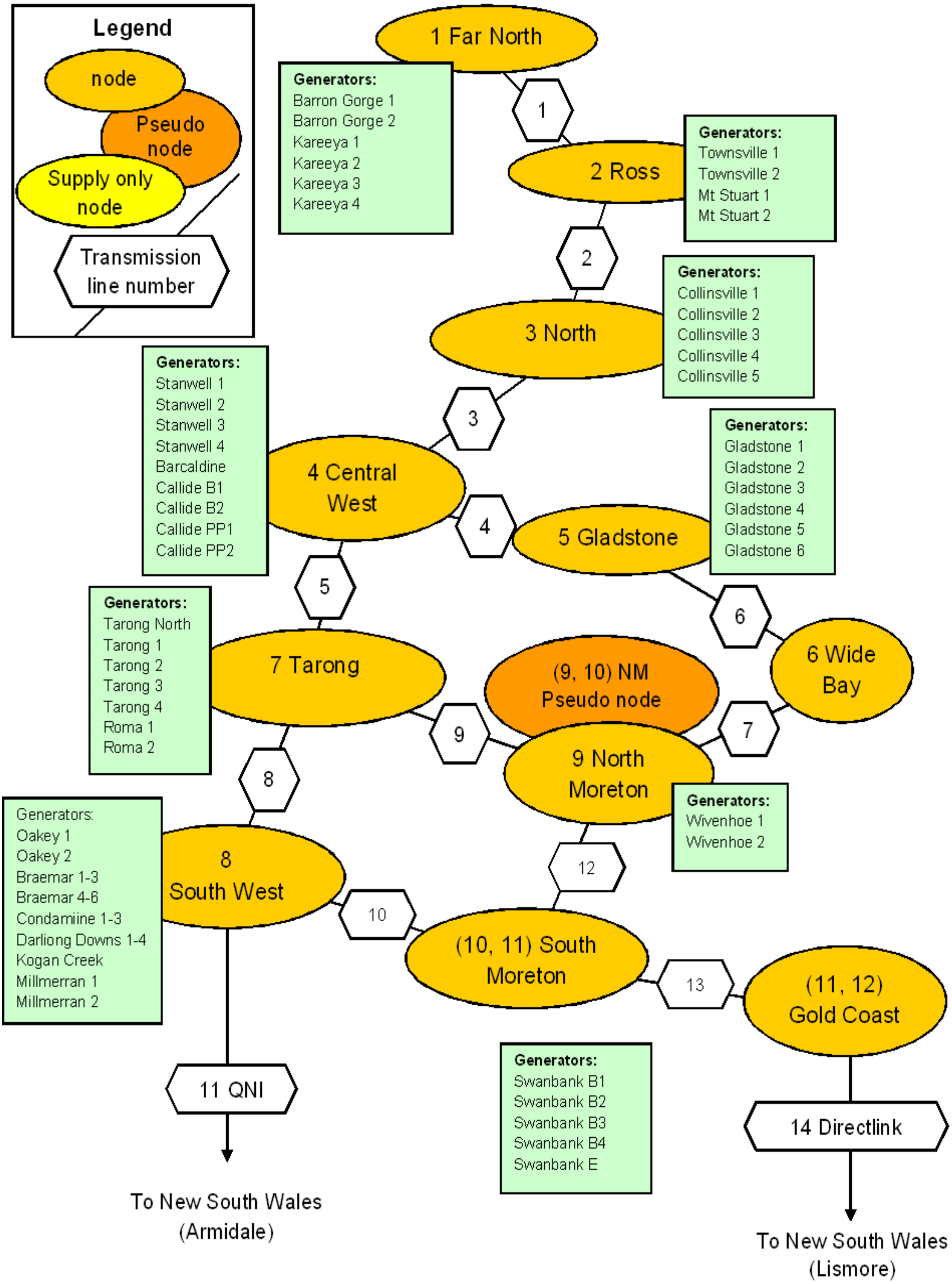


Figure B-3 Stylised topology of NSW transmission lines and LSE

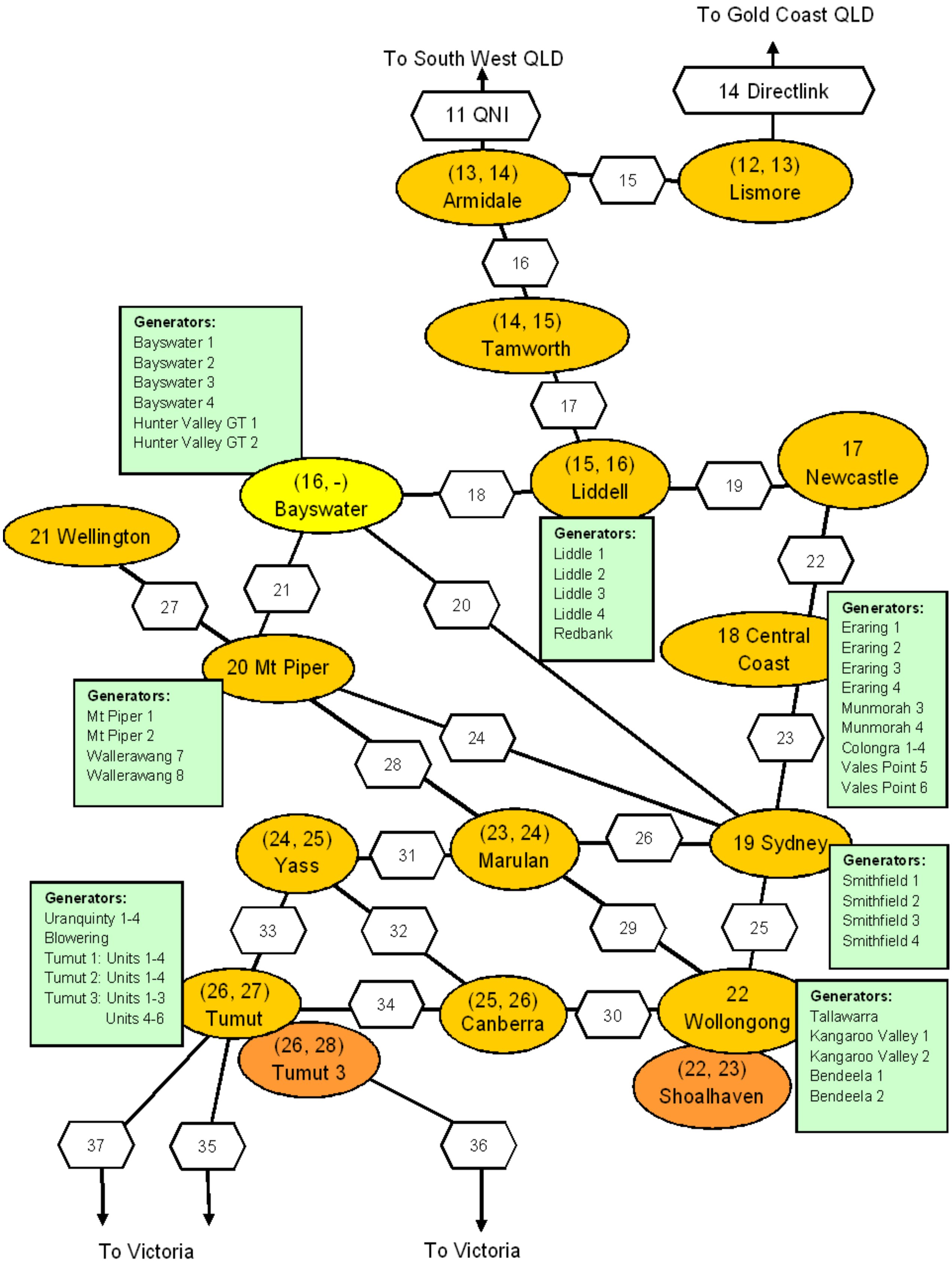


Figure B-4 Stylised topology of VIC transmission lines and LSE

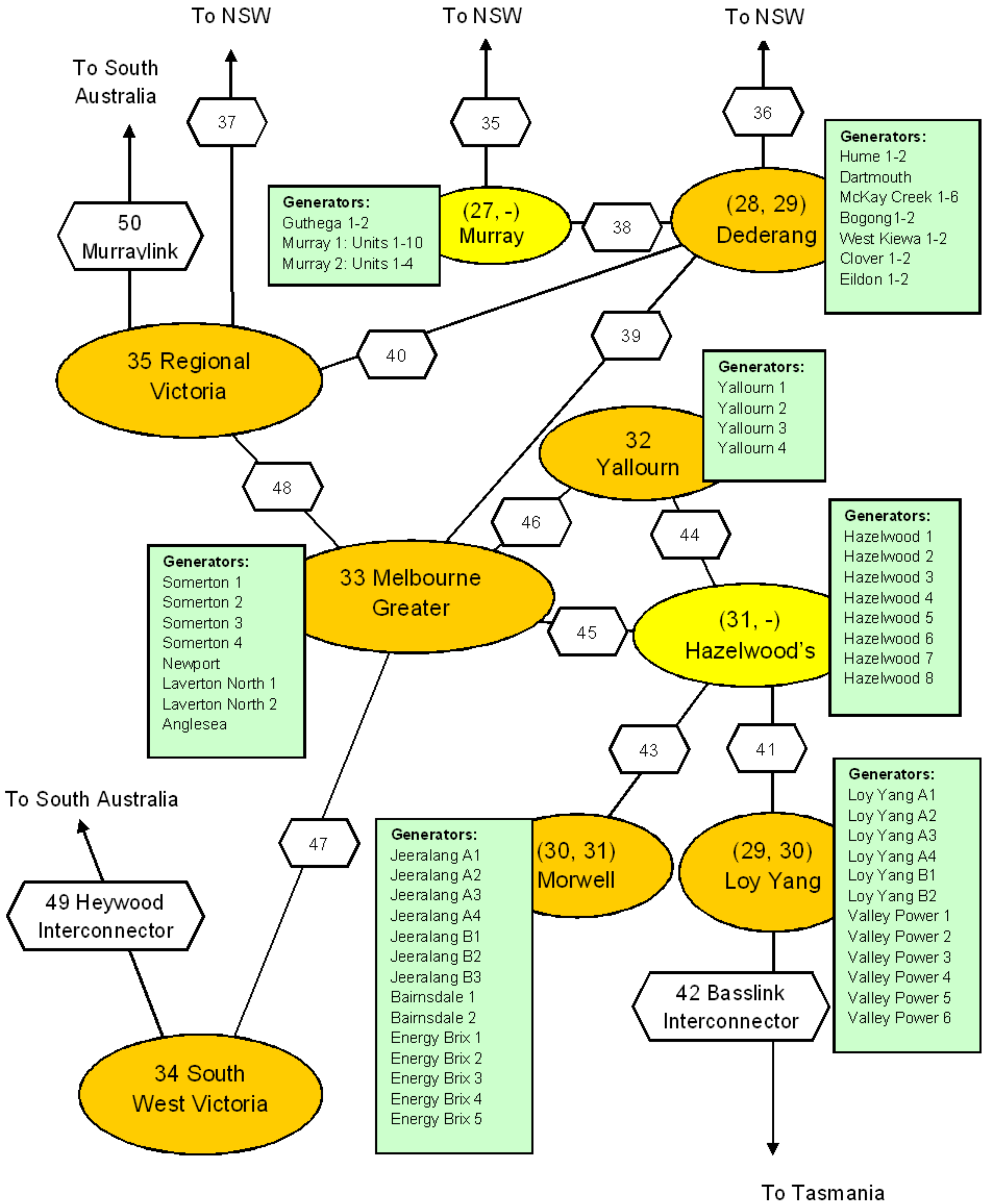


Figure B-5 Stylised topology of SA transmission lines and LSE

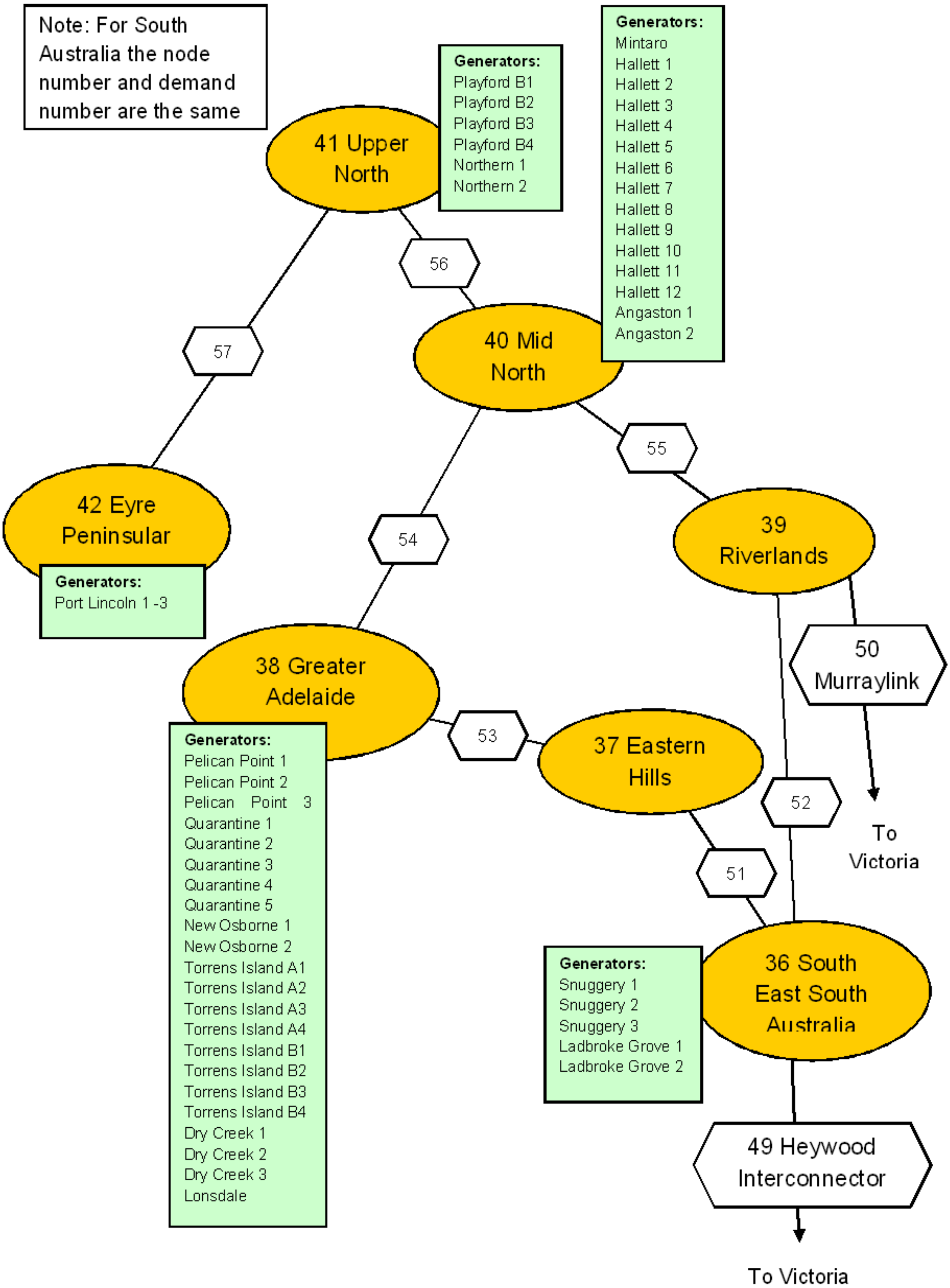
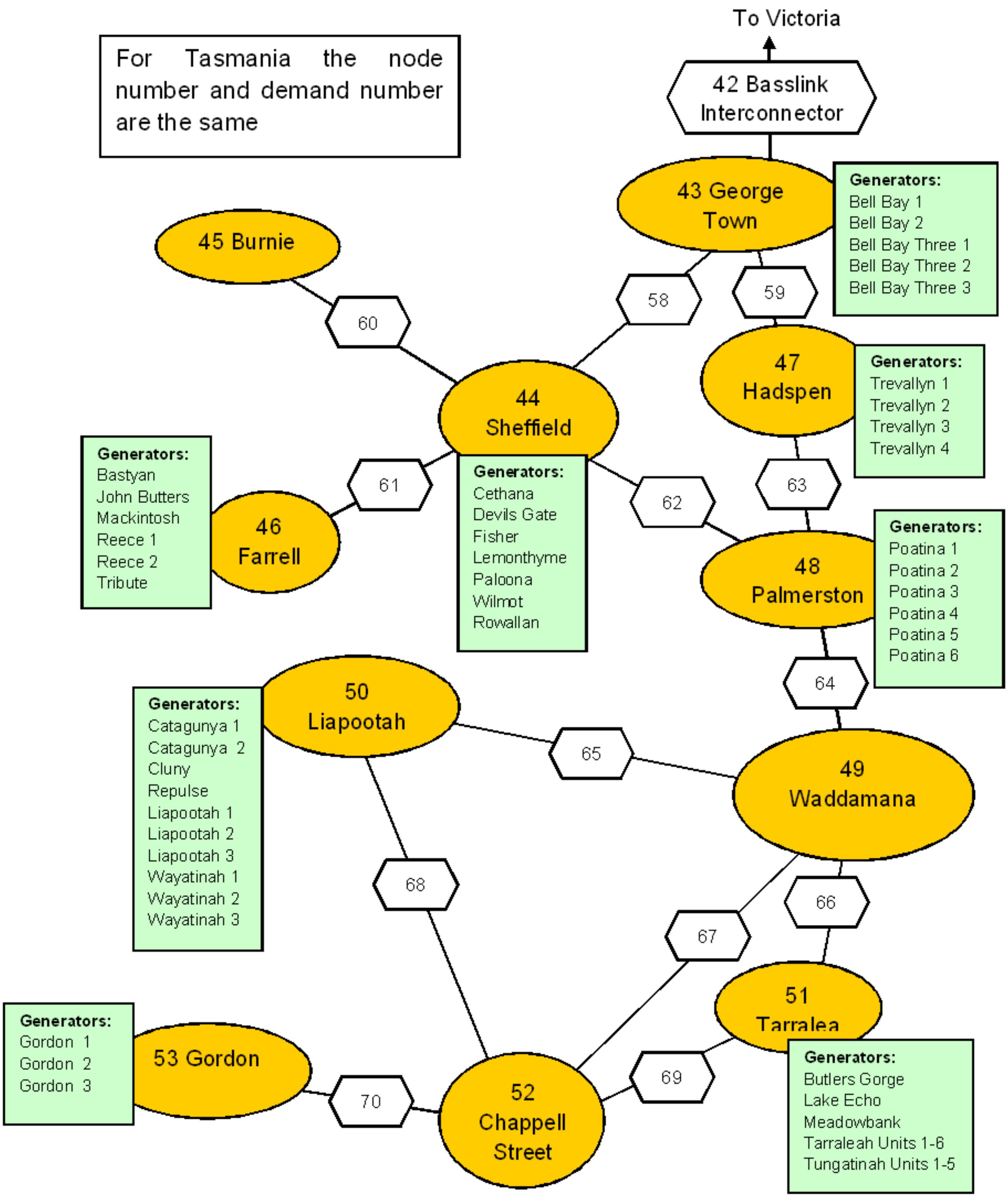


Figure B-6 Stylised topology of TAS transmission lines and LSE



C AUSTRALIAN NATIONAL ELECTRICITY MARKET MODEL

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This appendix discusses the ANEM Model. Chapter 7 uses the ANEM model to assess the impact of climate change on four economics factors:

- spot price;
- energy generated by type of generator;
- carbon emissions; and
- transmission line congestion.

The ANEM model uses the node and transmission line topology in Appendix B. ANEM is an agent based model and the agents include demand and supply side participants as well as a network operator. The behaviour of these agents is constrained by the transmission grid whose network configuration is defined by the nodes and transmission lines shown in Appendix B. The following sections provide an outline of the ANEM model and present the principal features of the agents in the model. The ANEM's algorithm used to calculate generation production levels, wholesale prices and transmission lines power flows is discussed. Finally, practical implementation considerations are discussed.

C.1 Outline of ANEM model

The methodology underpinning the ANEM model involves the operation of wholesale power markets by an Independent System Operator (ISO) using LMP to price energy by the location of its injection into, or withdrawal from, the transmission grid. ANEM is a modified and extended version of the American *Agent-Based Modelling of Electricity Systems* (AMES) model developed by Sun and Tesfatsion (2007a, 2007b) and utilises the emerging powerful computational tools associated with Agent-based Computational Economics (ACE). This type of modelling is built upon a very realistic representation of the network structure under consideration with high frequency behavioural interactions that are made possible by the availability of powerful computing resources. The important differences between the institutional structures of the Australian and USA wholesale electricity markets are also fully reflected in the modelling undertaken and outlined more fully in Wild, Bell and Foster (2012), Section 1).

To understand the impact that climate change might exert on key infrastructure and participants in the wholesale electricity market requires a realistic model containing many of the salient features of the NEM. These features include realistic transmission network pathways, competitive dispatch of all generation technologies with price determination based upon variable cost and branch congestion characteristics and intra-regional and inter-state trade.

In the ANEM model, a Direct Current Optimal Power Flow (DC OPF) algorithm is used to determine optimal dispatch of generation plant, power flows on transmission branches and wholesale prices. This framework accommodates many of the features mentioned above including: intra-state and inter-state power flows; regional location of generators and load centres; demand bid information and the following unit commitment features:

- variable generation costs;
- thermal MW limits (applied to both generators and transmission lines);
- generator ramping constraints;
- generator start-up costs; and
- generator minimum stable operating levels.

C.2 Principal features of the ANEM model

The ANEM model is programmed in Java using RePast (http://repast.sourceforge.net/repast_3/download.html), a Java-based toolkit designed specifically for agent base modelling in the social sciences. The core elements of the model are:

- The wholesale power market includes an ISO and energy traders that include demand side agents called LSEs and generators distributed across the nodes of the transmission grid.
- The transmission grid is an AC grid modelled as a balanced three-phase network.
- The ANEM wholesale power market operates using increments of one hour.
- The ANEM model ISO undertakes daily operation of the transmission grid within a single settlement system, which consists of a real time market settled using LMP.
- For each hour of the day, the ANEM model's ISO determines power commitments and LMPs for the spot market based on generators' supply offers and LSEs demand bids which are used to settle financially binding contracts.
- Transmission grid congestion in the spot market is managed via the inclusion of congestion components in the LMP.

C.2.1 Transmission grid characteristics in the ANEM model

The transmission grid utilised in the ANEM model is an AC grid modelled as a balanced three-phase network. In common with the design features outlined in Sun and Tesfatsion (2007a), we make the following additional assumptions:

- The reactance on each branch is assumed to be a total branch reactance, meaning that branch length has been taken into account in determining reactance values;
- All transformer phase angle shifts are assumed to be 0;
- All transformer tap ratios are assumed to be 1; and
- All line-charging capacitances are assumed to be 0.

To implement the DC OPF framework used in the ANEM model, two additional electrical concepts are required. These are base apparent power which is measured in three-phase Megavoltamperes (MVAs), and base voltage which is measured in line-to-line Kilovolts (kVs). These quantities are used to derive the conventional per unit (PU) normalisations used in the DC OPF solution and facilitate conversion between Standard International (SI) and PU unit conventions.

The transmission grid can be viewed as a commercial network consisting of pricing locations for the purchase and sale of electricity power. A pricing location is also a location at which market transactions are settled using publicly available LMP's and coincides with the set of transmission grid nodes.

The transmission grid in the ANEM model contains 70 branches and 53 nodes and is outlined in Appendix B. It combines the QLD, NSW, VIC, SA and TAS state modules. The state module linking is via the following inter-state Interconnectors: QNI (line 11) and Directlink (line 14) linking Queensland and New South Wales; Tumut-Murray (line 35), Tumut-Dederang (line 36) and Tumut-Regional Victoria (line 37) linking New South Wales and Victoria; Heywood (line 49) and MurrayLink (line 50) linking Victoria and South Australia; and Basslink (line 42) linking Victoria and Tasmania. In accordance with the DC OPF framework utilized in the model, the High Voltage DC (HVDC) Interconnectors Directlink, Murraylink and Basslink are modelled as 'quasi AC' links with power flows being determined by reactance and thermal MW rating values only.

The major power flow pathways in the model reflect the major transmission pathways associated with 275, 330, 500/330/220, 275 and 220 KV transmission branches in Queensland, New South Wales, Victoria, South Australia and Tasmania, respectively. Key transmission data required for the transmission grid in the model relate to an assumed base voltage value, base apparent power, branch connection and direction of flow information, maximum thermal rating of each transmission branch (in MW's) and an estimate of its reactance value (in ohms). Base apparent power is set to 100 MVA, an internationally recognized value. Thermal ratings of transmission lines and reactance values were supplied by the Queensland, New South Wales and Tasmania transmission companies Powerlink, Transgrid, and Transend. For Victoria and South Australia, the authors also used values based on AEMO Equipment ratings data provided in files located at (http://www.aemo.com.au/Electricity/Data/Network-Data/Transmission-Equipment-Ratings).

It should be noted that these latter values were defined in the AEMO files in terms of MVA values. We convert these values to MWs assuming a power factor of unity. As such, the MW values used in the modeling correspond exactly to the MVA values listed in the source AEMO data files. We also utilized information in the AEMO equipment ratings files to accommodate differences in maximum thermal ratings between summer and winter. Typically, the maximum MW thermal capacity rating of transmission lines is greater in magnitude in winter than in summer because of the lower temperatures occurring in winter when compared to summer. Our modelling takes explicit account of this by using different thermal MW capacity values in summer and winter. We also assume that reactance is unaffected by temperature, but instead, is primarily determined by the alloy used in the transmission lines' conductors. This assumption permits the use of a constant value for the reactance on each branch.

In Appendix B, the direction of flow on a transmission branch (e.g. line) connecting two nodes is defined as a 'positive' flow if the power flows from the lower numbered node to the higher numbered node. For example, for line 1 connecting Far North Queensland (node 1) and the Ross node (node 2), power flowing from Far North Queensland to Ross one line 1 would have a positive sign while power flowing on line 1 from Ross to Far North Queensland would have a negative sign. The latter type of power flow is termed 'reverse' direction flow. In the ANEM model, it is possible to accommodate power flows in the positive and reverse direction having different thermal limits as well as varying between summer and winter.

C.2.2 Demand-side agents in the ANEM model: LSEs

A LSE is an electric utility that has an obligation to provide electrical power to end-use consumers (residential, commercial or industrial). The LSE agents purchase bulk power in the wholesale power market each day to service customer demand (called load) in the downstream retail market, thereby linking the wholesale power market and retail market. We assume that downstream retail demands serviced by the LSEs exhibit negligible price sensitivity, reducing to daily supplied load profiles which represents the real power demand (in MWs) that the LSE has to service in its downstream retail market for each hour of the day. LSEs are also modelled as passive entities who submit daily load profiles to the ISO without strategic considerations (Sun & Tesfatsion 2007b).

The revenue received by LSEs for servicing these load obligations are regulated to be a simple 'dollar mark-up' based retail tariff. For example, in Queensland, the State Government regulates retail tariffs that are payable by most residential customers. Prior to July 2009, for example, this amounted to 14.4c/KWh (excluding GST) which, in turn, translated into a retail tariff of $144/MWh. Thus, in the current set-up, LSEs are assumed to have no incentive to submit price-sensitive demand bids into the market.

The hourly regional load data for Queensland and New South Wales required by the model was derived using regional load traces supplied by Powerlink and Transgrid. This data was then re-based to the state load totals published by AEMO for the 'QLD1' and 'NSW1' markets (available at http://www.aemo.com.au/data/price_demand.html). For the other three states, the regional shares were determined from terminal station load forecasts associated with summer peak demand (and winter peak demand, if available) contained in the annual planning reports published by the transmission companies Transend (Tasmania), Vencorp (Victoria) and ElectraNet (South Australia). These regional load shares were then interpolated to a monthly based time series using a cubic spline technique and these time series of monthly shares were then multiplied by the 'TAS1', 'VIC1' and 'SA1' state load time series published by AEMO in order to derive the regional load profiles for Tasmania, Victoria and South Australia.

It should be recognised that the demand concept underpinning the State totals published by AEMO and used in the modelling is a net demand concept related conceptually to the output of scheduled and semi-scheduled generation, transmission losses and large independent loads directly connected to the transmission grid. As such, this net demand concept can be viewed as being calculated from gross demand, after contributions from small scale solar PV and both small scale and large scale non-scheduled generation (including wind, hydro and bagasse generation) has been netted out to produce the net demand concept used in the modelling.

C.2.3 Supply-side agents in the ANEM model: generators

Generators are assumed to produce and sell electrical power in bulk at the wholesale level. Each generator agent is configured with a production technology with assumed attributes relating to feasible production interval, total cost function, total variable cost function, fixed costs (pro-rated to a dollar per hour basis) and a marginal cost function. Depending upon plant type, a generator may also have start-up costs. Each generator also faces MW ramping constraints that determine the extent to which real power production levels can be increased or decreased over the next hour within the hourly dispatch horizon. Production levels determined from the ramp up and ramp down constraints must fall within the minimum and maximum thermal MW capacity limits confronting each generator.

The MW production and ramping constraints are defined in terms of 'energy sent out', i.e. the energy available to service demand. In contrast, variable costs and carbon emissions are calculated from the 'energy generated' production concept which is defined to include energy sent out plus a typically small amount of additional energy that is produced internally as part of the power production process. The variable costs of each generator are modelled as a quadratic function of hourly real energy produced by each generator. The marginal cost function is calculated as the partial derivative of the quadratic variable cost function with respect to hourly energy produced, producing a marginal cost function that is linear (upward sloping) in hourly real energy production of each generator (Sun & Tesfatsion 2007b).

The variable cost concept underpinning each generator's variable cost incorporates fuel, variable operation and maintenance (VO&M) costs and carbon cost components. The fuel, VO&M and carbon emissions/cost parameterisation was determined using data published in ACIL Tasman (2009) for thermal plant and from information sourced from hydro generation companies for hydro generation units. A formal derivation of the various cost components is outlined in greater detail in Appendix A of Wild, Bell and Foster (2012).

C.2.4 Passive hedging strategy incorporated in the ANEM model

Both theory and observation suggest that financial settlements based on market structures similar to that implemented in the NEM expose market participants to the possibility of extreme volatility in spot prices encompassing price spike behaviour (typically of short duration) or sustained periods of low spot prices. These impacts pose significant danger to the bottom line of both LSEs and generators respectively, requiring both types of agents to have long hedge cover positions to protect their financial viability.

In the ANEM model, a key decision for both types of agents is when to activate long cover to protect their bottom lines from the consequences of consistently high (low) spot prices – key determinants of 'excessively' high costs ('excessively' low revenues) faced by LSEs and generators, respectively. Failure to do so could pose serious problems for the continued financial solvency of market participants. The form of protection adopted in the model is a 'collar' instrument between LSEs and generators which is activated whenever spot prices rise above a ceiling price (for LSEs) or falls below a price floor (for generators). If the price floor applicable to generators is set equal to the generators long run marginal cost than generator long run revenue recovery can be implemented through the hedge instrument.

It is assumed that both LSEs and generators pay a small fee (per MWh of energy demanded or supplied) for this long hedge cover, irrespective of whether long cover is actually activated. Thus, the small fee acts like a conventional premium payment in real options theory. If the spot price is greater than the price floor applicable to generator long cover and below the price ceiling applicable for LSE long cover, than no long cover is activated by either type of agent although the fee payable for the long cover is still paid by both types of agents.

C.3 DC OPF solution algorithm used in the ANEM model

Optimal dispatch, wholesale prices and power flows on transmission lines are determined in the ANEM model by a DC OPF algorithm. The DC OPF algorithm utilised in the model is that developed in Tesfatsion and Sun (2007a) and involves representing the standard DC OPF problem as an augmented strictly convex quadratic programming (SCQP) problem, involving the minimization of a positive definite quadratic form subject to linear equality and inequality constraints. The augmentation entails utilising an objective function that contains quadratic and linear variable cost coefficients and branch connection and bus admittance coefficients. The solution values are the real power injections and branch flows associated with the energy production levels for each generator and voltage angles for each node.

We use the Mosek Optimisation Software (http://www.mosek.com) which exploits direct sparse matrix methods and utilises a convex quadratic programming algorithm based on the interior point algorithm to solve the DC OPF problem within the model.

The DC OPF algorithm employed in the ANEM model, incorporating the constraint format used by Mosek for the inequality constraints, is:

- Minimize generator-reported total variable cost and nodal angle differences

$$\sum_{i=1}^{I}\left[A_i P_{G_i} + B_i P_{G_i}^2\right] + \pi\left[\sum_{I_m \in BR}\delta_m^2 + \sum_{km \in BR,\, k\geq 2}\left[\delta_k - \delta_m\right]^2\right],$$

with respect to real-power production levels and voltage angles

$P_{G_i},\ i = 1,...,I;\ \ \delta_k,\ k = 2,...,K,$ subject to

- Real power balance (equality) constraint for each node $k = 1,...,K$ (with $\delta_1 \equiv 0$):

$$0 = PLoad_k - PGen_k + PNetInject_k\ ,$$

Where:

▪ $PLoad_k = \sum_{j \in J_k} P_{L_j}$ (e.g. aggregate power take-off at node k),

▪ $PGen_k = \sum_{i \in I_k} P_{G_i}$ (e.g. aggregate power injection at node k),

▪ $PNetInject_k = \sum_{km\ or\ mk \in BR} F_{km}$,

  ▪ $F_{km} = B_{km}\left[\delta_k - \delta_m\right]$ (e.g. real power flows on branches connecting nodes 'k' and 'm').

  ▪

- Real power thermal (inequality) constraints for each branch $km \in BR$ $k = 1,...,K$

- (with $\delta_1 \equiv 0$):

$F_{km} \geq -F_{km}^{UR}$, (lower bound constraint: reverse direction MW branch flow limit)

$F_{km} \leq F_{km}^{UN}$, (upper bound constraint: normal direction MW branch flow limit).

- Real-power production (inequality) constraints for each generator $i = 1,...,I$:

  $P_{G_i} \geq P_{G_i}^{LR}$, (lower bound constraint: lower hourly MW thermal ramping limit)

  $P_{G_i} \leq P_{G_i}^{UR}$ (upper bound constraint: upper hourly MW thermal ramping limit),

  Where:

  $P_{G_i}^{LR} \geq P_{G_i}^{L}$, (lower hourly thermal ramping limit ≥ lower thermal MW capacity limit)

  and

  $P_{G_i}^{UR} \leq P_{G_i}^{U}$ (upper hourly thermal ramping limit ≤ upper thermal MW capacity limit).

'U' = upper limit and 'L' = lower limit, A_i and B_i are linear and quadratic cost coefficients from the variable cost function. P_{G_i} is real (MW) power production level of generator 'i'. δ_k and δ_m are the voltage angles at nodes 'k' and 'm' (measured in radians). Parameter π is a positive soft penalty weight on the sum of squared voltage angle differences. Variables F_{km}^{UN} and F_{km}^{UR} are the (positive) MW thermal limits associated with real power flows in the 'normal' and 'reverse' direction on each connected transmission branch $km \in BR$.

The linear equality constraint refers to a nodal balance condition which requires that, at each node, power take-off (by LSEs located at that node) equals power injection (by generators located at that node) and net power transfers from other nodes on 'connected' transmission branches. On a node by node basis, the shadow price associated with this constraint gives the LMP (i.e. regional wholesale spot price) associated with that node. The linear inequality constraints ensure that real power transfers on connected transmission branches remain within permitted 'normal' and 'reverse' direction thermal limits and the real power produced by each generator remains within permitted lower and upper thermal MW capacity limits while also meeting hourly MW ramp up and ramp down generator production limits.

C.4 Practical implementation considerations

The solution algorithm employed in all simulations involves applying the 'competitive equilibrium' solution. This means that all generators submit their true marginal cost coefficients and no strategic bidding is allowed, permitting assessment of the true cost of generation and dispatch. We also assume that all thermal generators are available to supply power during the whole period under investigation. This rules out the possibility where allowing for planned or unscheduled outages in thermal generators would be expected to increase costs and prices above what is produced when all thermal plant is assumed to be available to supply power because it acts to constrain the least cost supply response available to meet prevailing demand.

Therefore, the methodological approach underpinning modelling is to produce 'as if' scenarios. In particular, we do not try to emulate actual generator bidding patterns for the years in question. Our objective is to investigate, in an *ideal* setting, how the true cost of power supply changes for changes in regional demand profiles associated with climate change and variation in carbon price, and how the resulting changes in demand and the relative cost of supply might influence dispatch patterns and power flows on transmission branches, when compared to a '*Business-As-Usual*' (BAU) scenario.

In order to make the model response to the various scenarios more realistic, we have taken account of the fact that baseload and intermediate coal and gas plant typically have 'non-zero' must run MW capacity levels termed minimum stable operating levels. These plants cannot be run below these specified MW capacity levels without endangering the long term productive and operational viability of the plant itself or violating statutory limitations relating to the production of pollutants and other toxic substances.

Because of the significant run-up time needed to go from start-up to a position where coal-fired power stations can actually begin supplying power to the grid, all coal plants were assumed to be synchronized with the grid so they can supply power. Thus, their minimum stable operating limits were assumed to be applicable for the whole period being investigated and they do not face start-up costs. Gas plants, however, have very quick start-up characteristics and can be synchronized with the grid and be ready to supply power typically within a half hour period of the decision to start-up. Therefore, in this case, the start-up decision and fixed start-up costs can accrue within the dispatch period being investigated.

Two approaches to modelling gas plant were adopted depending upon whether the gas plant could reasonably be expected to meet baseload or intermediate production duties or just peak load duties. If the gas plant was capable of meeting baseload or intermediate production duties, the plant was assigned a non-zero minimum stable operating capacity. In contrast, a peak gas plant was assumed to have a zero minimum stable operating capacity. Furthermore, if the baseload/intermediate gas plant was a gas thermal or NGCC plant, it was assumed to offer to supply power for a complete 24 hour period, thus, the minimum stable operating capacity was applicable for the whole 24 hour period and these plants did not face start-up costs. In contrast, many of the intermediate OCGT plant were assumed to only offer to supply power during the day. In this case, the minimum stable operating capacities were only applicable for those particular hours of the day and these plants faced the payment of fixed start-up costs upon start-up.

Details of the minimum stable operating capacities assumed for coal and intermediate gas plant are listed in Table C-1 and Table C-2, together with details about their assumed operating time, whether start-up costs were liable and, if so, what values were assumed for these particular costs.

It should be noted that there was some commissioning and de-commissioning of thermal generation plant during the period under investigation which was accommodated in the modelling. Specifically, the following plants were commissioned:

- Condamine, unit 3 in 2010-11;
- Darling Downs, all units in 2010-11;
- Yarwun in 2010-11; and
- Mortlake, all units in 2011-12.

The following generation plants were assumed to be de-commissioned:

- Swanbank B:
  - two units in 2010-11;
  - one unit in 2011-12;
  - last unit in 2012-13;

- Collinsville, all units in 2012-13;
- Munmorah, all units in 2012-13;
- Energy Brix, units 3-5 in 2012-13;
- Energy Brix, units 1-2 in 2013-14; and
- Playford B, all units in 2012-13.

While we have accommodated the permanent plant closures listed above (including Playford B which we have assumed will not be operated again because of its age), we have not included any of the more temporary plant closures associated with Tarong, Wallerarang C, Yallourn or Northern power stations which have been recently announced.

We have also fixed the generation structure used in simulations for the period 2009-10 to 2030-31 to the structure listed in Appendix B. In particular, we did not attempt to include any future proposed projects in the analysis because there is currently too much uncertainty over both the status and timing of many proposed projects. This uncertainty principally reflects three factors. The first relates to financial uncertainty over future gas prices once the eastern seaboard CSG/LNG projects begin to operate from 2014-15. The second factor relates to the fall in average demand experienced widely throughout the NEM over the last couple of years which affects the viability of baseload generation proposals as well as the future commissioning date of new project proposals. The third source of uncertainty is regulatory and political uncertainty about the future of both the recently implemented carbon tax scheme and renewable energy certificate scheme which affects the financial viability of gas and renewable generation project proposals, in particular. Therefore, given the generation set available for the ANEM model simulations, our modelling is clearly focused on assessing the supply response of the current generation fleet to the consequences of climate change.

While all thermal generators were assumed to be available to supply power, certain assumptions were imposed in relation to the availability of hydro generation units. It should also be noted that non-scheduled wind generation was excluded in the modelling because of data unavailability. The dispatch of the thermal plant was optimised around the assumed availability patterns for the hydro generation units. In determining the availability patterns for hydro plant, we assumed that water supply for hydro plant was not an issue. This approach also reflects the approach adopted in

Chapter 5 where the primary impact of climate change operating on electricity demand was through the impact of increases in temperature. If water supply issues or hydro unit availability were constraining factors, as was actually the case in 2007, for example, this would increase the cost and prices obtained from simulations because the cost of supply offers of hydro plant would be expected to increase significantly.

Because of the prominence of hydro generation in Tasmania, some hydro units were assumed to offer capacity over the whole year with account being taken off the ability of hydro plant to meet base load, intermediate or peak load production duties. For pump-storage hydro units such as Wivenhoe and Shoalhaven, the pump mode was activated by setting up a pseudo LSE located at the Morton North and Wollongong nodes (see Appendix B for further details). The combined load requirements for pump actions of all Wivenhoe and Shoalhaven hydro units were combined into a single load block determined by the model from unit dispatch records of these generators from the previous day and placed in the relevant pseudo LSEs. In both cases, the pump actions are assumed to occur in off-peak periods when the price (cost to hydro units) of electricity is lowest.

For all hydro plants, hydro generator supply offers were based on long run marginal cost coefficients. These coefficients take into account the need to meet fixed costs including capital and operational expenses and are often significantly larger in magnitude than corresponding short run marginal cost coefficients. For mainland hydro plant, supply was tailored to peak load production. Thus, long run marginal cost estimates were obtained for much lower annual capacity factors (ACF) than would be associated with hydro plant fulfilling base load or intermediate production duties, thus producing higher long run marginal cost coefficients. Moreover, the ACF was reduced for each successive hydro turbine making up a hydro plant resulting in an escalating series of marginal cost coefficient bids for each successive turbine. In general, the lowest marginal cost coefficient shadowed peak load OCGT plant while other turbines supply offers could be significantly in excess of cost coefficients associated with more expensive peak load gas or diesel plant. This approach essentially prices the social cost of water usage within successive turbines of a hydro plant as an increasingly scarce commodity.

A key consideration governing the decision to use long run marginal cost coefficients to underpin the supply offers of hydro generation plant is the predominance of such generators in Tasmania. With the absence of other major forms of thermal based generation in Tasmania and limited native load demand and export capability into Victoria, it is likely that nodal pricing, based on short run marginal costs, would not be sufficient to cover operational and capital costs. Supply offers based on long run marginal costs, however, ensure that average price levels are sufficient to cover these costs over the lifetime of a hydro plant's operation. We also assumed that the minimum stable operating capacity for all hydro plants was zero and that no start-up costs were incurred when the hydro plants begin supplying power to the grid. The hydro plant is also assumed to have a very fast ramping capability.

Table C-1 Minimum stable operating capacity limits for coal plant, assumed operating time and start-up cost status

Generation Plant	Minimum Stable Operating Capacity Level % of total MW Capacity (sent out basis)	Assumed Operating Time Hours	Start-up Status/Cost Yes/No	Assumed Start-up Cost $/MW per start
Black Coal – QLD				
Collinsville	40.00	24	No	$160.00
Stanwell	40.00	24	No	$ 80.00
Callide B	40.00	24	No	$ 80.00
Callide C	40.00	24	No	$ 80.00
Gladstone	31.00	24	No	$ 90.00
Tarong North	40.00	24	No	$ 70.00
Tarong	40.00	24	No	$ 80.00
Kogan Creek	40.00	24	No	$ 40.00
Millmerran	40.00	24	No	$ 70.00
Swanbank B	26.00	24	No	$150.00
Black Coal – NSW				
Liddle	40.00	24	No	$ 50.00
Redbank	40.00	24	No	$150.00
Bayswater	40.00	24	No	$ 45.00
Eraring	40.00	24	No	$ 45.00
Munmorrah	40.00	24	No	$ 80.00
Vales Point	40.00	24	No	$ 45.00
Mt Piper	40.00	24	No	$ 45.00
Wallerawang	40.00	24	No	$ 50.00
Black Coal - SA				
Playford B	40.00	24	No	$150.00
Northern	55.00	24	No	$ 90.00
Brown Coal – VIC				
Loy Yang A	60.00	24	No	$ 50.00
Loy Yang B	60.00	24	No	$ 50.00
Energy Brix	60.00	24	No	$160.00
Hazelwood	60.00	24	No	$ 95.00
Yallourn	60.00	24	No	$ 80.00
Anglesea	60.00	24	No	$150.00

Table C-2 Minimum stable operating capacity limits for baseload and intermediate gas plant, assumed operating time and start-up cost status

Generation Plant	Minimum Stable Operating Capacity Level % of total MW Capacity (sent out basis)	Assumed Operating Time Hours	Start-up Status/Cost Yes/No	Assumed Start-up Cost $/MW per start
QLD				
Townsville	50.00	24	No	$100.00
Braemar 1	50.00	13 daytime only	Yes	$100.00
Braemar 2	50.00	13 daytime only	Yes	$100.00
Condamine	50.00	24	No	$50.00
Darling Downs	50.00	24	No	$50.00
Swanbank E	50.00	24	No	$ 50.00
NSW				
Smithfield	60.00	24	No	$100.00
Uranquinty	50.00	13 daytime only	Yes	$ 90.00
Tallawarra	50.00	24	No	$ 40.00
VIC				
Newport	65.00	13 daytime only	Yes	$ 40.00
SA				
Ladbroke Grove	50.00	13 daytime only	Yes	$110.00
Pelican Point	50.00	24	No	$ 70.00
New Osborne	76.00	24	No	$ 80.00
Torrens Island A	50.00	13 daytime only	Yes	$ 80.00
Torrens Island B	50.00	24	No	$ 65.00

In the ANEM model simulations performed for this project, we have also adopted an ‘n’ transmission configuration scenario. This approach involves applying the MW thermal limits determined from the sum of all individual transmission line thermal ratings in the group of transmission lines connecting two nodes. This approach effectively assumes no line outages occur and that the transmission lines are all in good working condition. For example, the capacity of each line is not unduly constrained to capacities below its rated capacity when all other transmission lines are operating at their maximum capacity. As such, this approach represents, from the perspective of operational constraints of the transmission network, an *ideal* setting, matching the approach we also adopted in relation to thermal and hydro generation unit availability.

The approach adopted in this project can be contrasted with the more realistic 'n-1' transmission configuration scenario which typically involves subtracting the largest individual line from the group connecting nodes. This latter approach is linked to reliability considerations that ensure that things do not go ‘pear shaped’ if the largest single line is lost, and as such, is a more realistic operational setting. Of course, under the ‘n-1’ scenario, branch congestion is more likely to occur than is the case with the ‘n’ scenario adopted in the modelling for this project. It also follows, however, that in the ‘n’ scenario formulation, evidence of branch congestion is a more serious constraint because it is not possible to ‘juggle’ loads upon a group of connected transmission branches to alleviate congestion as might be possible under an ‘n-1’ scenario especially in a short-term emergency setting. Thus, in the current simulations, any branch congestion can only be really alleviated by building additional transmission lines or up-grading the thermal ratings of existing transmission lines and congested transmission branches would point to structural deficiencies in the current transmission grid.

The main reason we adopted the ‘n’ transmission configuration scenario was because of the length of the time interval involved with the project which goes out to 2030-31. As such, we are sacrificing some operational realism in the near turn but also recognising that the current ‘n’ scenario might well become an ‘n-1’ scenario towards the end of the simulation time horizon if additional transmission lines were to be added and also where climate change impacts are likely to be the most pressing.

D VALIDATING THE ANEM MODEL FOR THIS PROJECT

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This appendix presents the results from Chapter 7 research question 1 as they are too numerous to include in the main text. The appendix provides a comparative assessment of the ANEM models performance using 2009-10 actual and predicted regional demand profiles from Chapter 5 to answer the first research question:

1. *Compare the spot price, energy generated, carbon emissions and transmission congestion using projected and actual demand for the base weather year 2009-10.*

In this Appendix, we will outline in subsequent sections, the methodology and performance metrics used to assess ANEM model performance. We then provide detailed results to support the claim that the ANEM model does produces very similar results using the actual and projected demand for 2009-10, with and without a carbon price.

D.1 Methodology

The objective of this Appendix is to assess the extent to which ANEM model output associated with both the actual and predicted 2009-10 regional demands projections coincide. If the ANEM output metrics coincide to a close degree, this provides further anecdotal evidence that the regional demand prediction methodology employed in Sections 5.2 and 5.3 were successful in capturing the main dynamic characteristics of the actual regional demand data. Furthermore, if the output measures are in close agreement, we can also have confidence that the ANEM model produces a stable solution. This, in turn, would mean that we can have confidence to use the ANEM model to make the comparisons between the years 2009-10 and 2030-31 based on the demand projections for those years.

The methodology to be employed in this section is to assess the closeness of ANEM model output metrics using what is essentially a qualitative approach. It involves running the ANEM model using both demand profiles and calculating desired output performance metrics. These output metrics are placed in tables in which the 'predicted' row contains the results associated with the predicted 2009-10 regional demand profiles. Similarly, the row 'actual' contains the results associated with the actual 2009-10 regional demand profiles.

Depending upon output metric, these two rows will have the same data structures and the values can be visually inspected to ascertain how closely they coincide with each other. This approach will be shown to be sufficient for our purposes in demonstrating that the ANEM model produces similar results when using the actual and projected demand profiles for 2009-10.

In order to provide further quantitative clarification of the closeness of the results, we also calculate the per cent change between the values cited in the 'actual' and 'predicted' rows of the various panels relating to average price levels and volatility, production intensity rates, carbon emission levels and average branch flows on inter-state interconnectors and congested branches. We do not, however, apply the per cent change calculations to the average power flow results for intra-state transmission branches [i.e. to Panel (J)] of Table D-1 and Table D-2 in the results section below.

The per cent change calculations outlined in Table D-1 and Table D-2 below are calculated using the formula: %Change = [(actual – predicted)/predicted]*100, where 'actual' and 'predicted' denoted the values in the 'actual' and 'predicted' rows of the relevant panels in Table D-1 and Table D-2, respectively. Note, if both the actual and predicted values are zero, the difference is recorded as zero.

D.1.1 ANEM performance metrics

A number of different performance metrics are employed to assess ANEM model performance for the two different sets of regional demand profiles used for year 2009-10. These metrics are:

- average price levels by state;
- price volatility by state;
- production intensity rate by state for:
  - all generation;
  - coal generation;
  - gas generation; and
  - hydro generation.
- level of carbon emissions in 2009-10 by state for:
  - all generation;
  - coal generation; and
  - gas generation.
- average power flow as a proportion of thermal MW capacity limit on:
  - intra-state transmission lines; and
  - inter-state interconnectors.
- proportion of time congested in the year on congested transmission branches.

D.1.2 Calculation of performance metrics

The first set of metrics relate to average price levels by State and price volatility by State. The average price results reflect a spatial and temporal dimension. For each hourly dispatch interval in a given year, an average State price level was obtained by averaging across all relevant nodal prices within each State as indicated by the nodal structure contained in each State module outlined in Appendix B. The average annual price for each State was then obtained by averaging across the number of hours in each respective year. The average annual price for the NEM was then calculated by averaging across the five State average annual price levels. Note that all averaging operations performed involved simple arithmetic averaging and not some weighted average scheme, particularly in relation to obtaining the NEM averages.

The price volatility measure was calculated by taking the standard deviation of the spot price time series generated by the ANEM model for each node and then averaging these results across the nodes located within each state and across the states to obtain the NEM results.

To calculate production intensity rates, we calculate the average (MW) level of dispatch for each generator during the year and divide this value by the maximum thermal MW rating of each generator to express the average production level as a proportion of installed capacity. In order to obtain state-specific results, according to plant type, we averaged the results across the relevant categories of plant located in each state. Once again, NEM results were calculated by simple arithmetic averaging across the state results.

To calculate the level of carbon emissions in 2009-10, we sum daily $C0_2$ emissions times series produced by the ANEM model for each generator located at a node within each State over each year. The aggregate State figures were then obtained by summing the former figures across all generators within the State and by fuel type to calculate the State aggregate carbon emission totals for the year and by fuel type. The NEM aggregate was calculated by totalling the aggregate State carbon emission totals.

Power flows on transmission lines are expressed in terms of average MW power flows. These results were calculated by determining the average MW power flow for each year on each transmission branch and expressing this as a proportion of that transmission branches maximum thermal MW rating. This output metric is calculated for all transmission branch including both intra-state and inter-state branches.

Branch congestion is defined as arising when the MW power transfer on the transmission branch (in either a positive or reverse direction) is equal to the transmission branches rated MW thermal limit. In the context of this definition and given how average power flows are expressed as a proportion of maximum thermal MW capacity, an increase in the proportion values would be indicative of a tendency towards a more utilised network, in qualitative terms.

In order to quantitatively calculate the degree of branch congestion, we calculate the number of times within all of the dispatch intervals in a year that actual power flows equates with the appropriate MW thermal limit and express this number as a proportion of the total number of dispatch intervals in the year.

D.2 Results

The results associated with the output metrics mentioned above are presented in the next two sections. The first set of results will detail results from ANEM simulations in which the carbon price was set to $0/$tC0_2$ (i.e. no carbon price signal). The second set of results will be reported in the following section and will relate to simulations in which the carbon price was set to $23/$tC0_2$.

D.2.1 ANEM simulation results for 2009-10 in the absence of a carbon price

As mentioned above, the first set of results are outlined in Table D-1 and are for ANEM model simulations for 2009-10 using actual and projected 2009-10 demand profiles and no carbon price.

Table D-1 Difference in ANEM model output by using predicted and actual regional demand profiles with no carbon price for 2009-10

Panel (A) Wholesale price levels ($/MWh)

Demand	QLD	NSW	VIC	SA	TAS	NEM
predicted	16.20	18.28	48.69	32.67	31.31	29.43
actual	16.20	18.28	49.03	32.81	31.31	29.53
%Change	-0.03	0.00	0.71	0.44	0.01	0.33

Panel (B) Volatility in wholesale prices (Standard deviation)

Demand	QLD	NSW	VIC	SA	TAS	NEM
predicted	2.46	5.52	435.15	157.28	1.91	120.47
actual	2.44	5.51	437.38	158.46	1.91	121.14
%Change	-0.94	-0.16	0.51	0.75	0.18	0.56

Panel (C) Generation production intensity rate: all generation (Proportion - average MW production level/MW capacity Limit)

Demand	QLD	NSW	VIC	SA	TAS
predicted	0.4391	0.3569	0.2749	0.2237	0.2081
actual	0.4390	0.3569	0.2749	0.2238	0.2082
%Change	-0.02	0.00	0.00	0.03	0.02

Panel (D) Generation production intensity rate: coal generation (Proportion - average MW production level/MW capacity Limit)

Demand	QLD	NSW	VIC	SA	NEM
predicted	0.6702	0.7429	0.8633	0.5830	0.7149
actual	0.6701	0.7429	0.8633	0.5832	0.7149
%Change	-0.02	0.00	0.00	0.03	0.00

Panel (E) Generation production intensity rate: gas generation (Proportion - average MW production level/MW capacity Limit)

Demand	QLD	NSW	VIC	SA	TAS	NEM
predicted	0.3207	0.3095	0.0333	0.2189	0.1000	0.1965
actual	0.3207	0.3095	0.0332	0.2189	0.1000	0.1965
%Change	0.00	0.00	-0.08	0.02	0.00	0.00

Panel (F) Generation production intensity rate: hydro generation (Proportion - average MW production level/MW capacity Limit)

Demand	QLD	NSW	VIC	TAS	NEM
predicted	0.0000	0.0002	0.0081	0.2189	0.0568
actual	0.0000	0.0002	0.0081	0.2190	0.0568
%Change	zero	-1.33	0.45	0.02	0.03

Panel (G) Level of carbon emissions in 2009-10: all generation ($tC0_2$)

Demand	QLD	NSW	VIC	SA	TAS	NEM
predicted	5.38E+07	6.89E+07	6.24E+07	9.33E+06	3.79E+05	1.95E+08
actual	5.38E+07	6.89E+07	6.24E+07	9.34E+06	3.79E+05	1.95E+08
%Change	-0.0147	-0.0007	-0.0002	0.0061	0.0000	-0.0041

Panel (H) Level of carbon emissions in 2009-10: coal generation ($tC0_2$)

Demand	QLD	NSW	VIC	SA	NEM
predicted	5.12E+07	6.69E+07	6.14E+07	4.88E+06	1.84E+08
actual	5.12E+07	6.69E+07	6.14E+07	4.88E+06	1.84E+08
%Change	-0.0151	-0.0005	0.0005	0.0238	-0.0035

Panel (I) Level of carbon emissions in 2009-10: gas generation ($tC0_2$)

Demand	QLD	NSW	VIC	SA	TAS	NEM
predicted	2.60E+06	2.02E+06	1.06E+06	4.45E+06	3.79E+05	1.05E+07
actual	2.60E+06	2.02E+06	1.06E+06	4.45E+06	3.79E+05	1.05E+07
%Change	-0.0076	-0.0091	-0.0440	-0.0127	0.0000	-0.0135

Panel (J) Average power flow as a proportion of thermal capacity limit: intra-state transmission lines (average MW power flow/MW capacity Limit of transmission branch)

Demand	Line 1	Line 2	Line 3	Line 4	Line 5	Line 6	Line 7	Line 8
predicted	0.2464	0.2204	0.2092	0.4753	0.1005	0.1218	0.0800	0.0330
actual	0.2463	0.2202	0.2091	0.4755	0.1005	0.1217	0.0799	0.0330

Demand	Line 9	Line 10	Line 12	Line 13	Line 15	Line 16	Line 17	Line 18
predicted	0.2997	0.3196	0.1661	0.1743	0.0620	0.3634	0.2812	0.1932
actual	0.2997	0.3195	0.1661	0.1743	0.0619	0.3637	0.2815	0.1933

Demand	Line 19	Line 20	Line 21	Line 22	Line 23	Line 24	Line 25	Line 26
predicted	0.6522	0.5459	0.2177	0.0589	0.3308	0.3412	0.2691	0.1425
actual	0.6523	0.5460	0.2177	0.0589	0.3309	0.3412	0.2692	0.1426

Demand	Line 27	Line 28	Line 29	Line 30	Line 31	Line 32	Line 33	Line 34
predicted	0.1834	0.1801	0.0056	0.4178	0.4643	0.4756	0.3610	0.2186
actual	0.1835	0.1802	0.0057	0.4180	0.4644	0.4758	0.3611	0.2187

Demand	Line 38	Line 39	Line 40	Line 41	Line 43	Line 44	Line 45	Line 46
predicted	0.2363	0.1045	0.2995	0.3118	0.0364	0.5517	0.4015	0.8651
actual	0.2365	0.1046	0.2996	0.3118	0.0364	0.5517	0.4015	0.8651

Demand	Line 47	Line 48	Line 51	Line 52	Line53	Line 54	Line 55	Line 56
predicted	0.1058	0.2082	0.0308	0.0990	0.0074	0.1488	0.0880	0.2130
actual	0.1058	0.2081	0.0308	0.0990	0.0074	0.1488	0.0880	0.2130

Demand	Line 57	Line 58	Line 59	Line 60	Line 61	Line 62	Line 63	Line 64
predicted	0.1471	0.2631	0.0432	0.4493	0.0904	0.3171	0.1175	0.0000
actual	0.1472	0.2631	0.0432	0.4494	0.0904	0.3172	0.1175	0.0000

Demand	Line 65	Line 66	Line 67	Line 68	Line 69	Line 70
predicted	0.0183	0.1285	0.0123	0.0275	0.1490	0.2965
actual	0.0183	0.1285	0.0123	0.0274	0.1490	0.2966

Panel (K) Average power flow as a proportion of thermal capacity limit: inter-state interconnectors (average MW power flow/MW capacity Limit of transmission branch)

Demand	Line 11	Line 14	Line 35	Line 36
Name	QNI	DirectLink	Tum-Mur	Tum-Ded
predicted	0.8862	0.5367	0.2990	0.1926
actual	0.8865	0.5372	0.2992	0.1927
%Change	0.04	0.09	0.06	0.06

Demand	Line 37	Line 42	Line 49	Line 50
Name	Tum-RVc	Basslink	Heywood	Murraylk
predicted	0.6277	0.9997	0.1212	0.1318
actual	0.6280	0.9997	0.1212	0.1318
%Change	0.05	0.00	-0.01	0.06

Panel (L) Proportion of time congested (number of dispatch intervals (e.g. hours) in the year that branch flow equals maximum thermal limit of transmission branch/total number of dispatch intervals (e.g. hours) in the year)

Demand	Line 11	Line 31	Line 37	Line 42	Line 46	Line 50
Branch	QNI	Mar-Yas	Tum-RVc	Basslink	Haz-Yall	Murraylk
predicted	0.6115	0.0005	0.2911	0.9969	0.9991	0.0762
actual	0.6121	0.0000	0.2916	0.9968	0.9991	0.0761
%Change	0.10	-100.00	0.19	-0.01	0.00	-0.16

D.2.2 ANEM simulation results for 2009-10 for a carbon price of $23/tC0$_2$

The next set of results we consider are for ANEM model simulations involving a carbon price signal of $23/tC0$_2$. These outcomes are reported in Table D-2.

Table D-2 Difference in ANEM model output by using predicted and actual regional demand profiles with a carbon price of $23/tC02 for 2009-10

Panel (A) Wholesale price levels ($/MWh)

Demand	QLD	NSW	VIC	SA	TAS	NEM
predicted	37.48	39.32	74.79	52.96	36.91	48.29
actual	37.48	39.32	74.56	52.90	36.91	48.23
%Change	-0.01	-0.01	-0.30	-0.12	0.01	-0.12

Panel (B) Volatility in wholesale prices (Standard deviation)

Demand	QLD	NSW	VIC	SA	TAS	NEM
predicted	2.35	4.22	433.06	156.49	2.43	119.71
actual	2.34	4.20	431.77	156.03	2.43	119.36
%Change	-0.47	-0.34	-0.30	-0.29	0.27	-0.29

Panel (C) Generation production intensity rate: all generation (Proportion - average MW production level/MW capacity Limit)

Demand	QLD	NSW	VIC	SA	TAS
predicted	0.4439	0.3522	0.2378	0.2188	0.2901
actual	0.4438	0.3522	0.2378	0.2188	0.2901
%Change	-0.02	0.00	-0.01	0.00	0.02

Panel (D) Generation production intensity rate: coal generation (Proportion - average MW production level/MW capacity Limit)

Demand	QLD	NSW	VIC	SA	NEM
predicted	0.6791	0.7305	0.7400	0.5378	0.6718
actual	0.6789	0.7305	0.7400	0.5379	0.6719
%Change	-0.02	0.00	0.01	0.03	0.00

Panel (E) Generation production intensity rate: gas generation (Proportion - average MW production level/MW capacity Limit)

Demand	QLD	NSW	VIC	SA	TAS	NEM
predicted	0.3211	0.3093	0.0344	0.2195	0.1000	0.1969
actual	0.3211	0.3093	0.0343	0.2195	0.1000	0.1968
%Change	-0.01	-0.01	-0.21	-0.02	0.00	-0.02

Panel (F) Generation production intensity rate: hydro generation (Proportion - average MW production level/MW capacity Limit)

Demand	QLD	NSW	VIC	TAS	NEM
predicted	0.0000	0.0005	0.0083	0.3091	0.0795
actual	0.0000	0.0005	0.0082	0.3092	0.0795
%Change	zero	-0.97	-0.69	0.02	0.00

Panel (G) Level of carbon emissions in 2009-10: all generation ($tC0_2$)

Demand	QLD	NSW	VIC	SA	TAS	NEM
predicted	5.46E+07	6.86E+07	5.73E+07	9.12E+06	3.79E+05	1.90E+08
actual	5.46E+07	6.86E+07	5.73E+07	9.12E+06	3.79E+05	1.90E+08
%Change	-0.0168	0.0010	0.0053	0.0089	0.0000	-0.0024

Panel (H) Level of carbon emissions in 2009-10: coal generation ($tC0_2$)

Demand	QLD	NSW	VIC	SA	NEM
predicted	5.20E+07	6.66E+07	5.63E+07	4.65E+06	1.80E+08
actual	5.20E+07	6.66E+07	5.63E+07	4.65E+06	1.80E+08
% Change	-0.0171	0.0012	0.0064	0.0270	-0.0018

Panel (I) Level of carbon emissions in 2009-10: gas generation ($tC0_2$)

Demand	QLD	NSW	VIC	SA	TAS	NEM
predicted	2.60E+06	2.02E+06	1.05E+06	4.47E+06	3.79E+05	1.05E+07
actual	2.60E+06	2.02E+06	1.05E+06	4.47E+06	3.79E+05	1.05E+07
%Change	-0.0106	-0.0062	-0.0524	-0.0097	0.0000	-0.0132

Panel (J) Average power flow as a proportion of thermal capacity limit: intra-state transmission lines (average MW power flow/MW capacity Limit of transmission branch)

Demand	Line 1	Line 2	Line 3	Line 4	Line 5	Line 6	Line 7	Line 8
predicted	0.2464	0.2202	0.2093	0.5006	0.1271	0.1382	0.1045	0.0447
actual	0.2463	0.2201	0.2091	0.5008	0.1270	0.1381	0.1044	0.0447

Demand	Line 9	Line 10	Line 12	Line 13	Line 15	Line 16	Line 17	Line 18
predicted	0.3040	0.2987	0.1789	0.1800	0.0410	0.4182	0.3315	0.1735
actual	0.3039	0.2986	0.1789	0.1800	0.0409	0.4183	0.3317	0.1736

Demand	Line 19	Line 20	Line 21	Line 22	Line 23	Line 24	Line 25	Line 26
predicted	0.6834	0.5544	0.2091	0.0370	0.3096	0.3880	0.2681	0.1379
actual	0.6834	0.5545	0.2091	0.0369	0.3096	0.3880	0.2681	0.1380

Demand	Line 27	Line 28	Line 29	Line 30	Line 31	Line 32	Line 33	Line 34
predicted	0.1834	0.1950	0.0059	0.4382	0.4908	0.4980	0.3863	0.2398
actual	0.1835	0.1951	0.0058	0.4383	0.4909	0.4981	0.3864	0.2398

Demand	Line 38	Line 39	Line 40	Line 41	Line 43	Line 44	Line 45	Line 46
predicted	0.2618	0.1287	0.3140	0.3743	0.0421	0.5215	0.3911	0.8585
actual	0.2619	0.1287	0.3140	0.3743	0.0421	0.5215	0.3911	0.8586

Demand	Line 47	Line 48	Line 51	Line 52	Line53	Line 54	Line 55	Line 56
predicted	0.1064	0.1857	0.0321	0.1000	0.0069	0.1417	0.0689	0.2021
actual	0.1064	0.1857	0.0321	0.1000	0.0069	0.1418	0.0689	0.2022

Demand	Line 57	Line 58	Line 59	Line 60	Line 61	Line 62	Line 63	Line 64
predicted	0.1471	0.1952	0.1961	0.4493	0.0896	0.4971	0.3026	0.2103
actual	0.1471	0.1951	0.1961	0.4494	0.0896	0.4971	0.3027	0.2104

Demand	Line 65	Line 66	Line 67	Line 68	Line 69	Line 70
predicted	0.0731	0.3293	0.0484	0.1071	0.1366	0.5003
actual	0.0732	0.3293	0.0484	0.1071	0.1367	0.5003

Panel (K) Average power flow as a proportion of thermal capacity limit: inter-state interconnectors(average MW power flow/MW capacity Limit of transmission branch)

Demand	Line 11	Line 14	Line 35	Line 36
Name	QNI	DirectLink	Tum-Mur	Tum-Ded
predicted	0.9666	0.6342	0.3315	0.2134
actual	0.9669	0.6346	0.3316	0.2135
%Change	0.03	0.05	0.03	0.02

Demand	Line 37	Line 42	Line 49	Line 50
Name	Tum-RVc	Basslink	Heywood	Murraylk
predicted	0.6797	0.4866	0.1266	0.1689
actual	0.6798	0.4867	0.1265	0.1690
%Change	0.02	0.00	-0.01	0.03

Panel (L) Proportion of time congested (number of dispatch intervals (e.g. hours) in the year that branch flow equals maximum thermal limit of transmission branch/total number of dispatch intervals (e.g. hours) in the year)

Demand	Line 11	Line 31	Line 37	Line 42	Line 46	Line 50
Branch	QNI	Mar-Yas	Tum-RVc	Basslink	Haz-Yall	Murraylk
predicted	0.8166	0.0002	0.3366	0.0089	0.9148	0.0842
actual	0.8176	0.0000	0.3368	0.0089	0.9149	0.0840
%Change	0.11	-100.00	0.07	0.00	0.01	-0.27

D.3 Discussion

D.3.1 ANEM simulation results for 2009-10 without a carbon price

In general, inspection of each Panel of Table D-1 confirms the high degree of similarity in the output metrics obtained from simulations of the ANEM model using the actual and projected 2009-10 demand profiles when a carbon price signal is absent.

The four outputs from the ANEM model are discussed in turn:

- carbon emissions;
- energy produced by generation type;
- spot prices; and
- transmission line congestion.

D.3.1.1 Carbon emissions

The results obtained for the level of carbon emissions in 2009-10 display an extremely close degree of correspondence. The %Change values in Panels (G)-(I) of Table D-1 have been reported to four decimal places to demonstrate how very small the percentage difference actually is. In all cases across States and fuel types, the difference is less than 0.1 of one per cent and often much less than this value.

D.3.1.2 Energy produced by generator type

Apart from some variation in the production intensity rates of hydro generation, the other production intensity rates, by fuel type and State display extremely close agreement as can be discerned from inspection of Panels (C)-(F) of Table D-1, with the difference in production intensity rates being less than 0.1 of one per cent. Variation in production intensity rates for hydro generation in New South Wales was 1.3 per cent and 0.4 of a per cent in Victoria. These two results come from extremely small production intensity base rates of 0.0001 and 0.0081, respectively. Note that the concept of production intensity rate is defined in Section D.1.2. So, the average hydro production levels being such a small fraction of total hydro capacity ameliorates any concern over the higher per cent difference recorded for hydro generation.

D.3.1.3 Spot Price

Average spot prices:

Average spot price outcomes reported in Panel (A) of Table D-1 indicate very tight agreement between average price levels by State. Victoria experiences the largest difference with the percentage rate of change being in the order of 0.7 of one per cent. South Australia experiences the next largest difference corresponding to 0.4 of one per cent. The difference for all other states is below 0.1 of a per cent. The variation in the outcomes for the NEM is 0.3 of a per cent, primarily reflecting the contributions of Victoria and South Australia mentioned above.

Spot price volatility:

The spot price volatility by State outcomes reported in Panel (B) of Table D-1 indicates close agreement by State. The State experiencing the largest difference between spot price volatility results is Queensland with a percentage change result of 0.9 of one per cent. The next two States experiencing the largest difference in spot price volatility outcomes is South Australia (0.7 of a per cent), followed by Victoria (half a per cent). The difference in the outcomes for the NEM is 0.6 of one per cent, primarily reflecting the contributions of Queensland, South Australia and Victoria.

D.3.1.4 Line congestion

Average power flows

The results reported in Panels (J)-(K) of Table D-1 for average power flows on transmission branches demonstrate the similarity of the results across both simulations using actual and predicted demand. In qualitative terms, the largest difference in average power flows as a proportion of MW thermal capacity occurs on lines 16 and 17 for the intra-state transmission line outcomes reported in Panel (J). Appendix B shows the line numbers and terminal nodes. In quantitative terms, the difference in average powers flow on inter-state transmission lines reported in Panel (K) of Table D-1 are all less than 0.1 of one per cent. In qualitative terms, the inter-state interconnector experiencing the largest difference is Directlink (line 14) followed by QNI (line 11) and Tumut-Regional Victoria (line 37).

Measures of direct branch congestion

The outcomes relating to branch congestion are reported in Panel (L) of Table D-1. The transmission lines experiencing the largest difference in congestion outcomes are lines 37 (Tumut-Regional Victoria) and line 11 (QNI). Both of these branches are inter-state interconnectors. The difference in congestion results for these two transmission lines, however, is quite small in magnitude, being in the order of 0.2 and 0.1 of a per cent, respectively. Line 31 (Marulan-Yass) experiences a high percentage change in congestion outcomes. However, this result should be interpreted with caution because it is coming from an extremely small base congestion value of 0.0005. The incidence of congestion on this branch is extremely marginal and in fact does not show up in the simulation utilising the actual 2009-10 demand profile.

D.3.2 ANEM simulation results for 2009-10 for a carbon price of $23/tC$0_2$

In general, inspection of each Panel of Table D-2 confirms the high degree of similarity in the output metrics obtained from simulations of the ANEM model using the actual and projected 2009-10 demand profiles when a carbon price of $23/tC$0_2$ is present.

Recall that the four outputs from the ANEM model to be discussed in turn are:

- carbon emissions;
- energy produced by generation type;
- spot prices; and
- transmission line congestion.

D.3.2.1 Carbon emissions

The results obtained for the level of carbon emissions in 2009-10 also display a very close degree of correspondence. The %Change values in Panels (G)-(I) of Table D-2 indicate how very small the variation actually is. In all cases across states and fuel types, the difference is less than 0.1 of one per cent.

D.3.2.2 Energy produced by generator type

In a similar manner to the results in Section D.3.1.2, apart from some variation in the production intensity rates of hydro generation, the other production intensity rates, by fuel type and state display extremely close agreement. Variation in production intensity rates continue to be less than or equal to 0.1 of one per cent. A reduction in the magnitude of the difference in production intensity rate outcome for hydro generation in New South Wales to 1 per cent and an increase to 0.7 of one per cent for Victoria occurs when compared to the equivalent outcomes reported in Panel (F) of Table D-1. These two results still occur against a backdrop of extremely small production intensity base rates of 0.0003 and 0.0082. The average hydro production levels being such a small fraction of total hydro capacity would continue to ameliorate concern over these higher percentage difference rates for hydro generation.

D.3.2.3 Spot Price

Average spot prices:

The average price outcomes reported in Panel (A) of Table D-2 indicates a very close agreement by state. Increasing the carbon price from $0/tC0$_2$ to $23/tC0$_2$ reduced the difference between ANEM models spot price projection using projected and actual demand. This holds true for both average spot price and also spot price volatility. The percentage difference results still match those in Panel (A) of Table D-1 in qualitative terms. Victoria still experiences the largest increase with the percentage rate of change now being of a lower order of 0.3 of one per cent. South Australia experiences the next largest increase corresponding to 0.1 of one per cent.

Spot price volatility:

Spot price volatility by State outcomes reported in Panel (B) of Table D-2 also demonstrates close correspondence of spot price volatility outcomes by State. The state experiencing the largest increase between spot price volatility results is still Queensland with a percentage change result of half a per cent. The remaining States display similar difference outcomes of around 0.3 of a per cent. This result is qualitatively different from the results in Table D-1 Panel (B) in which South Australia and Victoria experienced more difference in spot price volatility outcomes than the other states, excluding Queensland.

D.3.2.4 Line congestion

Average power flows

The results reported in Panels (J)-(K) of Table D-2 for average power flows on transmission branches demonstrate the similarity of the results based on the actual and predicted demand. In qualitative terms, the percentage difference in average power flows on intra-state transmission lines appeared to diminish with a carbon price of \$23/t$C0_2$. In quantitative terms, the difference in average power flow on inter-state transmission lines reported in Panel (K) of Table D-2 are all still less than 0.1 of one per cent. In qualitative terms, the inter-state interconnector experiencing the largest increase is Directlink (line 14) followed by QNI (line 11).

Measures of direct branch congestion

The outcomes relating to branch congestion are reported in Panel (L) of Table D-2. The transmission line experiencing the largest increase in congestion outcomes is line 11 (QNI) with a percentage change result of around 0.1 of one per cent. The difference for line 31 (Tumut-Regional Victoria) has improved significantly over the result reported in Panel (L) of Table D-1, down from around 0.2 of a per cent to now under 0.1 of a per cent. Apart from line 31, the difference in congestion results continue to be quite small in magnitude, being less than or equal to 0.1 of one per cent. The remarks made about line 31 (Marulan-Yass) in Section D.3.1.4 continue to hold in all respects, ameliorating concern over the percentage difference result recorded for this particular transmission line.

E WHOLESALE SPOT PRICES

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This Appendix outlines the methodology and detailed results from ANEM model simulations based on the projected regional demand profiles for years 2009-10 to 2030-31 to answer the second research question:

2. *Comparing the effect of climate change on the wholesale spot price between the years 2009-10 and 2030-31 with and without a carbon price.*

In subsequent sections, the methodology used to address this research question will be outlined and the results obtained from ANEM model simulations reported.

E.1 Background

The objective of this Appendix is to assess the implications of climate change on wholesale electricity prices where the main 'transmission' mechanism through which climate change operates is through its effect on electricity demand as addressed in Chapter 5.

The ANEM simulations performed for this investigation utilise projected regional demand profiles based upon the nodal demand equations presented in Sections 5.2 and 5.3. In both Section 7.1 and Appendix D, the close correspondence between the results of ANEM model simulations based on actual and projected 2009-10 demand profiles was established for performance metrics based on average spot prices and spot price volatility by State. This outcome allows us to proceed with confidence to use the ANEM model to make comparisons between the years 2009-10 and 2030-31 based on the demand projections for those years in relation to assessment of average spot prices and spot price volatility by State.

E.2 Methodology

To make comparisons to ascertain the key consequences of climate change on the NEM requires a baseline from which deviations in key variables of interest can be assessed. In this Appendix, two particular baselines will be defined and used, with the particular choice being linked to the carbon price setting adopted in model simulations.

For a carbon policy exclusive setting of $\$0/tC0_2$, the BAU setting will be the results associated with a particular benchmark year. The benchmark year adopted in this Appendix is 2009-10. Recall that Section 7.1 and Appendix D establish the close degree of correspondence between the results obtained from the actual and projected 2009-10 demand profiles. Therefore, we will not lose any information or generality by using the results from the 2009-10 projected demand profiles in place of results from the actual 2009-10 demand profiles.

The other reason to adopt the results from the 2009-10 projected demand profiles as the baseline year is to ensure logical consistency in the way climate change impacts are addressed in the modelling. In this case, consistency is achieved by using the same set of nodal demand equations to project the impact of climate change on nodal electricity demand for all of the years being considered.

For the situation where the carbon price is set to $0/tC0$_2$, the impact of climate change on average spot prices, for the period 2010-11 to 2030-31, can be examined by comparing the results in these years against the 2009-10 benchmark results based on the 2009-10 projected demand profile. In abstracting from the effects of a carbon price, this analysis most clearly focuses on the direct impact of climate change on wholesale spot prices. In the case where a carbon price of $23/tC0$_2$ is adopted in simulations, then for purposes of comparison, the nature of the baseline changes. In this case, the baseline will now be the results of ANEM model simulations undertaken using the projected demand profiles for years 2009-10 to 2030-31 but with the carbon price set to $0/tC0$_2$ – termed the carbon price exclusive $0/tC0$_2$ simulation.

Note that this baseline corresponds to the outcomes from the model simulations discussed in the previous paragraphs for the period 2010-11 to 2030-31 that were subsequently compared against the 2009-10 outcomes to assess the direct impact of climate change relative to the 2009-10 benchmark financial year. Therefore, the baseline used for comparison purposes for simulations containing a carbon price signal extends over the years 2009-10 to 2030-31 and already contains the impact of climate change as determined from the carbon policy exclusive (e.g. $0/tC0$_2$) simulations. In this case, comparisons with the carbon policy inclusive (e.g. $23/tC0$_2$) simulations would focus directly on the impact of the carbon price itself.

E.3.1 Performance metrics used

To assess the impact of climate change on wholesale spot prices, we are concerned with ANEM simulation outcomes related to:

- average spot price levels by state;
- spot price volatility by state; and
- carbon pass-through rates by state.

We make use of growth rates defined relative to the appropriate BAU baseline in order to compare the consequences of climate change or carbon price effects from model simulations. The per cent change calculations are calculated using the formula: %Change = [(projected_val – bau_val)/bau_val]*100.

For simulation involving no carbon price, the variables 'projected_val' represents an output metric defined over the period 2010-11 to 2030-31 while 'bau_val' denotes the same output metric defined from the baseline $0/tC0$_2$ 2009-10 model simulation.

In relation to simulations containing a carbon price signal, then the variable 'projected_val' represents an output metric defined year-on-year over the period 2009-10 to 2030-31 associated with carbon price inclusive ($23/tC0$_2$) simulations, while the 'bau_val' denotes the same output measure defined for the same year from the carbon price exclusive ($0/tC0$_2$) baseline simulation.

E.3.2 Calculation of performance metrics

The average price results reflect a spatial and temporal dimension. For each hourly dispatch interval in a given year, an average State spot price level was obtained by averaging across all relevant nodal prices within each State as indicated by the nodal structure contained in each State module outlined in Appendix B. The average annual price for each State was then obtained by averaging across the number of hours in each respective year. The average annual price for the NEM was calculated by averaging across the five state average annual price levels.

The price volatility measure was calculated by taking the standard deviation of the spot price time series generated by the ANEM model for each node and then averaging these results across the nodes located within each State to calculate spot price volatility by State. We then average across states to obtain the NEM results.

Carbon pass-through can be defined as the incidence of the carbon tax or tradable carbon permit and refers to the proportion of carbon prices (expressed in $/tC02) that are passed through into wholesale electricity spot prices (expressed in $/MWh) (Nelson, Orton & Kelley 2010).

The rate of carbon pass-through is calculated in a two-step process. First, the price differential between average annual prices associated with a carbon price inclusive and the baseline carbon price exclusive scenario is calculated. This price differential is then divided by the carbon price level itself. If the resulting proportion is less than unity, then there is less than complete pass-through of the carbon price into average annual prices. If the proportion equals unity, then there is complete pass-through. The difference between the price levels is exactly equal to the carbon price level. If the proportion is greater than unity, there is more than complete pass-through. In this case, the carbon price would have a 'magnified' effect on average annual prices.

E.4 Results

The results associated with the output metrics mentioned above are presented in the next two sections. The first set of results will detail outcomes from simulations in which the carbon price was set to $0/tC02 (i.e. no carbon price signal). The second set of results reported in the following section will relate to simulations in which the carbon price was set to $23/tC02.

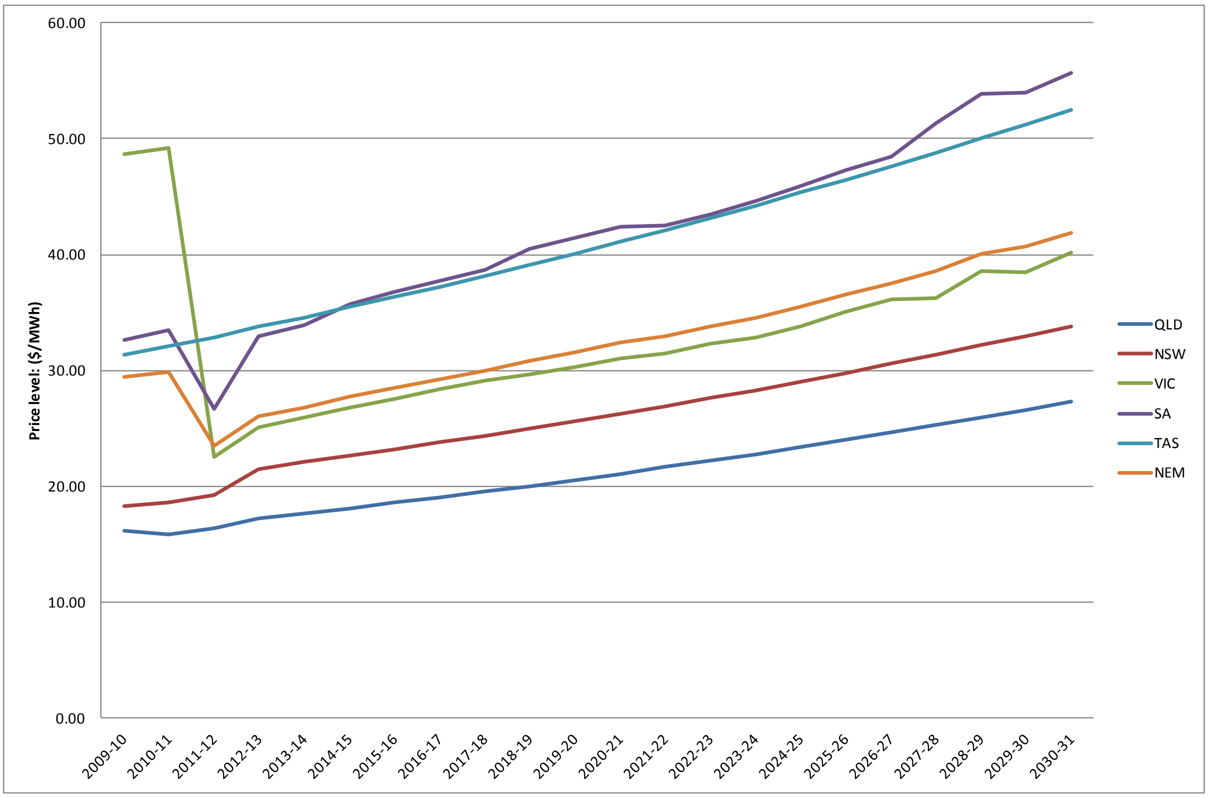
E.4.1 Impact of climate change on wholesale spot prices for the period 2009-10 to 2030-31 without a carbon price

The first set of results are reported in Figure E-1 and relates to plots of average wholesale spot price levels by State for the period 2009-10 to 2030-31. The most noticeable feature is the extent to which the average spot price level in Victoria exceeds the other States over the period 2009-10 to 2010-11, followed by a significant drop in 2011-12, bringing it back in line with other mainland States. The same behaviour occurs to a less degree for South Australia over the same period as well.

The other noticeable feature is that both Tasmania and South Australia experience higher average price levels over the period of investigation when compared to the other mainland States after the correction to average prices in Victoria in 2011-12. This result for Tasmania can be attributed to the fact that supply offers of Tasmanian hydro plant are based on long run marginal costs. The resultant marginal cost is higher than equivalent cost structures for thermal plant on the mainland.

In the case of South Australia, the higher average price levels reflect the greater prominence of gas generation in that state when compared with other States. Therefore, it is more likely in South Australia, that a gas generator will be the 'marginal' (e.g. price setting) generator, and the subsequent cost structure is likely to exceed the cost structures of coal generation in other mainland States, and especially in the absence of a carbon price in the case of Victoria.

Figure E-1 Average spot price levels by state for 2009-10 to 2030-31 for $0/tC0$_2$



The significant movement in the average spot price in Victoria over the period 2009-10 to 2011-12 raises question marks about using 2009-10 as the baseline for analysing the impact of climate change on wholesale electricity prices for the whole period of investigation. The main reason for this is because these price movements predominantly reflect changes in the generation structure over this period of time with the commissioning of Mortlake power station in 2011-12.

The main cause of the higher average price levels in Victoria in the 2009-10 to 2010-11 time period is linked to the more intensive dispatch of more expensive hydro units located in both the Murray and Dederang nodes when compared to the dispatch patterns of these hydro units prevailing after 2010-11. This reduction in dispatch of the hydro units in 2011-12, in turn, is linked to the commissioning of Mortlake power station.

See Appendix B for further details on the location of the hydro plant and Mortlake power station.

These trends can be seen in Table E-1 which reports annual capacity factor for selected generation plant. The annual capacity factor values in Table E-1 were calculated by summing the number of hours in each year that each individual hydro (and gas) turbine was dispatched, then dividing this by the total number of hours in the year. For the hydro plants listed in Panels (A) to (D) of Table E-1, there is a noticeable drop in the annual capacity factor for 2011-12 when compared to the equivalent values recorded in the 2009-10 to 2010-11 period. This is highlighted in yellow shading in Table E-1. This corresponds, at the same time, with the commissioning of Mortlake which became operational in 2011-12 as indicated by the jump in its annual capacity factor in Panel (E) of Table E-1 (also shaded in yellow).

Recall from the discussion in Section C.4 of Appendix C that the marginal cost (and supply offer) of successive hydro turbines in a hydro plant such as turbines 1 to 10 of Murray 1 escalate in magnitude. For example, the cost of supply for Murray 1 unit 10 (e.g. 'Mur1_10' in Table E-1) and McKay Creek unit 6 (e.g. 'McK 6') would be much more expensive than the cost of supply of Murray 1 unit 1 (e.g. 'Mur1_1'), McKay Creek unit 1 (e.g. 'McK 1') and Mortlake power station from 2011-12 as well. It is this escalation in the cost of supply of successive hydro units (e.g. turbines) that is responsible for the successive decline in annual capacity factor recorded for successive turbines listed in Panels (A) to (D) of Table E-1 for the hydro plants listed in that table.

Table E-1 Annual capacity factors for Victorian hydro generation plant and Mortlake power station

Panel (A) Murray 1

Year	Mur1_1	Mur1_2	Mur1_3	Mur1_4	Mur1_5	Mur1_6	Mur1_7	Mur1_8
2009-10	0.0179	0.0131	0.0112	0.0091	0.0085	0.0072	0.0018	0.0003
2010-11	0.0181	0.0131	0.0112	0.0091	0.0085	0.0072	0.0018	0.0003
2011-12	0.0109	0.0058	0.0048	0.0038	0.0030	0.0022	0.0003	0.0003

Panel (B) Murray 1, Murray 2 and Hume

Year	Mur1_9	Mur1_10	Mur2_1	Mur2_2	Mur2_3	Mur2_4	Hum 1	Hum 2
2009-10	0.0003	0.0003	0.0141	0.0107	0.0072	0.0015	0.0096	0.0065
2010-11	0.0003	0.0003	0.0142	0.0107	0.0072	0.0015	0.0096	0.0065
2011-12	0.0003	0.0003	0.0071	0.0046	0.0018	0.0003	0.0040	0.0014

Panel (C) Dartmouth, McKay Creek and Bogong

Year	Dart	McK 1	McK 2	McK 3	McK 4	McK5	McK 6	Bong 1
2009-10	0.0154	0.0200	0.0099	0.0074	0.0065	0.0065	0.0065	0.0178
2010-11	0.0154	0.0200	0.0099	0.0074	0.0065	0.0065	0.0065	0.0178
2011-12	0.0077	0.0097	0.0042	0.0015	0.0014	0.0014	0.0014	0.0085

Panel (D) Bogong, West Kiewa, Clover and Eildon

Year	Bong 2	W Kie 1	W Kie 2	Clov 1	Clov 2	Eld 1	Eld 2
2009-10	0.0079	0.0221	0.0094	0.0097	0.0077	0.0169	0.0073
2010-11	0.0079	0.0221	0.0094	0.0097	0.0077	0.0169	0.0073
2011-12	0.0016	0.0109	0.0019	0.0033	0.0016	0.0080	0.0015

Panel (E) Mortlake

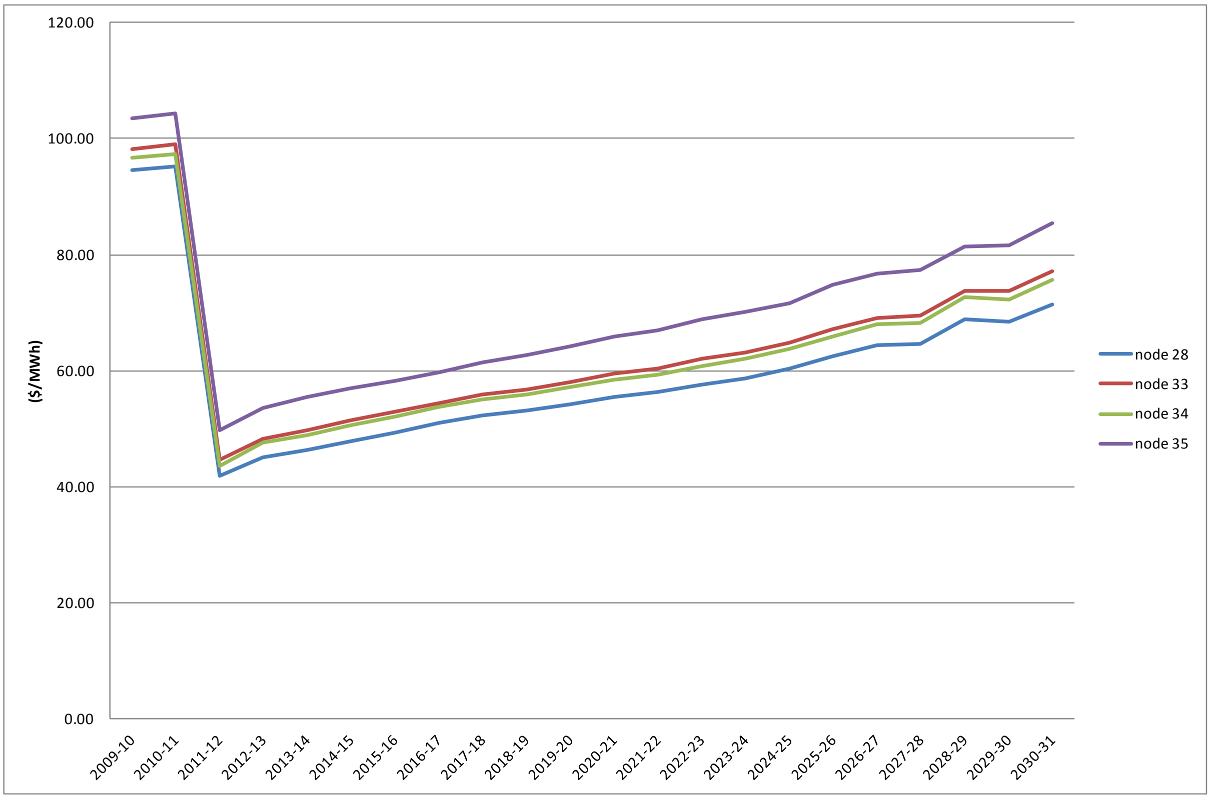
Year	Mort 1	Mort 2
2009-10	0.0000	0.0000
2010-11	0.0000	0.0000
2011-12	0.0240	0.0240

There are three reasons for the trends observed in Table E-1. First, Mortlake power station has a cost structure that is typically shadowed by only the first unit (e.g. turbine) in the hydro generation plant. Second, Mortlake power station has a significant capacity of 566MW and is well placed to displace more costly capacity sourced from hydro plant located in the Murray and Dederang nodes. Third, Mortlake power station is located in the South West Victorian node which shares in common with the Dederang node, direct transmission connections to the greater Melbourne/Geelong area and an indirect connection (via Melbourne) to regional Victoria (see Appendix B for details). Therefore, Mortlake power station is well placed to successfully compete with more costly hydro units located in the Murray and Dederang nodes as a peak load supplier of electricity to both the Greater Melbourne and regional Victorian regions.

These considerations together suggest that the Dederang (node 28), Greater Melbourne (node 33), South West Victorian (node 34) and regional Victorian (node 35) are likely to share the same marginal (e.g. price setting) generator, in the absence of congestion on transmission branches connecting these particular nodes. Strong evidence supporting this view can be observed in Figure E-2 which shows a close correspondence in qualitative terms between the time paths of the average nodal spot price levels obtained for these four Victorian nodes for the period 2009-10 to 2030-31. Moreover, these price trends also partially leak into the Murray and South East South Australian nodes which are connected to the Dederang and South West Victorian nodes, respectively (see Appendix B). In fact, it is this leakage from the South West Victorian node to the South East South Australian node that is responsible for driving the South Australian spot price outcomes observed in Figure E-1 over the period 2009-10 to 2011-12.

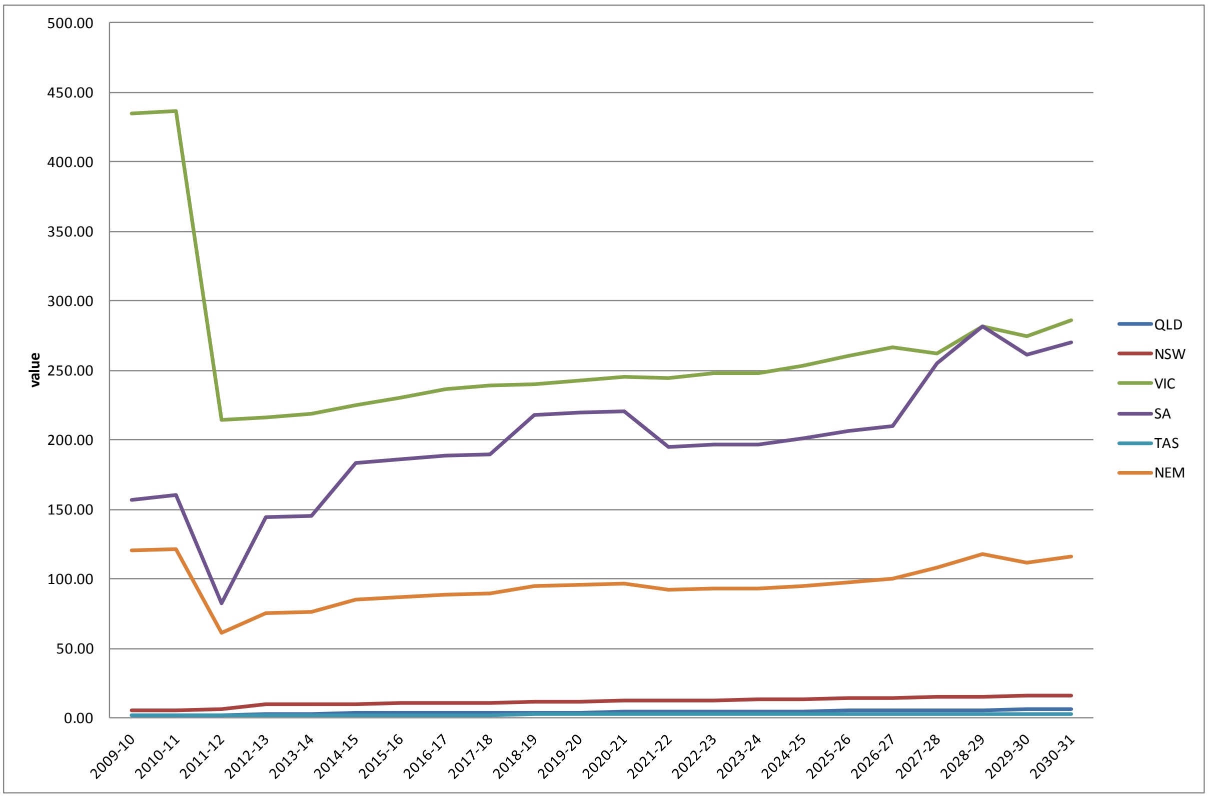
It is also acknowledged that the average spot price trends observed for Victoria for the period 2009-10 to 2011-12 also reflect the particular assumptions made about the cost structures of hydro generation plant in the ANEM model and particularly about the escalation of cost structures across successive turbines. Changes in the assumption or escalation rate details could remove or ameliorate the magnitude of the average price movements observed in Figures E-1 and E-2.

Figure E-2 Average nodal price levels of Victorian nodes 28, 33, 34 and 35 for 2009-10 to 2030-31 for $0/tC0$_2$



The spot price volatility results obtained from the model simulations are shown in Figure E-3. Once again, a big movement in spot price volatility by State occur over the 2009-10 to 2011-12 time interval and match, in qualitative terms, the average price trends identified in Figure E-1 especially in the case of Victoria and South Australia. After 2011-12, price volatility becomes more stable although Victoria and South Australia still continue to experience a greater quantum of spot price volatility when compared to the other states.

Figure E-3 Annual spot price volatility for 2009-10 to 2030-31 for $0/tC$0_2$



The average spot price levels (in $/MWh) and percentage growth in average spot prices relative to the 2009-10 ($0/tC$0_2$) benchmark year by State are presented in Panels (A) and (B) of Table E-2, for the whole period 2009-10 to 2030-31.

Table E-2 Average spot price levels and percentage growth by state relative to 2009-10 ($0/tC$0_2$) outcomes

Panel (A) Wholesale price levels

Year	QLD	NSW	VIC	SA	TAS	NEM
2009-10	16.20	18.28	48.69	32.67	31.31	29.43
2010-11	15.87	18.66	49.16	33.47	32.09	29.85
2011-12	16.34	19.20	22.59	26.72	32.89	23.55
2012-13	17.21	21.50	25.08	32.96	33.75	26.10
2013-14	17.65	22.07	25.90	33.87	34.60	26.82
2014-15	18.10	22.63	26.75	35.75	35.46	27.74
2015-16	18.57	23.20	27.53	36.73	36.34	28.47
2016-17	19.05	23.77	28.38	37.72	37.25	29.23
2017-18	19.54	24.37	29.11	38.70	38.17	29.98
2018-19	20.04	24.99	29.65	40.54	39.13	30.87
2019-20	20.56	25.62	30.33	41.48	40.10	31.62
2020-21	21.09	26.26	31.06	42.46	41.10	32.39
2021-22	21.64	26.92	31.50	42.47	42.12	32.93
2022-23	22.21	27.60	32.35	43.49	43.17	33.77
2023-24	22.78	28.31	32.89	44.60	44.24	34.57
2024-25	23.38	29.05	33.80	45.87	45.34	35.49

Year	QLD	NSW	VIC	SA	TAS	NEM
2025-26	24.00	29.80	35.06	47.25	46.47	36.52
2026-27	24.64	30.57	36.11	48.50	47.62	37.49
2027-28	25.27	31.33	36.29	51.28	48.81	38.60
2028-29	25.95	32.16	38.54	53.92	50.02	40.12
2029-30	26.63	32.97	38.45	54.02	51.26	40.67
2030-31	27.33	33.83	40.22	55.70	52.54	41.92

Panel (B) Percentage change in wholesale price from 2009-10 (\$0/tCO_2) BAU levels

Year	QLD	NSW	VIC	SA	TAS	NEM
2010-11	-2.07	2.09	0.97	2.43	2.50	1.19
2011-12	0.86	5.07	-53.60	-18.21	5.06	-12.16
2012-13	6.20	17.63	-48.48	0.89	7.82	-3.19
2013-14	8.92	20.78	-46.80	3.66	10.51	-0.58
2014-15	11.70	23.82	-45.07	9.43	13.27	2.63
2015-16	14.60	26.92	-43.46	12.43	16.09	5.32
2016-17	17.59	30.08	-41.70	15.44	18.97	8.08
2017-18	20.58	33.34	-40.21	18.46	21.94	10.82
2018-19	23.69	36.73	-39.10	24.07	24.97	14.07
2019-20	26.90	40.20	-37.70	26.95	28.09	16.89
2020-21	30.16	43.69	-36.21	29.95	31.28	19.77
2021-22	33.57	47.32	-35.30	29.98	34.54	22.02
2022-23	37.06	51.03	-33.55	33.12	37.89	25.11
2023-24	40.60	54.91	-32.44	36.53	41.31	28.18
2024-25	44.30	58.94	-30.57	40.39	44.83	31.58
2025-26	48.13	63.04	-27.99	44.61	48.43	35.24
2026-27	52.04	67.29	-25.84	48.46	52.12	38.82
2027-28	55.97	71.45	-25.47	56.96	55.90	42.96
2028-29	60.12	75.95	-20.83	65.05	59.76	48.01
2029-30	64.34	80.42	-21.02	65.34	63.74	50.56
2030-31	68.67	85.12	-17.39	70.48	67.81	54.94

The data in Panel (A) of Table E-2 is the same data plotted in Figure E-1. It is clear from this panel that the wholesale Victorian spot price drops from \$49.16/MWh in 2010-11 to \$22.59/MWh and all States experience unambiguous growth in average spot prices from 2012-13 to 2030-31 as borne out in Panel (B) of Table E-2. The complication that arises is in interpreting this growth relative to the 2009-10 (\$0/tCO_2) BAU levels when the average wholesale price level for Victoria in 2030-31 is less than the corresponding value in 2009-10. Hence, the positive growth experienced in Victorian average spot prices over the period 2012-13 to 2030-31 in Panel (A) shows up as negative percentage growth when defined relative to the ‘high’ 2009-10 benchmark average spot price level. For example, in 2030-31, the average spot price is 17.4 per cent lower than the 2009-10 BAU level and the percentage growth relative to BAU clearly declines, however, at a diminishing rate as indicated in Panel (B). However, when judged against the 2013-14 average price level, for example, the 2030-31 Victorian average spot price level is 55.3 per cent above the 2013-14 average spot price level.

For the other States, the results look more reasonable, with 2030-31 average spot prices for Queensland, New South Wales, South Australia and Tasmania being 68.7 per cent, 85.1 per cent, 70.5 per cent and 67.8 per cent higher than the corresponding 2009-10 levels, respectively. For the NEM, the percentage increases by State translate into a 54.9 per cent increase. It is also noticeable from the results listed in Panel (B) that both Queensland and Tasmania experience the lowest percentage growth rates in average spot prices relative to 2009-10 benchmark levels for the period 2010-11 to 2030-31. This result is consistent with our *a priori* expectations because in Section 3.2.2, it was demonstrated that the CSIRO-Mk3.5 GCM tends to downplay the impact of climate change on temperature in both Queensland and Tasmania when compared to the other States.

E.4.2 Impact of climate change on wholesale spot prices for the period 2009-10 to 2030-31 in the presence of a carbon price of $23/tC0$_2$

In this section, we assess the impact of a carbon price of $23/tC0$_2$ on average spot prices determined from ANEM model simulations. We examine this aspect from two particular perspectives. The first relates to the impact arising in 2009-10 and will be performed by calculating the percentage change in average spot prices associated with the carbon price against the levels calculated from the 2009-10 ($0/tC0$_2$) benchmark used in the previous section. We also examine the link between the carbon price and average spot prices through analysis of carbon pass-through rates.

In a following section, we examine the consequences of the carbon price when compared against a benchmark simulation conducted over the whole 2009-10 to 2030-31 time period which accounts for the impact of climate change on projected demand but in a policy environment containing no carbon price signal. This benchmark scenario corresponds to the model simulation results associated with the carbon price exclusive ($0/tC0$_2$) scenario underpinning analysis in the previous section.

E.4.2.1 Carbon price impact in 2009-10

Details relating to average spot price levels obtained in 2009-10 from simulations containing a $23/tC0$_2$ carbon price are outlined in Table E-3. Information in this table includes average spot prices by State from simulations with and without a carbon price together with the percentage change calculation and carbon pass-through rates.

Table E-3 2009-10 average spot price levels and percentage change by state following introduction of a carbon price of $23/tC0$_2$

Carbon Price	QLD	NSW	VIC	SA	TAS	NEM
$0/tC0$_2$	16.20	18.28	48.69	32.67	31.31	29.43
$23/tC0$_2$	37.48	39.32	74.79	52.96	36.91	48.29
%Change	131.33	115.15	53.60	62.12	17.89	64.10
Carbon pass-through rate	0.9252	0.9150	1.1347	0.8823	0.2434	0.8201

In Table E-3, the average price results by state associated with the 2009-10 ($0/tC0$_2$) results are listed in the 'BAU' row. The average spot price levels associated with the carbon price inclusive ($23/tC0$_2$) simulation using the 2009-10 projected demand profiles is reported in row '$23' in Table E-3. The percentage change calculation is reported in the third row of Table E-3 and is calculated using the %Change formula outlined in Section E.3. In this formula, 'projected_val' corresponds to values in the '$23' row while 'BAU_val' relates to values in the 'BAU' row of Table E-3.

It follows from Table E-3 that those States with the higher ($0/t$C0_2$) average spot price levels experience the smaller rates of percentage increase associated with the carbon price. This relates to Victoria and South Australia. In contrast, those States with the lower average price levels experience the greater rate of increase in prices. The main reason for these outcomes is that the denominator in the %Change calculation is larger for those States with higher benchmark ($0/t$C0_2$) prices, thus reducing the value determined from the %Change calculation. So in this particular context, the use of the percentage change measure does not necessarily provide a good indicator of how a carbon price affects spot price levels particularly on a State by state basis.

Also note from Table E-3 that in the case of Tasmania, the gap between the average spot prices is quite narrow. This reflects the fact that a carbon price would not lift prices in Tasmania too much because the predominantly hydro based generation fleet in Tasmania is not affected by carbon costs.

In order to assess the impact of a carbon price on average spot prices across different States, a better measure is the concept of carbon pass-through. Recall that the rate of carbon pass-through is determined by calculating the price differential between average annual prices associated with a carbon price inclusive ($23/t$C0_2$) and the benchmark carbon price exclusive ($0/t$C0_2$) scenarios. This price differential is then divided by the carbon price level itself (e.g. 23 in the current case).

The importance of the concept of carbon pass-through relates to the fact that significant levels of carbon pass-through indicate that consumers are bearing a large proportion of the carbon price/tax while a low rate would indicate that producers (e.g. generators) are bearing a high proportion of the incidence of the carbon price/tax (Nelson, Orton & Kelley 2010).

The carbon pass-through rates calculated for the 2009-10 average price outcomes by State are listed in the 'carb' row of Table E-3. The carbon pass-through rate for Tasmania is significantly lower than other States reflecting the prominence of hydro generation in this State which does not face a carbon footprint or variable carbon cost impost. Similarly, the carbon pass-through rate for Victoria is both greater than unity and greater than the pass through rates of the other States. This reflects the prominence of brown coal fired generation in that state which has particularly high carbon footprint and susceptibility to variable carbon costs. The pass-through rates for Queensland and New South Wales are of similar magnitude reflecting the similarity in each State's particular dependence upon black coal generation and NGCC plant. South Australia's carbon pass-through rate is of a lower magnitude when compared to the other mainland States and reflects the greater prominence of gas generation in that State when compared to the other mainland States. Gas generation has a smaller carbon footprint than coal generation and therefore is less susceptible to variable carbon cost imposts.

Note that the contribution of solar PV and non-scheduled wind generation would ordinarily be expected to further reduce the rates of carbon pass-through in South Australia and Victoria, in particular. However, these components have already been netted off from the demand concept underpinning the nodal demand projections which is a net demand concept instead of a gross demand concept.

E.4.2.2 Carbon price impact over the period 2009-10 to 2030-31

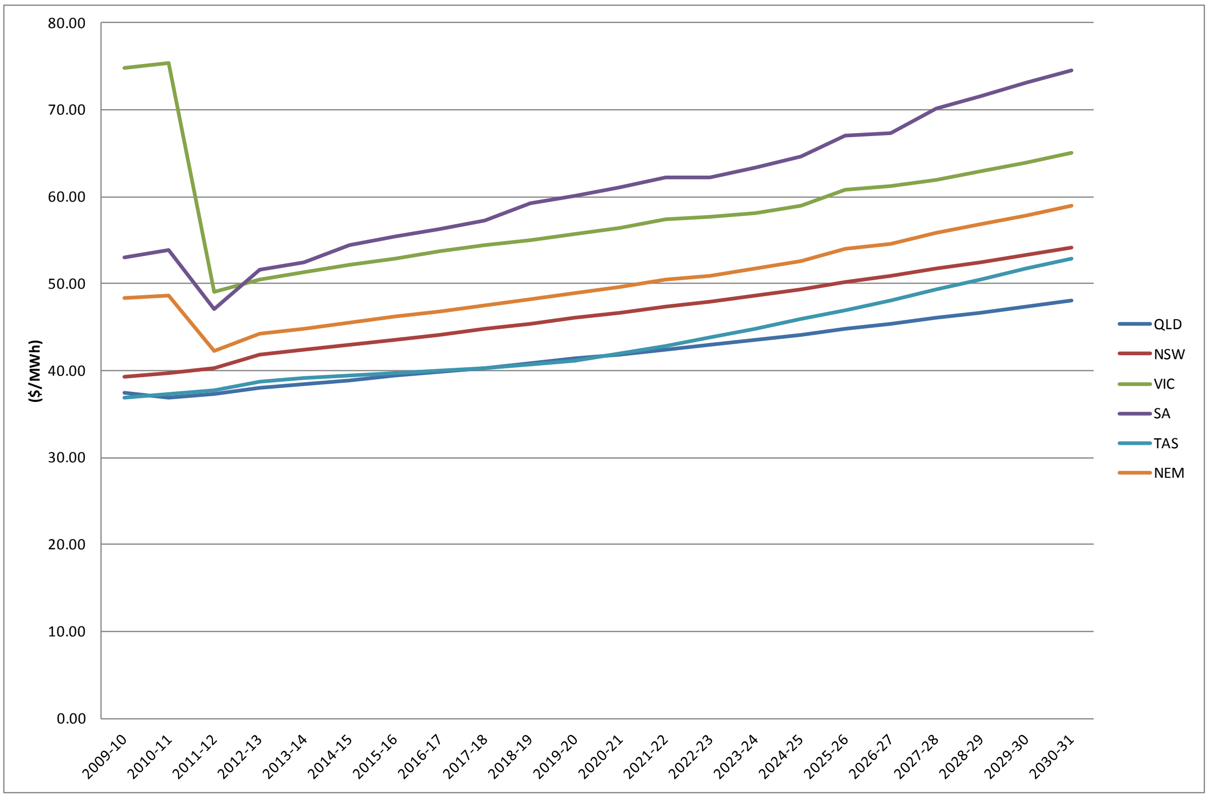
In this section, we examine the consequences of the carbon price when compared against a benchmark ($0/tC$0_2$) simulation conducted over the whole 2009-2010 to 2030-31 time period which accounts for the impact of climate change on projected demand but in a policy environment containing no carbon price signal.

The key metric used in this section is a percentage rate of change conducted on a year-on-year basis over the period 2009-10 to 2030-31 constructed as: % Change = [($23/tC$0_2$ - $0/tC$0_2$)/$0/tC0_2]*100. Note that '$23/tC$0_2$' is the average spot price level by State from the carbon price inclusive $23/tC$0_2$ simulation and '$0/tC$0_2$' is the equivalent average spot price level from the carbon price exclusive $0/tC$0_2$ simulation. According to the above formula, the percentage rate of change would diminish if the average spot price level from the $0/tC$0_2$ simulation increased relative to that associated with the $23/tC$0_2$ simulation by both reducing the numerator and increasing the denominator in the percentage rate of change calculation.

Another important aspect to note with this metric is that the year-on-year application ensures we are comparing 'apples with apples'. For example, the results are not affected by variation in generation structures associated with commissioning and decommissioning of a generation plant over time or variations in demand over time. In effect, the generation structure and demand structure is fixed on the year-on-year comparisons and the only key variation between simulations will be in the carbon price.

The first set of results are shown in Figure E-4 and relates to plots of average wholesale spot price levels by state for the period 2009-10 to 2030-31 from the carbon price inclusive ($23/tC$0_2$) simulations. The most noticeable feature in this figure is its general similarity in qualitative terms to the results documented in Figure E-1 in Section E.4.1. Once again note that the average spot price level in Victoria exceeds that of the other States over the period 2009-10 to 2010-11, followed by a significant drop in 2011-12, bringing it back broadly in line with other mainland States. However, there are a few noticeable differences between the two figures in relation to relative positions of States. In Figure E-1, Tasmania has one of the highest average spot price paths whereas in Figure E-4, it now has one of the lowest, reflecting the low carbon footprint of its generation fleet which is predominantly based around hydro generation. Instead, in Figure E-4, Victoria now has one of the highest average spot price paths, reflecting the higher carbon footprint of its predominately brown coal generation fleet in the presence of the carbon price signal. In particular, Victoria's upward shift in Figure E-4, in relative terms, compared to the positions that Queensland and New South Wales hold in Figure E-4 and all hold in Figure E-1 points to the deterioration in its competitive position of Victoria relative to New South Wales and Queensland following the imposition of the carbon price.

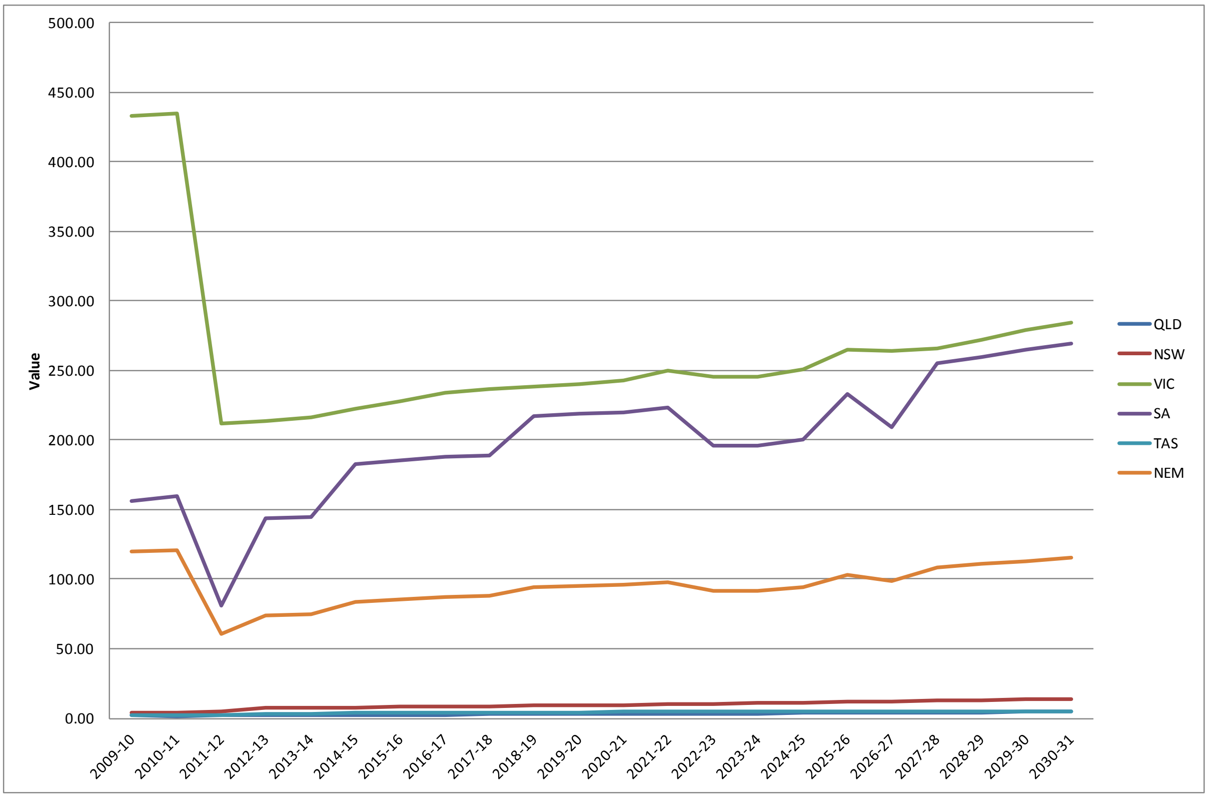
Figure E-4 Average spot price levels by state for 2009-10 to 2030-31 for $23/tC$0_2$



Spot price volatility results are outlined in Figure E-5. The most noticeable feature in this figure again is its similarity in qualitative terms to the results documented in Figure E-3 in Section E.4.1. More generally, the big movement in spot price volatility continue to occur over 2009-10 to 2011-12 and broadly match the patterns outlined in Figure E-4. After 2011-12, spot price volatility becomes more stable although Victoria and South Australia still continue to experience greater amounts of volatility when compared to the other States. Moreover, the pattern of volatility experienced by South Australia differs in observable ways from the path outlined in Figure E-3.

The similarity in the results reported in Figures E-4 and E-5 when compared to Figures E-1 and E-3 in Section E.4.1, indicate that the same factors identified in that section as determining average price trends continue to operate in the current environment containing the carbon price of $23/tC$0_2$. This relates particularly to the nature of dispatch and cost escalation of the hydro generation units located in the Murray and Dederang nodes and the role of Mortlake power station over the period 2009-10 to 2011-12.

Figure E-5 Annual spot price volatility by state for 2009-10 to 2030-31 for \$23/tC0$_2$



The next set of results relate to the percentage change in average spot prices that can be attributed to the carbon price instrument itself after netting out contribution associated with climate change impacts under a policy setting of no carbon price. Recall that this is determined by subtracting the average price levels obtained from the carbon price inclusive (\$23/tC0$_2$) simulations from the average price levels obtained from carbon price exclusive (\$0/tC0$_2$) simulation, utilising in both cases, the same projected demand profiles for years 2009-10 to 2030-31.

These results are outlined in Table E-4. The most noticeable feature is that the magnitude of the percentage change between average spot prices from the carbon price inclusive and exclusive benchmark simulations decline as we move towards the end of the investigation horizon (e.g. towards 2030-31). Note that the positive percentage change results listed in Table E-4 can be interpreted as giving an indication of average spot price 'lift' associated with the carbon price signal itself over and above the lift in average spot prices implied in the benchmark (\$0/tC0$_2$) scenario that can be directly attributed to the impact of climate change. Recall that this latter impact is encapsulated in the projected demand profiles for the period 2009-10 to 2030-31 that was used in both scenarios, including the benchmark (\$0/tC0$_2$) scenario.

Table E-4 Percentage change in wholesale price from ($0/t$CO_2$) levels for 2009-10 to 2030-31

Year	QLD	NSW	VIC	SA	TAS	NEM
2009-10	131.33	115.15	53.60	62.12	17.89	64.10
2010-11	132.06	112.78	53.41	60.74	16.30	62.86
2011-12	128.26	109.44	117.38	76.08	14.77	79.56
2012-13	120.92	94.86	101.38	56.68	14.85	69.21
2013-14	117.88	92.29	98.18	54.99	13.19	66.97
2014-15	114.94	90.00	94.99	52.07	11.14	64.28
2015-16	111.99	87.79	92.18	50.68	9.13	62.14
2016-17	109.10	85.66	89.30	49.36	7.18	60.06
2017-18	106.41	83.58	87.15	48.09	5.52	58.20
2018-19	103.72	81.54	85.71	45.98	3.97	56.22
2019-20	101.08	79.54	83.84	44.97	2.45	54.54
2020-21	98.53	77.60	81.77	43.94	1.98	53.11
2021-22	95.97	75.66	82.42	46.59	1.73	53.21
2022-23	93.51	73.81	78.23	42.93	1.49	50.80
2023-24	91.15	71.93	76.76	41.89	1.29	49.55
2024-25	88.76	70.03	74.56	40.79	1.16	48.20
2025-26	86.41	68.23	73.47	42.00	1.07	47.75
2026-27	84.16	66.50	69.49	38.62	1.00	45.54
2027-28	82.06	64.95	70.56	36.74	0.93	44.56
2028-29	79.88	63.24	63.17	32.69	0.86	41.61
2029-30	77.82	61.67	66.35	35.22	0.81	42.30
2030-31	75.79	60.08	61.73	33.74	0.76	40.58

Interestingly, from Table E-4, the carbon price has more lift in the case of Queensland when compared to the results for New South Wales, Victoria and South Australia. This reflects the fact that benchmark ($0/t$CO_2$) average spot prices are higher in the three latter States than in Queensland. This result can be attributed to the climate change impacts associated with the CSIRO-Mk3.5 GCM which are more severe in New South Wales, Victoria and South Australia than in Queensland and which ratchets up demand in the three former States when compared with Queensland.

In the case of Tasmania, it is the lack of lift in average spot prices attributable to the carbon price itself that is producing the low percentage change results reported in Table E-4 for this particular State. This arises because of Tasmania's low carbon footprint associated with its predominantly hydro generation fleet which, in turn, produces a very low variable carbon cost impost and impact on average spot prices in that State attributable to the carbon price.

More generally, the fact that the percentage growth rates decline for all States as time progresses in Table E-4 also indicates that the upward impact on average spot prices associated with climate change increasingly dominates the contribution associated with the carbon price itself. The trends in Table E-4 can only emerge over time if the gap between the average spot prices associated with the carbon price inclusive ($23/t$CO_2$) scenario and benchmark carbon price exclusive ($0/t$CO_2$) scenario narrows. This will emerge if the impact of the carbon price itself diminishes over time (i.e. 'de-carbonisation' of the generation sector associated with fuel-switching effects) or if the average price level associated with climate change impacts (e.g. the benchmark ($0/tC$0_2$) scenario) increases in relative terms.

Carbon pass-through rates and percentage change in carbon pass-through rates relative to the 2009-10 carbon pass-through rate is presented in Table E-5, Panels (A) and (B). The most prominent feature of Panel (A) is the general decline in pass-through rates experienced by every State as a function of year. Declining carbon pass-through rates are indicative of the increased absorption of carbon costs by generation within each State that has a carbon cost liability. In this context, it is certainly consistent with a trend reduction over time in the amount of the carbon price that is being passed into average spot prices and ultimately onto consumers.

In Panel (B), we have expressed the percentage change in the carbon pass-through rates listed in Panel (A) relative to the carbon pass-through rates observed for 2009-10. If the magnitude of any percentage reduction in carbon pass-through relative to 2009-10 levels increases in magnitude over time, this would be indicative of the absorption of carbon costs by generators occurring at an accelerating rate as time progresses. It is evident from Panel (B) that percentage reductions rates broadly increase in magnitude as time progresses, confirming, at least anecdotally, the absorption of carbon costs at a broadly accelerating rate. This would again point to a deceleration in the extent to which the carbon price is being passed into average spot prices as time progresses in the interval 2009-10 to 2030-31.

Table E-5 Carbon pass-through outcomes: 2009-10 to 2030-31

Panel (A) Carbon pass-through rates

Year	QLD	NSW	VIC	SA	TAS	NEM
2009-10	0.9252	0.9150	1.1347	0.8823	0.2434	0.8201
2010-11	0.9111	0.9149	1.1416	0.8838	0.2275	0.8158
2011-12	0.9114	0.9137	1.1531	0.8840	0.2112	0.8147
2012-13	0.9047	0.8866	1.1056	0.8123	0.2179	0.7854
2013-14	0.9046	0.8857	1.1055	0.8098	0.1984	0.7808
2014-15	0.9046	0.8855	1.1046	0.8094	0.1718	0.7752
2015-16	0.9042	0.8854	1.1032	0.8094	0.1443	0.7693
2016-17	0.9039	0.8854	1.1020	0.8094	0.1162	0.7634
2017-18	0.9040	0.8856	1.1030	0.8092	0.0916	0.7587
2018-19	0.9039	0.8859	1.1049	0.8104	0.0675	0.7545
2019-20	0.9036	0.8861	1.1056	0.8110	0.0428	0.7498
2020-21	0.9035	0.8861	1.1042	0.8111	0.0354	0.7481
2021-22	0.9032	0.8857	1.1287	0.8603	0.0316	0.7619
2022-23	0.9030	0.8859	1.1004	0.8117	0.0280	0.7458
2023-24	0.9029	0.8854	1.0978	0.8124	0.0248	0.7447
2024-25	0.9024	0.8845	1.0959	0.8134	0.0228	0.7438
2025-26	0.9018	0.8840	1.1200	0.8628	0.0217	0.7580
2026-27	0.9015	0.8840	1.0909	0.8144	0.0206	0.7423
2027-28	0.9017	0.8848	1.1132	0.8191	0.0197	0.7477

Year	QLD	NSW	VIC	SA	TAS	NEM
2028-29	0.9011	0.8842	1.0586	0.7664	0.0188	0.7258
2029-30	0.9010	0.8841	1.1092	0.8271	0.0180	0.7479
2030-31	0.9007	0.8837	1.0795	0.8171	0.0175	0.7397

Panel (B) Percentage change in carbon pass-through rates relative to the 2009-10 rate

Year	QLD	NSW	VIC	SA	TAS	NEM
2010-11	-1.53	-0.01	0.61	0.16	-6.56	-0.53
2011-12	-1.50	-0.14	1.62	0.19	-13.23	-0.67
2012-13	-2.22	-3.10	-2.56	-7.94	-10.50	-4.23
2013-14	-2.23	-3.20	-2.57	-8.22	-18.50	-4.79
2014-15	-2.23	-3.22	-2.65	-8.26	-29.45	-5.48
2015-16	-2.27	-3.23	-2.77	-8.27	-40.72	-6.20
2016-17	-2.31	-3.23	-2.88	-8.26	-52.27	-6.92
2017-18	-2.30	-3.21	-2.79	-8.29	-62.39	-7.50
2018-19	-2.31	-3.18	-2.63	-8.16	-72.26	-8.00
2019-20	-2.33	-3.15	-2.57	-8.09	-82.42	-8.57
2020-21	-2.35	-3.16	-2.69	-8.07	-85.44	-8.79
2021-22	-2.39	-3.20	-0.53	-2.50	-87.00	-7.10
2022-23	-2.41	-3.18	-3.02	-8.00	-88.51	-9.07
2023-24	-2.42	-3.23	-3.25	-7.93	-89.82	-9.20
2024-25	-2.47	-3.33	-3.42	-7.82	-90.63	-9.31
2025-26	-2.53	-3.39	-1.29	-2.22	-91.11	-7.57
2026-27	-2.56	-3.38	-3.86	-7.69	-91.53	-9.49
2027-28	-2.54	-3.29	-1.89	-7.17	-91.90	-8.83
2028-29	-2.60	-3.36	-6.71	-13.14	-92.29	-11.50
2029-30	-2.62	-3.37	-2.24	-6.26	-92.62	-8.81
2030-31	-2.65	-3.42	-4.87	-7.39	-92.83	-9.81

F ENERGY GENERATED BY TYPE OF GENERATOR

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This Appendix outlines the methodology and detailed results from ANEM model simulations based on the projected regional demand profiles for years 2009-10 to 2030-31 to answer the third research question:

3. *Comparing the effect of climate change on the energy generated by type of generator between the years 2009-10 and 2030-31 with and without a carbon price.*

In subsequent sections, the methodology employed to address this research question will be outlined and results obtained from ANEM market simulations reported.

F.1 Methodology

The objective of this Appendix is to assess the implications of climate change on generation production trends by state and fuel type where the main 'transmission' mechanism through which climate change operates is through its effect on electricity demand as addressed in Chapter 5.

The ANEM model simulations performed for this investigation utilise projected regional demand profiles based upon the nodal demand equations presented in Sections 5.2 and 5.3. In Section 7.1 and Appendix D, the close correspondence between the results of ANEM model simulations based on actual and projected 2009-10 demand profiles was established for energy generated by state and type of generation. This outcome allows us to proceed with confidence to use the ANEM model to make comparisons between the years 2009-10 and 2030-31 based on the demand projections for those years for energy generated by state and type of generator.

Section E.2 discusses the general methodology employed to ascertain the key consequences of climate change on the NEM which requires a baseline from which deviations in key variables of interest can be assessed. In this Appendix, we adopt the same methodological approach that was outlined in Section E.2 in regard to the choice of BAU baselines and carbon price settings.

To assess the impact of climate change on generation production trends by state and fuel type, we will be concerned with ANEM simulation outcomes related to:

- production intensity rate by state for:
    - all generation;
    - coal-fired generation;
    - gas-fired generation;
    - OCGT generation; and
    - hydro generation.

Note that OCGT generation is included to enable assessment of the impact of climate change on the key generation technology that together with hydro generation is used to meet peak load production duties.

In calculating growth rate measures, we use the same formula that was outlined in Section E.3 taking into account how its application might change with BAU baseline as explained in Section E.3.

To calculate production intensity rates, we calculate the average (MW) level of dispatch for each generator during the year and divide this value by the maximum thermal MW rating of each generator to express the average production level as a proportion of installed capacity. To determine state-specific results, according to plant type, we averaged the results across the relevant categories of plant located in each state. NEM results are calculated by simple arithmetic averaging across state results.

Production intensity rates are useful for identifying how the *intensity* of dispatch of different generation technologies might evolve in response to climate change as well as changes in marginal cost relativities associated with the introduction of a carbon price signal.

F.2 Results

The results associated with the output metric defined above will be presented in the next two sections. The first set of results will detail outcomes from carbon price exclusive ($\$0/tC0_2$) simulations. The second set of results reported in the following section will relate to carbon price inclusive ($\$23/tC0_2$) simulations in which the carbon price was set to $23/tC02. In this second set of results, the results from the ($\$23/tC0_2$) simulation will be compared with the results from the ($\$0/tC0_2$) simulations over the time period 2009-10 to 2030-31. In doing this, we will net out the impact of the carbon price from impacts of climate change already encapsulated in the ($\$0/tC0_2$) simulation results.

F.2.1 Impact of climate change on generation dispatch patterns for the period 2009-10 to 2030-31 in the absence of a carbon price

The first set of results are reported in Figure F-1 and relates to production intensity rates by state for all generation obtained from the carbon price exclusive ($\$0/tC0_2$) simulations for the period 2009-10 to 2030-31. The most noticeable feature of this figure is the extent of variation in production intensity rates over the period 2009-10 to 2012-13. It is over this period that plant commissioning and de-commissioning occurred that affected the size of the gas generation fleet in Queensland and the coal generation fleets in Queensland, New South Wales, Victoria and South Australia. Note, we did not include in any of the simulations the more *temporary* plant closures associated with Tarong, Wallerawang C, Yallourn or Northern power stations which have also been recently announced.

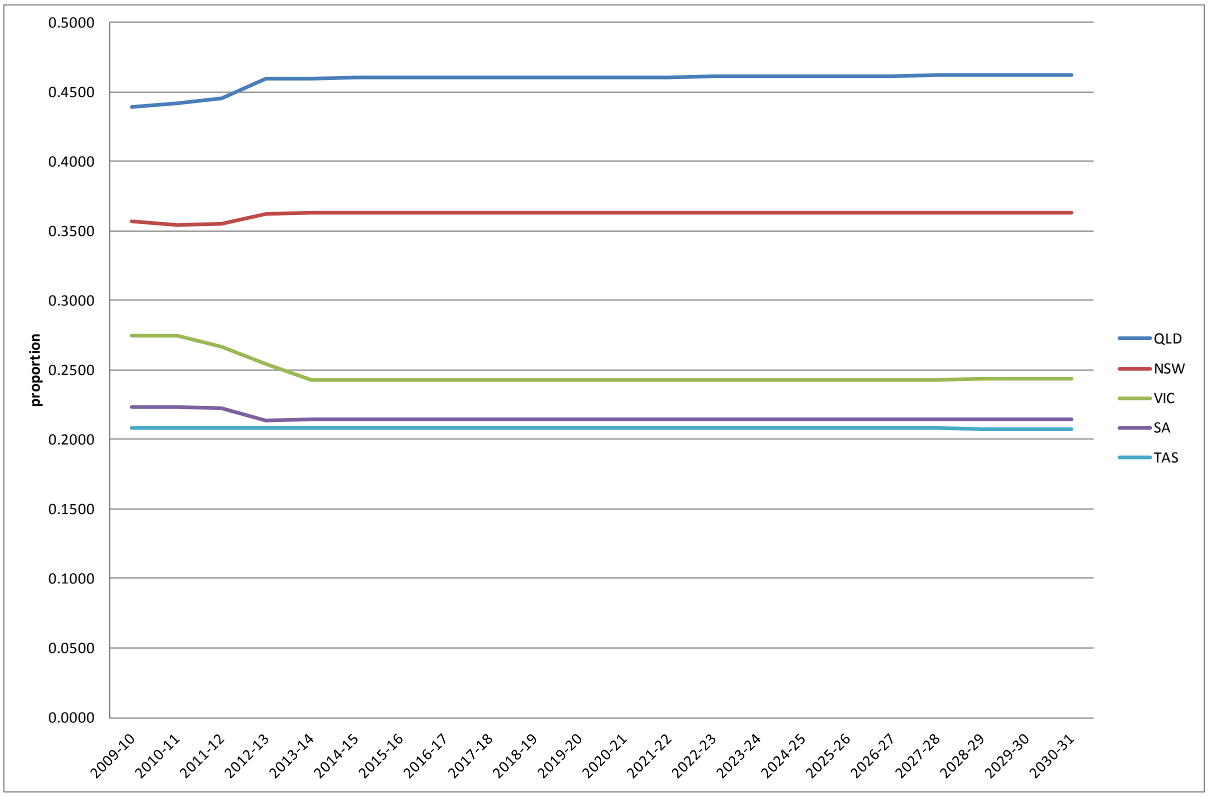
In the case of Queensland, a smooth upward trend emerges over the period 2009-10 to 2012-13. This trend is linked to the combined impact of two factors. The first is the entry of the newly commissioned Natural Gas Combined Cycle (NGCC) plant Yarwun, Darling Downs and unit 3 of Condamine power station in 2010-11. The capacity of Darling Downs, in particular, is sizeable with a rated capacity of 643 MWs. The second factor was the gradual reduction in capacity associated with the de-commissioning of Swanbank B power station over the period 2010-11 to 2012-13. In 2010-11, two units of Swanbank B with combined capacity of 250 MWs were de-commissioned. This was followed in 2011-12 with the de-commissioning of another unit with capacity of 125 MWs, followed in 2012-13 with the final unit of 125MWs. Overall, these factors produced an increase in the production intensity rate in Queensland from 0.4391 to 0.4599 over the period 2009-10 to 2012-13.

The results for New South Wales indicate a very slight increase in production intensity rate especially over the 2011-12 to 2012-13 period associated with the decommissioning of Munmorah power station in 2012-13. The production intensity rate increased from 0.3569 in 2009-10 to 0.3626 in 2012-13. This slight increase could reflect one of two possible outcomes. The first is a numeric affect that occurs when you remove data with lower values from an averaging process which would then be expected to increase the averaging result when applied to the remaining numbers. The second effect might be the more intensive dispatch of remaining units to compensate for the loss of capacity with the de-commissioning of Munmorah. This latter possibility will be examined below.

The results observed in Figure F-1 in relation to Victoria are linked to the commissioning of Mortlake power station in 2011-12 and de-commissioning of Energy Brix power station in two phases in 2012-13 and 2013-14. The commissioning of Mortlake power station had a marginal impact on the production intensity rate in Victoria because while this power station has a sizeable capacity of 566 MW, it is also a peak load gas plant. As such, it is not dispatched very much when compared to coal and gas thermal plant in that state. The observed decline in Victorian production intensity rate in Figure F-1 begins in 2011-12 with the decrease in production intensity rates of hydro units following the commissioning of Mortlake as discussed in Section E.4.1. This decline continues more noticeably over the 2012-13 to 2013-14 period with the loss of capacity associated with the de-commissioning of Energy Brix power station encompassing 141 MW in 2012-13 and a further 54 MWs in 2013-14. Overall, the production intensity rate decreases from 0.2749 in 2009-10 to 0.2664 in 2011-12, before falling to 0.2544 in 2012-13 and to 0.2430 in 2013-14.

For South Australia, there is a slight decline in 2012-13 linked to the loss of capacity associated with the de-commissioning of Playford B power station. This involves a reduction in production intensity rate for South Australia from 0.2237 in 2009-10 to 0.2138 in 2012-13. Interestingly, there is a slight increase in Tasmania, increasing from 0.2081 to 0.2087 over the 2011-12 to 2012-13 time period. This latter trend would principally be in response to the loss of capacity in Victoria with the de-commissioning of Energy Brix which would affect power exports from Victoria to Tasmania on the Basslink Interconnector. Increased production from within Tasmania would have to cover this eventuality.

Figure F-1 Production intensity rate by state for 2009-10 to 2030-31 for \$0/tC0$_2$: all generation



It was mentioned above in relation to New South Wales that it is difficult to infer whether production intensity rate changes documented in Figure F-1 over the period 2009-10 to 2013-14 reflect changes in actual dispatch of remaining units after plant de-commissioning or is a numeric effect associated with the removal of data affecting the averaging process conducted over the remaining generators.

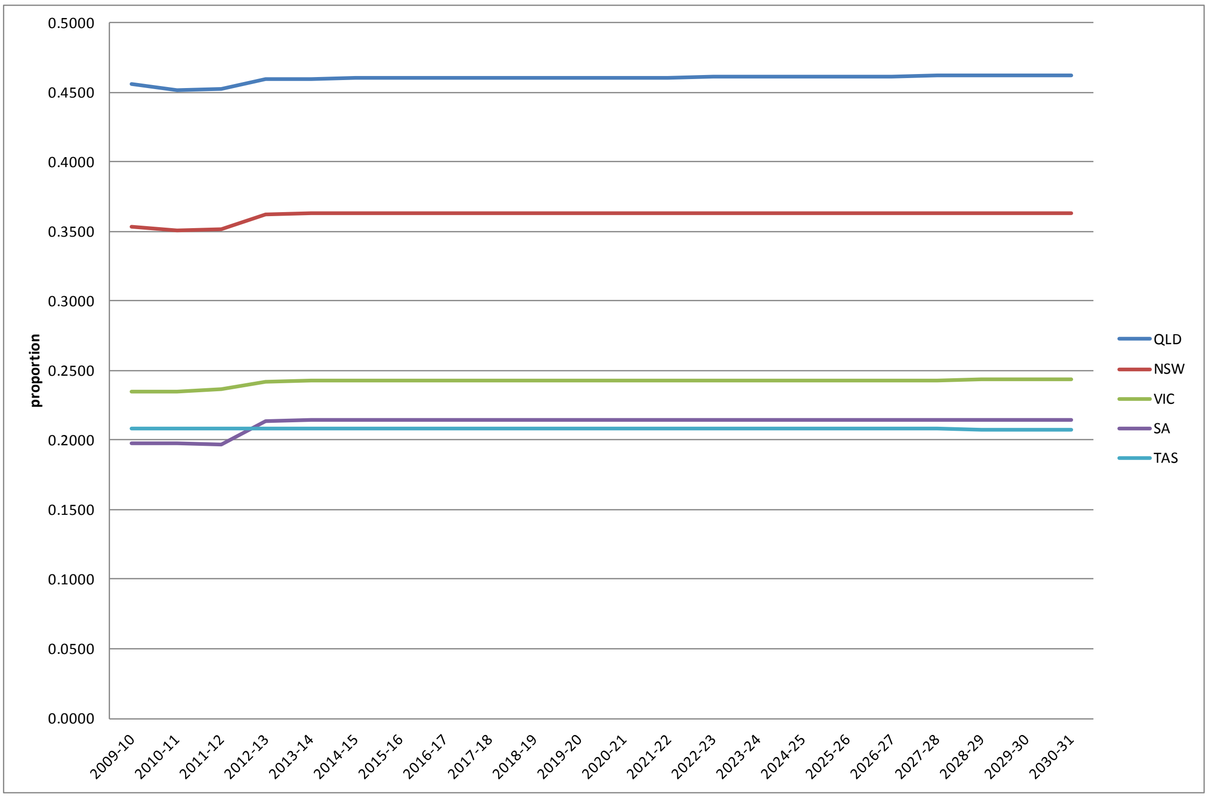
To investigate this issue, we calculated a second set of production intensity rates over the generation units excluding the plant that was de-commissioned over the period 2010-11 to 2013-14. These amended results are shown in Figure F-2. It is evident from this figure that the main affects are on the production intensity rates experienced over the period 2009-10 to 2013-14. In particular, the paths for Queensland, Victoria and South Australia are affected relative to those shown in Figure F-1 over this time period. The Queensland production intensity rate path is now pretty flat with a value of 0.4560 in 2009-10 and 0.4599 in 2012-13. Note that the effect of excluding the de-commissioned plant in the average calculation was to shift the production intensity rate upwards from 0.4391 in Figure F-1 in 2009-10 to 0.4560 in Figure F-2. Both curves match from 2012-13 onwards.

In the case of Victoria, we now observe a slight rise in the production intensity rate over the period 2009-10 to 2013-14 with the increase primarily occurring from 0.2369 in 2011-12 to 0.2422 in 2012-13 and then to 0.2430 in 2013-14. For Victoria, the effect of excluding the de-commissioned plant in the average calculation was to shift the production intensity rate downward from 0.2749 in Figure F-1 in 2009-10 to 0.2347 in Figure F-2. Both curves match from 2013-14 onwards.

For South Australia, we also observe a slight rise in the production intensity rate over the period 2009-10 to 2012-13 with the increase primarily occurring from 0.1969 in 2011-12 to 0.2138 in 2012-13. In the case of South Australia, the effect of excluding the de-commissioned plant was to shift the production intensity rate downward from 0.2237 in Figure F-1 in 2009-10 to 0.1979 in Figure F-2. Both curves match from 2012-13 onwards.

Overall, the results in Figure F-2 point to the slightly more intensive dispatch of the remaining plant in Victoria and South Australia in response to the de-commissioning of plant in 2012-13 to 2013-14. In the case of Queensland, the production intensity rates of the remaining plant remain fairly flat. For 2010-11 to 2011-12, there is actually a slight dip which would reflect the fact that the newly commissioned NGCC plant in 2010-11 has provided enough additional capacity to compensate for the loss of the Swanbank B units without other plant having to ramp up their production levels to compensate for the loss of capacity associated with the de-commissioning of Swanbank B. The other noticeable result is that from 2012-13 onwards for states other than Victoria (2013-14), the paths in Figures F-1 and F-2 coincide.

Figure F-2 Amended production intensity rate by state for 2009-10 to 2030-31 for $0/tC0$_2$: all generation



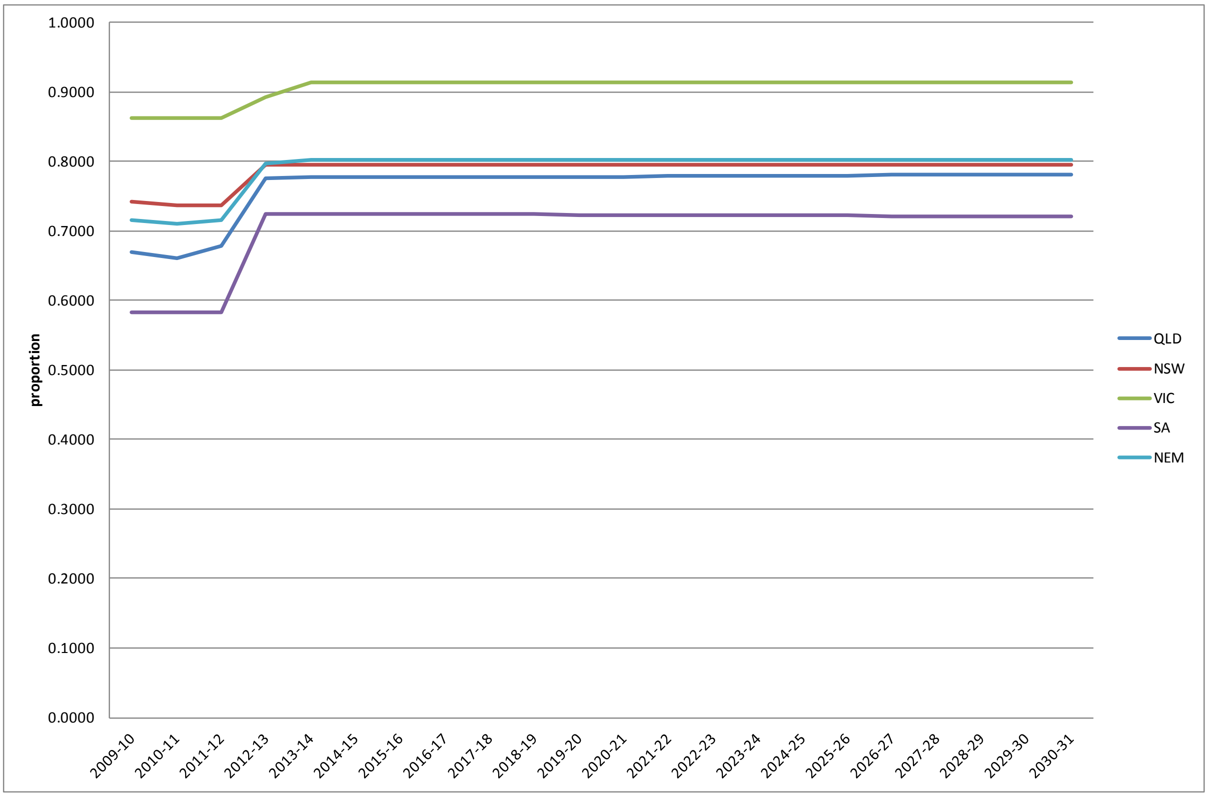
It is apparent from Figures F-1 and F-2 that Queensland and New South Wales have the highest production intensity rates which reflect their higher dependence on plant with must run configurations including black coal and NGCC plant and less reliance, in relative terms, on OCGT and hydro generation. The converse is the case for Victoria, South Australia and Tasmania. While Victoria has a significant component of must run brown coal plant, it also has a much higher proportion of peak load plant including hydro and OCGT peak plant. Because these latter types of plant only run for short times during the year, their very low production intensity rates drag down the Victorian rate relative to Queensland and New South Wales. The situation arising for South Australia reflects the much higher proportion of gas plant in that state, including a significant proportion of peak load plant. In the case of Tasmania, its generation fleet is predominantly hydro generation and much of this is aligned to intermediate or peak load duties. A significant proportion of its gas fleet is also designed to meet peak load production. Therefore, a significant proportion of Tasmania's generation fleet operates infrequently throughout the year dragging down Tasmania's production intensity rate relative to Queensland and New South Wales, in particular.

It is also evident from Figures F-1 and F-2 that the impact of climate change on all generation production intensity rates by state seems quite benign over the period 2013-14 to 2030-31. This is most clearly demonstrated by the flat slopes of the plotted production intensity rates for each state in Figures F-1 and F-2 over this period. In fact, there is a tendency for the production intensity rates to increase slightly over this period but at a rate of increase that is so small as to be not be readily distinguishable in these figures. To quantity these trends by state, the production intensity rate for Queensland increased from 0.4600 in 2013-14 to 0.4625 in 2030-31, a percentage change rate of half a per cent. For the other states the equivalent values were 0.3629 to 0.3631 in New South Wales, 0.2430 to 0.2435 in Victoria, 0.2141 to 0.2146 for South Australia and with a reduction being recorded for Tasmania going from 0.2087 to 0.2077 over the same period. In percentage changes terms, this amounted to increases of 0.06, 0.19 and 0.21 of one per cent for New South Wales, Victoria and South Australia, respectively. For Tasmania, it amounted to a half a per cent reduction in percentage change terms.

We now investigate the production intensity rate by state and fuel type to see how climate change affected the dispatch of different types of generation plant. The first generation fuel type we will examine will be the production intensity rates associated with coal-fired generation. These results are outlined in Figure F-3 for coal generation.

The most noticeable feature of Figure F-3 is the apparent increases in production intensity of each state occurring from 2011-12 to 2012-13 and continuing to 2013-14 for Victoria. The other noticeable aspect is the shift in magnitude of the production intensity rates, particularly in the case of Victoria which now has the highest production intensity rate. This is linked to the cheapness and must run requirements of the Victorian brown coal generation fleet especially when compared with the black coal fleets in Queensland and New South Wales, at least in terms of cost.

Figure F-3 Production intensity rate by state for 2009-10 to 2030-31 for \$0/tC0$_2$: coal generation



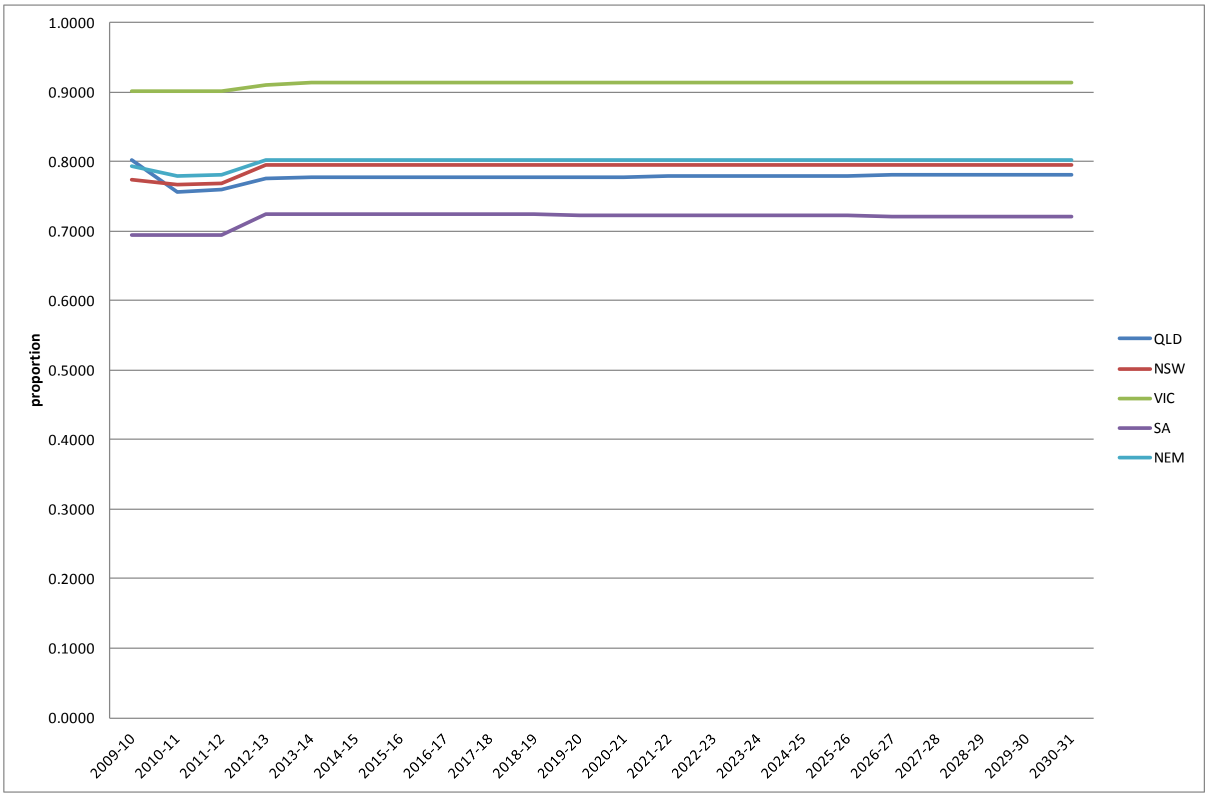
The other prominent feature of Figure F-3 is the very flat paths of the production intensity rates after 2012-13 which matches qualitatively, findings outlined in Figures F-1 and F-2 above. Thus, climate change seems to also have a benign effect on the intensity of dispatch of each states coal generation fleet over the period 2012-13 to 2030-31.

To assess whether the increases in production intensity rates observed in Figure F-3 represents an increase in the actual dispatch of operating coal plant or is a numeric effect of the averaging process during plant de-commissioning, we also recalculated the production intensity rates excluding the de-commissioned coal plant. These results are shown in Figure F-4.

Examination of Figure F-4 demonstrates that the increases in production intensity rates in Figure F-3 were mainly an artefact of the averaging process. The new amended production intensity rates in Figure F-4 show a much less marked expansion in production intensity rates over the period 2012-13 to 2013-14 associated with the genuine expansion in production by remaining coal plant in response to plant de-commissioning. The results for Queensland also reinforces the role that the newly commissioned NGCC plant played in replacing the lost capacity associated with the de-commissioning of Swanbank B.

Our observation about the benign impact that climate change seems to have on the production intensity of dispatch of coal plant over the period 2013-14 to 2030-31 also continues to hold. In order to quantity these impacts by state, the coal generation production intensity rate for Queensland increased from 0.7770 in 2013-14 to 0.7819 in 2030-31, a change of 0.63 of one per cent. For the other states, the equivalent values were 0.7952 to 0.7950 in New South Wales, 0.9140 to 0.9140 in Victoria and 0.7245 to 0.7208 for South Australia. In percentage changes terms, this amounted to slight reductions of -0.02 and -0.01 of one per cent for New South Wales and Victoria and a slightly larger reduction of around half a per cent for South Australia. For the NEM, these state trends translate into a marginal increase from 0.8027 in 2013-14 to 0.8029 in 2030-31, representing an increase of 0.03 of one per cent.

Figure F-4 Amended production intensity rate by state for 2009-10 to 2030-31 for \$0/tC0$_2$: coal generation

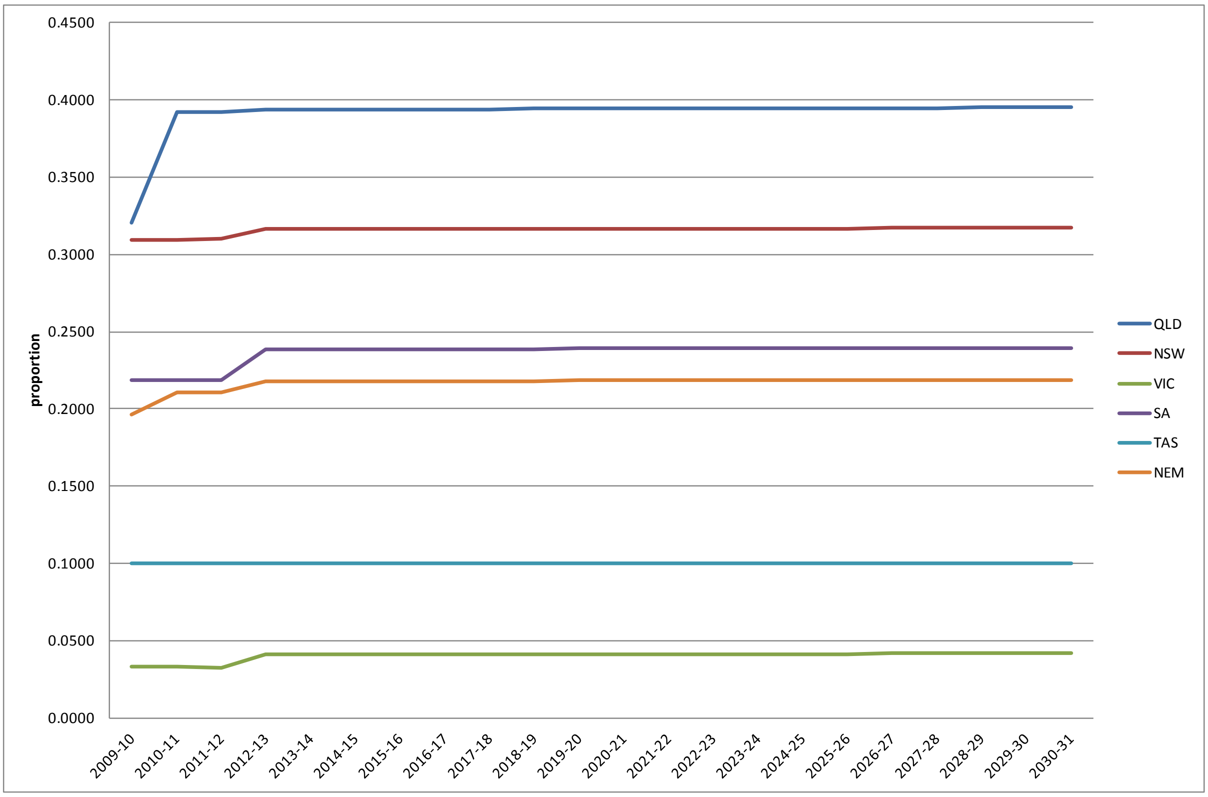


The next generation fuel type examined is gas-fired generation. These production intensity rates by state are documented in Figure F-5. Because there are no gas plant de-commissioned over the period 2009-10 to 2012-13, and production contributions of newly commissioned gas plant are only included in calculating production intensity rates from the commissioning year, we do not need to be concerned about the impact on production intensities of plant de-commissioning in this case.

The most noticeable feature of Figure F-5 is the marked increase in production intensity rate for Queensland in 2010-11, reflecting the commissioning of Yarwun, Darling Downs and unit 3 of Condamine as discussed above. This represents an increase from 0.3207 in 2009-10 to 0.3922 in 2010-11. More generally, there is a slight increase in the production intensity rates for Queensland, New South Wales, Victoria and South Australia in 2012-13 reflecting the increased dispatch of gas generation to help meet the fall in capacity occurring from the plant de-commissioning occurring in 2012-13. These increases are from 0.3924 to 0.3938 for Queensland, 0.3100 to 0.3163 for New South Wales, 0.0319 to 0.0410 for Victoria and, more significantly, from 0.2182 to 0.2384 for South Australia. As such, the increases are of a larger order of magnitude in South Australia, Victoria and New South Wales than in Queensland.

The other important feature to recognise from Figure F-5 is the significantly higher production intensity rates recorded for Queensland, New South Wales and South Australia when compared to Victoria and Tasmania. This reflects the prominence of baseload and intermediate NGCC, gas thermal and OCGT plant in these states gas fleets when compared to Victoria and Tasmania. Note that South Australia has a higher proportion of peak load OCGT plant when compared to Queensland and New South Wales which is why its production intensity rate is lower than the latter two states. The production intensity rates of Victoria, in particular, are at levels that would be associated with peak gas plant.

Figure F-5 Production intensity rate by state for 2009-10 to 2030-31 for $0/tC02: gas generation



Another noticeable feature of Figure F-5 is again, the rather benign impact that climate change seems to have on the production intensity of dispatch of gas plant over the period 2013-14 to 2030-31. To quantify this impact by state, the production intensity rate for Queensland increases from 0.3939 in 2013-14 to 0.3953 in 2030-31, a change of 0.36 of one per cent. For the other states, the equivalent values were 0.3164 to 0.3173 in New South Wales, 0.0413 to 0.0417 in Victoria and 0.2388 to 0.2393 for South Australia. In percentage changes terms, this amounts to slight increases of 0.29 and 0.23 of one per cent for New South Wales and South Australia and a slightly larger increase of 1.16 per cent in Victoria. For Tasmania, the production intensity rate of 0.1 stays the same over the entire period 2009-10 to 2030-31 reflecting the dispatch of the

Tamar Valley NGCC plant at levels close to its minimum stable operating level. None of the other OCGT plant is dispatched in Tasmania. For the NEM, these state trends translate into a slight increase from 0.2181 in 2013-14 to 0.2187 in 2030-31, representing an increase of 0.31 of one per cent.

One facet of climate change commonly mentioned in public debate is the expected tendency for the increased incidence of severe weather events to arise. We examine production intensity rates of the two main types of generation commonly used to meet peak load production duties. We would expect the incidence of peak load production duties to be highly correlated with extreme weather events that cause extreme movement in temperatures in summer or winter.

Table F-1 contains the production intensity rates associated with OCGT generation. It should be noted that the magnitude of the values between states differ substantially. In particular, the values associated with Queensland and New South Wales are higher in magnitude reflecting the higher proportion of OCGT plant capable of meeting intermediate production duties, namely Braemar 1 and 2 power stations in Queensland and Uranquinty power station in New South Wales. This contrasts with the situation in Victoria, in particular, that aligns more closely with production intensity rates associated with genuine peak load plant. Note that we did not include any results for Tasmania because the OCGT plant in that state was not dispatched over the interval of investigation.

Table F-1 Production intensity rate outcomes by state for the period 2009-10 to 2030-31: OCGT generation

Year	QLD	NSW	VIC	SA	NEM
2009-10	0.1479	0.1364	0.0174	0.0592	0.0722
2010-11	0.1476	0.1365	0.0174	0.0592	0.0721
2011-12	0.1476	0.1367	0.0174	0.0584	0.0720
2012-13	0.1479	0.1390	0.0266	0.0797	0.0786
2013-14	0.1479	0.1391	0.0268	0.0801	0.0788
2014-15	0.1479	0.1391	0.0269	0.0801	0.0788
2015-16	0.1480	0.1392	0.0268	0.0802	0.0788
2016-17	0.1480	0.1392	0.0268	0.0802	0.0788
2017-18	0.1480	0.1392	0.0268	0.0803	0.0789
2018-19	0.1480	0.1393	0.0269	0.0803	0.0789
2019-20	0.1480	0.1393	0.0269	0.0803	0.0789
2020-21	0.1480	0.1393	0.0269	0.0803	0.0789
2021-22	0.1480	0.1394	0.0268	0.0803	0.0789
2022-23	0.1481	0.1394	0.0269	0.0804	0.0790
2023-24	0.1481	0.1394	0.0269	0.0804	0.0790
2024-25	0.1481	0.1395	0.0269	0.0805	0.0790
2025-26	0.1482	0.1396	0.0269	0.0805	0.0790
2026-27	0.1482	0.1397	0.0270	0.0806	0.0791
2027-28	0.1482	0.1397	0.0270	0.0806	0.0791
2028-29	0.1483	0.1398	0.0272	0.0809	0.0792
2029-30	0.1483	0.1399	0.0272	0.0808	0.0792
2030-31	0.1484	0.1401	0.0273	0.0809	0.0793
%Change	0.31	0.71	1.81	1.04	0.70

It is apparent from Table F-1 that increases in production intensity rates occur in 2012-13 with the more noticeable increases arising in Victoria and South Australia. These results are shaded in yellow in the table.

Once again, the results in Table F-1 also point to a fairly benign impact that climate change seems to have on the production intensity rates of OCGT plant over the 2013-14 to 2030-31 period. To quantity this impact, the last row of Table F-1 contains the percentage increase in production intensity rates in 2030-31 relative to those in 2013-14. It is evident from this row that Victoria and South Australia experience the greatest rates of increase of 1.81 and 1.04 per cent, respectively. The increases are more modest in New South Wales and Queensland, amounting to 0.71 and 0.31 of one per cent. The percentage rate of increase for the NEM is 0.7 of a per cent.

The second type of peak load generation technology considered is hydro generation. The production intensity rates for hydro generation by state are outlined in Table F-2. Note that we did not include any results for Queensland because hydro generation units in that state were not dispatched over the period of investigation. It should also be noted from inspection of Table F-2 that the magnitudes of the values between the different states differ significantly. In particular, the values associated with New South Wales and Victoria is very small in magnitude and consistent with the dispatch of hydro plant in those states as peak load plant. This is what we expect, however, because the supply offers of the least expensive hydro units in those two states are constructed to shadow peak load gas plant. The higher values recorded for Tasmania, on the other hand, reflects the predominance of this form of generation in that state with hydro generation expected to meet baseload, intermediate and peak load duties.

It is also evident from Table F-2 that increases in production intensity rates occur in 2012-13, albeit at very much reduced magnitudes when compared with the other types of generation considered including OCGT generation discussed in Table F-1. These results are shaded in yellow in Table F-2.

Table F-2 Production intensity rate outcomes by state for the period 2009-10 to 2030-31: hydro generation

Year	NSW	VIC	TAS	NEM
2009-10	0.0002	0.0081	0.2189	0.0568
2010-11	0.0002	0.0081	0.2189	0.0568
2011-12	0.0002	0.0031	0.2189	0.0556
2012-13	0.0005	0.0034	0.2196	0.0559
2013-14	0.0005	0.0034	0.2196	0.0559
2014-15	0.0005	0.0034	0.2196	0.0559
2015-16	0.0005	0.0035	0.2195	0.0559
2016-17	0.0005	0.0035	0.2195	0.0559
2017-18	0.0005	0.0036	0.2194	0.0559
2018-19	0.0005	0.0036	0.2194	0.0559
2019-20	0.0005	0.0036	0.2193	0.0559
2020-21	0.0005	0.0037	0.2193	0.0559
2021-22	0.0006	0.0036	0.2192	0.0558
2022-23	0.0006	0.0037	0.2191	0.0559
2023-24	0.0006	0.0037	0.2190	0.0558
2024-25	0.0006	0.0038	0.2190	0.0558
2025-26	0.0006	0.0038	0.2189	0.0558
2026-27	0.0006	0.0039	0.2188	0.0558
2027-28	0.0006	0.0038	0.2187	0.0558
2028-29	0.0007	0.0041	0.2186	0.0558
2029-30	0.0007	0.0040	0.2185	0.0558
2030-31	0.0007	0.0042	0.2184	0.0558
%Change	45.51	22.47	-0.54	-0.09

It is also apparent from examining the production intensity rates over 2013-14 to 2030-31 that the impact of climate change operating through its effects on regional demand for electricity, once again, seems benign. In order to quantity this impact, the last row of Table F-2 contains the percentage increase in production intensity rates in 2030-31 relative to 2013-14. The sizable percentage increases recorded for New South Wales and Victoria should be treated with caution and account taken of the very small production intensity bases that these results are being derived from. A more interesting result is that of Tasmania which experiences a reduction in production intensity rate of around half a per cent. This result is consistent with the use of CSIRO-Mk3.5 GCM to quantify the impact of climate change because in Section 3.2.2, it was demonstrated that the CSIRO-Mk3.5 GCM tended to downplay the impact of climate change on temperature in both Queensland and Tasmania when compared to the other states.

F.2.1.1 Discussion

Perhaps the most noticeable observation contained in the results reported in the previous section was the relatively benign impact that the climate change impacts included in the regional demand profiles underpinning the $0/tC0$_2$ simulation had on the production intensity rates of all types of generation considered over the period 2013-14 to 2030-31. This result could reflect a number of different factors.

First, the averaging performed to get the state results listed in the previous section involved averaging across generators spread across numerous regions in each state. Therefore, to the extent that climate change might be expected to exert differential impacts across different regions within a state, then this source of variation would be lost in the averaging process used to calculate the state based results.

The measures used also involved temporal averaging across the hourly dispatch intervals within the financial year. In this averaging process, we would also lose information about such things as seasonal variation – for example, the differential impacts of climate change on electricity demand during winter and summer periods. Thus the analytic methods used were focused at looking broadly at average consequences or tendencies associated with climate change while ignoring regional or seasonal based variations that might be expected to emerge.

The averaging methods would be particularly applicable if the central tendencies implied in projected climate change impacts such as average temperature increases had estimable impacts on regional electricity demand and through this on generation supply response. The patterns observed over the 2013-14 to 2030-31, in particular, would be consistent with the impact of climate change gradually and smoothly evolving to affect electricity demand in a broadly similar way across the nodes within the transmission grid. However, if the main effect of climate change on electricity demand is though severe weather impacts implying instances of extreme variation in temperature in summer and winter of limited duration, than these impacts could well be averaged away in the process of deriving the state based measures used in this Appendix.

Therefore, there would be value in performing analysis on a more disaggregated region by region basis as well as also breaking up the time dimension to focus at least on summer and winter effects. If severe weather events are thought to govern demand responses, than value would also be found in concentrating analysis on these limited duration events.

It would also be worthwhile to perform analysis on the basis of half hourly dispatch intervals. In this context, it should be noted that the nodal demand equations in Sections 5.2 and 5.3 provided half hourly regional demand projections which were then averaged across two successive half hourly intervals to provide the hourly demand projections used in the ANEM model simulation. This averaging process in going from half hourly to hourly demand profiles would smooth out some of the variation that was present in the half hourly demand data. Moving to a half hourly dispatch interval would also have supply side implications by its effect on generator ramping constraints. The combination of more variable demand and more restrictive generator ramping constraints is likely to elicit a different generator supply response from ANEM model simulations than was obtained from the hourly based dispatch simulations reported in this Appendix. Moreover, moving from the 'n' transmission configuration to the 'n-1' configuration discussed in Section C.4 would also elicit a different generator supply response than obtained in the simulations reported in this Appendix. This would operate by having the reduced capacity of the transmission system potentially islanding generation thus requiring additional capacity to be sourced from elsewhere on the grid.

F.2.2 Impact of climate change on generation dispatch patterns for the period 2009-10 to 2030-31 in the presence of a carbon price of $23/tC0_2$

In this section, we assess the impact of a carbon price of $23/tC0_2$ on energy generated dispatch determined from ANEM model simulations. We examine this aspect from two particular perspectives. The first relates to the impact arising in 2009-10 and will be performed by calculating the percentage change in energy generated by state and fuel type associated with the carbon price against the levels calculated for 2009-10 from the $0/tC0_2$ simulation used in the previous section.

In the following section, we will examine the consequences of the carbon price when compared against a benchmark simulation conducted over the whole 2009-10 to 2030-31 time period which accounts for the impact of climate change on projected demand but in a policy environment containing no carbon price signal. This BAU scenario corresponds to the carbon price exclusive $0/tC0_2$ simulation results underpinning analysis in the previous section.

F.2.2.1 Carbon price impact on energy generated in 2009-10

The fuel-switching effects associated with the introduction of a carbon price of $23/tC0_2$ are identified in Table F-3. The values listed in each panel of Table F-3, for each state and fuel type considered, are the production intensity rates associated with the $0/tC0_2$ simulation (in the '$0' row), and the $23/tC0_2$ simulation (in the '$23' row). The last row in each panel is the percentage change calculation that, for the values in the '$23' and '$0' rows, is calculated as: % Change = [($23 - $0)/$0]*100.

The impact of the carbon price, for all sources of generation in each state, is listed in Table F-3, Panel (A). It is evident from this table that Victoria experiences the greatest decline in production intensity rate of -13.5 per cent. This is followed by South Australia (-2.2 per cent) and New South Wales (-1.3 per cent). Queensland and Tasmania experience increases in production intensity rates of 1.1 per cent and 39.4 per cent, respectively.

To investigate the driving forces behind these aggregate outcomes, we investigate the impact of the carbon price by state and by different fuel based generation technologies. Mirroring the approach adopted in the last section, this will includes coal, gas, OCGT and hydro generation.

The results for coal generation are listed in Table F-3, Panel (B). From assessment of this panel, it is evident that Victoria experiences the largest reduction in production intensity of coal generation amounting to a reduction of -14.3 per cent, followed by South Australia (-7.8 per cent), and then New South Wales (-1.7 per cent). Queensland experiences an increase in production intensity of 1.3 per cent. For the NEM, the production intensity rate of coal generation declines by 6.0 per cent, reflecting primarily the negative contributions of Victoria and South Australia. Note in particular the closeness of the results in Panel (B) with those in Panel (A) of Table F-3, indicating the importance of trends in coal generation in largely determining the aggregate results in relation to Victoria, Queensland and New South Wales. The aggregate results for South Australia, in contrast, reflect a combination of trends emerging in both the coal and gas generation sectors in that state.

A key factor explaining the trends in Panel (B) relate to the prominence of more thermally efficient and less carbon emissions intensive black coal generation in Queensland and New South Wales when compared with less thermally efficient and more carbon emissions intensive brown coal generation in Victoria and low-rank sub-bituminous black coal generation in South Australia. This means that the competitive position of production utilising black coal in the case of Queensland and New South Wales can withstand the variable carbon cost impost associated with the carbon price more readily than can brown coal generation in Victoria and low quality black coal generation in South Australia. Thus, coal generation in Victoria and South Australia is much more susceptible to the impost of variable carbon costs and the reductions observed in their production intensity rates reflect this.

The results for gas generation are outlined in Table F-3, Panel (C). From this panel, it is apparent that Victoria experiences the largest increase in the production intensity rate for gas generation of 3.3 per cent, followed by South Australia (0.3 of one per cent) and Queensland (0.1 of one per cent). New South Wales experiences a slight decline of -0.1 of a per cent while the position of Tasmania remains unchanged, reflecting the continued dispatch of the NGCC Tamar Valley power station at levels close to its minimum stable operating level. The results for Victoria should be interpreted with some caution because it is coming off reasonably low production intensity rates. This is borne out by the NEM result which signifies growth but at only 0.2 of a per cent.

The increase in production from Victorian gas plant would principally reflects the improved competitiveness of this type of generation relative to Victorian brown coal generation, thereby producing the displacement of production from brown coal generation. The expansion in production from gas generation in Queensland and South Australia would principally reflect the more intensive dispatch of NGCC plant at the carbon price level of $23/tC0$_2$. Finally, a factor contributing to the reduction experienced in New South Wales would be the increased import of power from Queensland, displacing production from gas generation at the margin.

Table F-3 ($23/tC0$_2$) and ($0/tC0$_2$) production intensity rates outcomes by state and fuel type for the 2009-10 benchmark year

Panel (A) All generation

Carbon Price	QLD	NSW	VIC	SA	TAS
$0	0.4391	0.3569	0.2749	0.2237	0.2081
$23	0.4439	0.3522	0.2378	0.2188	0.2901
% change	1.09	-1.32	-13.49	-2.19	39.39

Panel (B) Coal generation

Carbon Price	QLD	NSW	VIC	SA	NEM
$0	0.6702	0.7429	0.8633	0.5830	0.7149
$23	0.6791	0.7305	0.7400	0.5378	0.6718
% change	1.33	-1.67	-14.29	-7.76	-6.02

Panel (C) Gas generation

Carbon Price	QLD	NSW	VIC	SA	TAS	NEM
$0	0.3207	0.3095	0.0333	0.2189	0.1000	0.1965
$23	0.3211	0.3093	0.0344	0.2195	0.1000	0.1969
% change	0.12	-0.09	3.29	0.28	0.00	0.19

Panel (D) OCGT generation

Carbon Price	QLD	NSW	VIC	SA	NEM
$0	0.1479	0.1364	0.0174	0.0592	0.0722
$23	0.1478	0.1361	0.0186	0.0568	0.0719
% change	-0.06	-0.20	6.99	-4.04	-0.42

Panel (E) Hydro generation

Carbon Price	NSW	VIC	TAS	NEM
$0	0.0002	0.0081	0.2189	0.0568
$23	0.0005	0.0083	0.3091	0.0795
% change	146.99	2.04	41.19	39.88

The results for OCGT generation are outlined in Table F-3, Panel (D). It should be noted that we excluded Tasmania because no dispatch was recorded by Tasmanian OCGT plant in the model simulations. From this panel, it is apparent that Victoria experiences the largest increase in production intensity rate for OCGT generation of 7.0 per cent. All other states experience reductions of -4.0 per cent for South Australia, -0.2 of one per cent for New South Wales and -0.1 of one per cent for Queensland. The results for both South Australia and Queensland provide support for the proposition that the expansion in gas generation observed in Table F-3, Panel (C) would be coming principally from expansion in production from baseload NGCC plant. Notwithstanding Victoria's positive growth result, the result for the NEM indicates a reduction of -0.4 of a per cent.

The results for hydro generation are outlined in Table F-3, Panel (E). Note that we have excluded Queensland because no dispatch was recorded by Queensland hydro plant in model simulations. The most striking result from this panel is the increase in the production intensity rate for Tasmania of 41.2 per cent. In contrast, while the magnitude of the percentage increase recorded for New South Wales is quite large, it is coming off very small production intensity rates. However, in the case of Tasmania, the significant growth of 41.2 per cent is coming off much larger production intensity rates, signifying significant expansion in production from hydro generation in Tasmania.

One factor that would be producing this expansion in hydro production from Tasmania is the relative improvement in the competitive position of hydro generation relative to competing thermal plant in both Tasmania and Victoria following the imposition of the carbon price of $23/tC0$_2$. This follows because the carbon price does not affect the marginal costs of hydro generators whereas it increases the marginal costs of competing thermal generators.

Another important factor is the issue of location. Power exported from Tasmania flows into Victoria on the Basslink Interconnector which connects into the La Trobe Valley at the Loy Yang node – see Appendix B. Most of the Victorian brown coal generators affected by the carbon price are also located in the La Trobe Valley. Therefore, power flows from Tasmania are well placed to displace production of Victorian brown coal generation if the competitive position of the latter generators deteriorates when compared with competing hydro generation. This issue of location is important when one considers the much more modest increase in production sourced from hydro generation located in Victoria (of 2.0 per cent). A reason for this is that the cheapest mainland hydro units are assumed to shadow peak load gas plant while some hydro generators in Tasmania are assumed to meet baseload or intermediate production duties. In this latter case, they are likely to have cost structures significantly lower than their mainland counterparts, giving them a competitive advantage relative to their mainland counterparts.

Finally, the importance of Tasmania can be seen in Table F-3, Panel (E) by the fact that the NEM results closely follow it. This is the case because the production intensity rate of Tasmania clearly dominates that of the other states in the case of hydro generation.

F.2.2.2 Carbon price impact over the period 2009-10 to 2030-31

In this section, we examine the consequences of the carbon price when compared against a benchmark simulation conducted over the whole 2009-10 to 2030-31 time period which accounts for the impact of climate change on projected demand but in a policy environment containing no carbon price signal. The benchmark simulation is the carbon price exclusive $0/tC0$_2$ simulation while the simulation associated with the carbon price is the carbon price inclusive $23/tC0$_2$ simulation.

The key metric used in this section is a percentage rate of change calculation conducted on a year-on-year basis over the period 2009-10 to 2030-31 constructed as: % Change = [($23 - $0)/$0]*100. Note '$23' is the production intensity rates by state and fuel type from the carbon price inclusive $23/tC0$_2$ simulation whereas '$0' denotes the equivalent production intensity rates from the carbon price exclusive $0/tC0$_2$ simulation. In this context, the sign associated with the percentage change rates will establish whether the imposition of a carbon price of $23/tC0$_2$ would increase or decrease the production intensity rates when compared to the rates obtained from the $0/tC0$_2$ simulation.

It should also be recognised that the nature of the year-on-year comparison that is proposed ensures that we are comparing across similar generation and demand structures. The only variable that changes between the simulations being compared on a year-on-year basis is the carbon price level itself.

The percentage change results obtained in relation to all sources of generation by state are listed in Table F-4. It is evident from this table that the impact of the carbon price is to increase the production intensity rates for Queensland and Tasmania relative to the $0/tC0$_2$ rates but at a diminishing rate over the period 2009-10 to 2030-31. In the case of New South Wales, the carbon price reduces the production intensity rate relative to the $0/tC0$_2$ rate at an increasing rate particularly over the period 2013-14 to 2030-31. For Victoria and South Australia, the carbon price also reduces the production intensity rates of both states relative to the $0/tC0$_2$ rates, however, at a diminishing rate over time in the interval 2013-14 to 2030-31.

Table F-4 Percentage change between the ($23/tC0$_2$) and ($0/tC0$_2$) production intensity rate outcomes by state for the period 2009-10 to 2030-31: all generation

Year	QLD	NSW	VIC	SA	TAS
2009-10	1.09	-1.32	-13.49	-2.19	39.39
2010-11	0.95	-0.75	-13.17	-2.14	37.80
2011-12	0.88	-0.82	-12.42	-2.09	30.46
2012-13	0.75	-0.66	-11.46	-1.70	35.49
2013-14	0.60	-0.73	-9.53	-1.70	23.02
2014-15	0.55	-0.86	-8.96	-1.62	21.46
2015-16	0.55	-0.88	-8.71	-1.58	16.18
2016-17	0.55	-0.88	-8.69	-1.51	15.46
2017-18	0.55	-0.78	-8.49	-1.49	13.51
2018-19	0.56	-0.80	-8.40	-1.42	12.88
2019-20	0.55	-0.99	-7.75	-1.35	12.47
2020-21	0.55	-0.93	-4.07	-1.31	4.36
2021-22	0.55	-0.91	-4.03	-1.22	4.06
2022-23	0.55	-0.91	-4.04	-1.24	3.94
2023-24	0.54	-0.87	-3.97	-1.20	3.39
2024-25	0.55	-0.85	-3.95	-1.16	3.03
2025-26	0.55	-0.91	-3.65	-1.08	2.81
2026-27	0.55	-0.98	-3.36	-1.05	2.64
2027-28	0.56	-0.99	-3.27	-0.98	2.49
2028-29	0.54	-1.00	-3.29	-1.00	2.38
2029-30	0.54	-1.00	-3.22	-0.88	2.19
2030-31	0.53	-1.01	-3.23	-0.84	1.98

Table F-5 shows the percentage change results obtained in relation to coal generation by state. From inspection of this table, it is apparent that the impact of the carbon price is to increase the production intensity rates of Queensland relative to the $0/tC0$_2$ rates at an increasing rate over the period 2009-10 to 2030-31. For New South Wales, the carbon price reduces the production intensity rate relative to the $0/tC0$_2$ rate at an increasing rate particularly over the period 2013-14 to 2030-31. For Victoria and South Australia, the carbon price also reduces the production intensity rates of both states, however, at diminishing rates over time in the interval 2013-14 to 2030-31. For the

NEM, the effect of the carbon price is to reduce the production intensity rate for coal generation at a diminishing rate over the period 2009-10 to 2030-31. This result matches the results reported for Victoria and South Australia in particular, pointing to those states relative importance in determining what happens to aggregate coal generation in the NEM following the imposition of a carbon price of $23/tC0_2$.

Table F-5 Percentage change between the ($23/tC0_2$) and ($0/tC0_2$) production intensity rate outcomes by state for the period 2009-10 to 2030-31: coal generation

Year	QLD	NSW	VIC	SA	NEM
2009-10	1.33	-1.67	-14.29	-7.76	-6.02
2010-11	0.02	-0.95	-13.94	-7.68	-6.04
2011-12	0.22	-1.04	-13.06	-7.62	-5.70
2012-13	0.38	-0.83	-12.22	-1.71	-3.92
2013-14	0.58	-0.92	-10.21	-1.77	-3.40
2014-15	0.66	-1.08	-9.61	-1.76	-3.24
2015-16	0.68	-1.10	-9.34	-1.76	-3.16
2016-17	0.69	-1.10	-9.31	-1.63	-3.12
2017-18	0.70	-0.98	-9.10	-1.61	-3.02
2018-19	0.73	-1.00	-9.00	-1.48	-2.97
2019-20	0.73	-1.24	-8.31	-1.35	-2.80
2020-21	0.74	-1.17	-4.39	-1.35	-1.66
2021-22	0.75	-1.15	-4.38	-1.32	-1.65
2022-23	0.75	-1.15	-4.37	-1.32	-1.64
2023-24	0.74	-1.10	-4.29	-1.31	-1.61
2024-25	0.75	-1.08	-4.26	-1.28	-1.59
2025-26	0.75	-1.15	-3.97	-1.27	-1.52
2026-27	0.75	-1.24	-3.63	-1.28	-1.45
2027-28	0.76	-1.26	-3.56	-1.28	-1.43
2028-29	0.75	-1.27	-3.54	-1.28	-1.43
2029-30	0.75	-1.26	-3.51	-1.21	-1.40
2030-31	0.75	-1.27	-3.51	-1.20	-1.40

In Table F-6, the percentage change in production intensity rates for gas generation by state is documented. Note that we have excluded the results for Tasmania from the table because the carbon price did not cause any shift in production intensity rates from those recorded under the $0/tC0_2$ simulation. From examination of this table, it is clear that the impact of the carbon price is to increase the production intensity rates of Queensland relative to the $0/tC0_2$ rates, however, at a diminishing rate over the period 2013-14 to 2030-31. In the case of both New South Wales and South Australia, the carbon price reduces the production intensity rates relative to the $0/tC0_2$ rates at a diminishing rate over the period 2013-14 to 2030-31. For Victoria, it is difficult to discern a general trend over time with both negative and positive contributions occurring over the period 2013-14 to 2030-31. Overall, the impact seems to diminish over time although there are clear outliers from this trend. For the NEM, the effect of the carbon price is to reduce the production intensity rate for gas generation at a diminishing rate over the period 2014-15 to 2030-31. This result broadly matches the results reported for New South Wales and South Australia.

Table F-6 Percentage change between the (\$23/tC0$_2$) and (\$0/tC0$_2$) production intensity rate outcomes by state for the period 2009-10 to 2030-31: gas generation

Year	QLD	NSW	VIC	SA	NEM
2009-10	0.12	-0.09	3.29	0.28	0.19
2010-11	3.01	-0.11	2.91	0.33	1.25
2011-12	2.33	-0.15	2.41	0.39	0.98
2012-13	1.48	-0.45	0.41	-1.70	0.05
2013-14	0.65	-0.45	0.18	-1.69	-0.26
2014-15	0.32	-0.44	0.09	-1.60	-0.36
2015-16	0.30	-0.43	0.12	-1.54	-0.35
2016-17	0.28	-0.42	0.04	-1.49	-0.35
2017-18	0.25	-0.41	0.04	-1.47	-0.35
2018-19	0.22	-0.40	-0.12	-1.41	-0.35
2019-20	0.20	-0.39	-0.08	-1.35	-0.34
2020-21	0.17	-0.38	-0.03	-1.30	-0.33
2021-22	0.16	-0.36	0.22	-1.22	-0.31
2022-23	0.15	-0.35	0.23	-1.22	-0.31
2023-24	0.15	-0.34	0.07	-1.18	-0.30
2024-25	0.15	-0.33	0.03	-1.14	-0.29
2025-26	0.15	-0.33	0.09	-1.05	-0.27
2026-27	0.15	-0.33	-0.12	-1.01	-0.27
2027-28	0.15	-0.31	0.18	-0.93	-0.23
2028-29	0.13	-0.32	-0.06	-0.94	-0.25
2029-30	0.12	-0.30	0.16	-0.82	-0.22
2030-31	0.10	-0.30	0.13	-0.78	-0.22

The percentage change in production intensity rates for hydro generation by state are outlined in Table F-7. Note that we have excluded the results for Queensland from the table because no dispatch was obtained from Queensland hydro generation plant under either the \$0/tC0$_2$ or \$23/tC0$_2$ simulations. From inspection of this table, it is apparent that the impact of the carbon price is to increase the production intensity rates of hydro generation for both New South Wales and Tasmania relative to the \$0/tC0$_2$ rates. These trends, however, occur at diminishing rates over the period 2009-10 to 2030-31. In the case of Victoria, it is more difficult to discern a general trend over time although the contribution of the carbon price is to definitely increase the production intensity rate relative to the \$0/tC0$_2$ rates. Whilst, in general terms, the trend is towards a diminishing impact over time, there are some outliers against this general trend appearing within the interval 2013-14 to 2030-31. For the NEM, the effect of the carbon price is to increase the production intensity rate for hydro generation relative to the \$0/tC0$_2$ production intensity rates for hydro generation. However, this trend also occurs at a diminishing rate over the period 2014-15 to 2030-31, matching the results observed for New South Wales and Tasmania.

Table F-7 Percentage change between the ($23/tC$0_2$) and ($0/tC0_2) production intensity rates outcomes by state for the period 2009-10 to 2030-31: hydro generation

Year	NSW	VIC	TAS	NEM
2009-10	146.99	2.04	41.19	39.88
2010-11	150.47	2.10	39.53	38.29
2011-12	216.24	6.06	31.85	31.64
2012-13	185.77	11.44	37.10	37.04
2013-14	179.13	11.26	24.07	24.21
2014-15	171.13	10.65	22.44	22.58
2015-16	163.48	10.43	16.92	17.15
2016-17	156.40	10.26	16.16	16.39
2017-18	149.78	10.05	14.13	14.38
2018-19	144.22	9.83	13.47	13.72
2019-20	139.29	9.55	13.04	13.29
2020-21	133.32	9.09	4.56	4.95
2021-22	125.99	11.54	4.25	4.67
2022-23	120.42	8.47	4.12	4.49
2023-24	113.49	8.35	3.55	3.92
2024-25	109.76	8.05	3.17	3.54
2025-26	105.92	10.40	2.93	3.35
2026-27	100.14	7.62	2.76	3.12
2027-28	97.56	10.20	2.60	3.00
2028-29	89.80	4.62	2.49	2.79
2029-30	83.49	9.61	2.29	2.66
2030-31	74.19	7.00	2.07	2.39

F.2.2.3 Discussion

In this section, the main themes from the results reported in the previous section will be brought together. The focus of this section will be the trends emerging over time from the year-on-year comparisons.

In the case of Queensland, the carbon price impact overtime acts to reinforce the growth in production from coal and gas generation associated with the $0/tC$0_2$ simulation results which contain climate change impacts. However, this reinforcement diminishes over the period 2013-14 to 2030-31.

For New South Wales, the impact of the carbon price over time is to reinforce the slight decline experienced in the production intensity rate of coal generation associated with the $0/tC$0_2$ simulation over the period 2013-14 to 2030-31. The impact is similar also for gas generation producing reductions over time in production levels from New South Wales gas generation when compared with the $0/tC$0_2$ simulation results. However, unlike the case with coal generation, this effect diminishes over time. The impact of the carbon price is to also reinforce the expansion that was observed in hydro production associated with the $0/tC$0_2$ simulation. This positive reinforcement, however, diminishes over the 2013-14 to 2030-31 period of investigation and is coming off small production intensity rates. In overall terms, the trends identified over 2013-14 to 2030-31 in relation to coal generation, in particular, appears to have the dominating effect with the impact of the carbon price for the 'all generation' production intensity rate over this time period mirroring that of coal generation, albeit at a slightly reduced magnitude.

For Victoria, the impact of the carbon price is too strongly reinforce the slight trend reduction in the production intensity rate of coal generation associated with the \$0/tC0_2 simulation over the period 2013-14 to 2030-31. This negative reinforcement, however, declines in magnitude over the duration of this time interval. Determining a definitive time trend for the impact of the carbon price on gas generation is more difficult, although, on a year-on-year basis, it has more positive contributions than negative contribution. Thus overall, it would tend to reinforce the positive growth in production intensity rate for Victorian gas generation observed in the results from the \$0/tC0_2 simulation for the period 2013-14 to 2030-31. A similar trend also occurs for Victorian hydro generation, although the impact of the carbon price in this case is always towards positive reinforcement of the \$0/tC0_2 simulation results. However, from the nature of the variation in the reinforcement effects over the period 2013-14 to 2030-31, it is not possible to draw definitive conclusions about whether this impact is diminishing or increasing over time. It is also coming off very low production intensity rates. In overall terms, Victoria's 'all generation' trend closely matches the trend observed for coal generation in terms of both the sign of the contribution and its trend over time. This emphasises the importance of coal generation in Victoria and the low production intensity rates underpinning Victorian gas and hydro production.

The impact of the carbon price is to reinforce the reduction in the production intensity rate of coal generation from the \$0/tC0_2 simulation over the period 2013-14 to 2030-31 in South Australia. This negative reinforcement however occurs at a diminishing rate over the period 2012-14 to 2030-31. The effect of the carbon price also acts to moderate the expansion in gas generation observed under the \$0/tC0_2 simulation over the period 2013-14 to 2030-31, albeit, at a diminishing rate. Overall, the impact of the carbon price on the 'all generation' production intensity rate mirrors the impacts associated with coal and gas generation. It has the effect of reducing the production intensity rate of South Australia relative to the rates obtained from the \$0/tC0_2 simulation but at a diminishing magnitude over the period 2013-14 to 2030-31.

In the case of Tasmania, the main impact of the carbon price is to reinforce the expansion in hydro generation associated with the \$0/tC0_2 simulation but at a diminishing rate over the period 2013-14 to 2030-31. The 'all generation' results for Tasmania closely match the results obtained for hydro generation.

Therefore, in summary, the above analysis demonstrates the similarity in outcomes for both Queensland and Tasmania. There is growth in production intensity rates, however, at a declining rate over the time period 2013-14 to 2030-31. This growth occurs from different types of generation. In Queensland, it is growth in both coal and gas generation that is driving the results while in Tasmania, it is growth in hydro generation. These results are consistent with the use of CSIRO-Mk3.5 GCM to quantify the impact of climate change because this GCM downplays the impact of climate change on temperature in both Queensland and Tasmania when compared to the other states.

This would explain the nature of the diminishing rate of positive reinforcement experienced by both states over time.

The other two states experiencing similar outcomes are Victoria and South Australia. The key impact of the carbon price is to reduce the production intensity rates obtained relative to those rates associated with the $0/tC$0_2$ simulation. However, over time, this fuel-switching effect associated with the carbon price declines in strength ensuring that the magnitude of the reductions in generation from coal and gas generation diminish over time. It should be noted that these results are consistent with the use of CSIRO-Mk3.5 GCM to enumerate the impact of climate change because this GCM produces to most severe impacts of climate change on temperature in Victoria and South Australia. This effect would help to explain why the fuel-switching effect associated with the carbon price diminishes in strength for both states over time.

The state with the most mixed results is New South Wales. The impact of the carbon price reinforces a decline experienced in coal generation and moderates expansions occurring in gas generation. The magnitude of these combined impacts also increases slightly in magnitude over the time period 2013-14 to 2030-31 as shown in Table F-4. Therefore, the overall trend effect in New South Wales over time is towards a reduction in the production intensity rate of both 'all generation' and coal generation in an environment of increasing demand flowing from the impact of climate change.

A possible explanation of these trends is the substitution of New South Wales production by production from Queensland. Specifically, Queensland experiences positive growth in both coal and gas generation over the whole period of investigation 2009-10 to 2030-31. However, this state is affected to a less degree than New South Wales from climate change impact projections associated with of CSIRO-Mk3.5 GCM. Moreover, most of the newly commissioned NGCC plant in Queensland as well as the coal plant located in the South West Queensland node are well placed to export power into New South Wales on the QNI Interconnector – see Appendix B. In this context, the Queensland coal generators located at the South West Queensland node are of newer vintage compared to the New South Wales generators located at Liddell, Bayswater and Central Coast nodes, in particular. They also have better thermal, carbon emission intensity properties and lower fuel costs than their New South Wales counterparts. This gives the Queensland coal generators a distinct competitive advantage over their New South Wales counterparts which is likely to be enhanced with the imposition of a carbon price of $23/tC$0_2$. This, in turn, is capable of promoting substitution of coal based generation from New South Wales by coal based generation from Queensland. This outcome is consistent with the production intensity rate trends listed in Tables F-4 to F-6.

G CARBON EMISSIONS BY STATE AND FUEL TYPE

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This Appendix outlines the methodology and results from ANEM model simulations based on the projected regional demand profiles for years 2009-10 to 2030-31 to answer the fourth research question:

4. *Comparing the effect of climate change on carbon emissions between the years 2009-10 and 2030-31 with and without a carbon price.*

We investigate in subsequent sections, the methodology used to address this research question and the results obtained from ANEM market simulations.

G.1 Methodology

The objective of this Appendix is to assess the implications of climate change on carbon emissions by state where the main 'transmission' mechanism through which climate change operates is through its impact on electricity demand as outlined in chapter 5.

The ANEM model simulations performed for this investigation utilise projected regional demand profiles based upon the nodal demand equations presented in Sections 5.2 and 5.3. In Section 7.1 and Appendix D, the close correspondence between the results of ANEM model simulations based on actual and projected 2009-10 demand profiles was established for total carbon emissions by state and fuel type. This outcome allows us to proceed with confidence to use the ANEM model to make comparisons between the years 2009-10 and 2030-31 based on the demand projections for those years relating to total carbon emissions by state and fuel type.

Section E.2 discusses the general methodology employed to ascertain the key consequences of climate change on the NEM. In this Appendix, we adopt the same methodological approach as outlined in Section E.2 with regard to the choice of BAU baselines and carbon price settings.

To assess the impact of climate change on carbon emissions, we will be concerned with ANEM simulation outcomes related to carbon emissions by state obtained from all sources of generation. In order to better understand these aggregate state trends, however, we will also report carbon emission outcomes from coal and gas generation by state.

We adopt the same formula as outlined in Section E.3 to calculate growth rate metrics taking into account how its application might change with BAU baseline as explained in Section E.3.

To calculate the level of carbon emissions in any year, we sum daily $C0_2$ emissions time series produced by the ANEM model for each generator located at a node within each state over the year. The aggregate state figures are then obtained by summing the former results across all generators within the state and by fuel type. The NEM aggregate is calculated by totalling the aggregate state carbon emission totals. Note that the nodal location of generators within each state is outlined in Appendix B.

G.2 Results

The results associated with the output metric mentioned above are presented in the next two sections. The first set of results will detail outcomes from carbon price exclusive ($0/tC0_2$) simulations. This will relate to the impact of climate change on carbon emissions in the absence of a carbon price. The second set of results reported in the following section will relate to carbon price inclusive ($23/tC0_2$) simulations in which the carbon price was set to $23/tC0_2$.

G.2.1 Impact of climate change on carbon emissions for the period 2009-10 to 2030-31 in the absence of a carbon price

The first set of results are reported in Table G-1 and relate to the percentage change in carbon emissions from 2009-10 BAU levels associated with the carbon price exclusive ($0/tC0_2$) simulations for the period 2010-11 to 2030-31. The aggregate state results are outlined in Panel (A), followed by the results associated with coal generation in Panel (B) and results associated with gas generation in Panel (C).

From inspection of Panel (A), some step changes in carbon emission outcomes occur over the period 2009-10 to 2013-14. In the case of Queensland, there are a series of reductions occurring over the period 2010-11 to 2012-13 principally associated with the decommissioning of Swanbank B power station over this time frame. These results can also been seen in Panel (B) which documents reduction in carbon emissions from coal generation. From this panel, we see a -5.9 per cent reduction in 2010-11, increasing in magnitude to -6.1 in 2011-12 and -6.3 per cent in 2012-13. Note also that the sizable percentage increases in Panel (C) in the order of 65 per cent in carbon emissions over the period 2010-11 to 2012-13 from the newly commissioned Queensland NGCC plant goes some way to partially offsetting the reduction in emissions associated with the de-commissioning of Swanbank B.

For New South Wales, there is no real noticeable change in overall terms over the period 2010-11 to 2012-13 although there is a ramp up in carbon emission from gas generation in 2012-13 from 0.2 to 2.4 per cent, most likely in response to the closure of Munmorah Power station. See Panel (C) of Table G-1 for details.

In the case of Victoria, in Panel (A) there is a step change from 0.1 to -0.4 of one per cent in 2012-13 associated with the first stage of de-commissioning of Energy Brix power station, followed by a further reduction to -0.7 of a per cent in 2013-14 with the completion of this de-commissioning process in that year. These results are also borne out in Panel (B) of Table G-1, encompassing reductions in emission from coal generation of -0.01 to -0.6 then to -0.9 over the same time period. There is also ramp up in carbon emissions from gas generation, however, mainly occurring in 2012-13 in

Panel (C) with an increase from 4.5 per cent in 2011-12 to 12.0 per cent in 2012-13, followed by a further increase to 12.3 per cent in 2013-14. These results associated gas generation provide some partial counter-balancing to the reduction attributable to the de-commissioning of Energy Brix.

The results for South Australia indicate in Panel (A) a sizable step reduction in carbon emissions occurring in 2012-13 associated with the de-commissioning of Playford B power station, with a reduction from -0.1 of one per cent in 2011-12 to -12.7 per cent in 2012-13. This is also borne out in Panel (B) with reductions from 0.1 of one per cent in 2011-12 to -28.5 per cent in 2012-13. There is significant offsetting by growth in carbon emission from gas generation in South Australia increasing from -0.2 per cent in 2011-12 to 4.7 per cent in 2012-13 - see Panel (C) of Table G-1. Finally, there is no change in carbon emissions in Tasmania over the period 2009-10 to 2013-14 because the Tamar valley NGCC plant continues to be dispatched at production levels close to its minimum stable operating level over this period.

Table G-1 Percentage change in carbon emissions by state from 2009-10 levels for the period 2010-11 to 2030-31

Panel (A) all generation

Year	QLD	NSW	VIC	SA	TAS	NEM
2010-11	-2.51	-0.76	-0.01	-0.03	0.00	-0.97
2011-12	-2.63	-0.64	0.07	-0.12	0.00	-0.94
2012-13	-2.82	-0.63	-0.44	-12.71	0.00	-1.75
2013-14	-2.79	-0.55	-0.70	-12.62	0.00	-1.79
2014-15	-2.78	-0.55	-0.70	-12.62	0.00	-1.79
2015-16	-2.76	-0.56	-0.70	-12.63	0.00	-1.79
2016-17	-2.74	-0.56	-0.70	-12.63	0.00	-1.78
2017-18	-2.72	-0.56	-0.70	-12.63	0.00	-1.78
2018-19	-2.70	-0.56	-0.70	-12.64	0.00	-1.77
2019-20	-2.69	-0.56	-0.70	-12.64	0.00	-1.77
2020-21	-2.67	-0.56	-0.69	-12.65	0.00	-1.76
2021-22	-2.63	-0.57	-0.69	-12.65	0.00	-1.76
2022-23	-2.60	-0.57	-0.69	-12.66	0.00	-1.75
2023-24	-2.87	-0.90	-0.97	-13.00	-0.27	-2.04
2024-25	-2.83	-0.90	-0.97	-13.00	-0.27	-2.04
2025-26	-2.80	-0.90	-0.97	-13.01	-0.27	-2.03
2026-27	-2.76	-0.90	-0.97	-13.01	-0.27	-2.01
2027-28	-2.72	-0.90	-0.96	-13.02	-0.27	-2.00
2028-29	-2.68	-0.90	-0.96	-13.02	-0.27	-1.99
2029-30	-2.64	-0.90	-0.96	-13.02	-0.27	-1.98
2030-31	-2.60	-0.90	-0.96	-13.02	-0.27	-1.97
%Change	0.20	-0.35	-0.26	-0.46	-0.27	-0.17

Panel (B) coal generation

Year	QLD	NSW	VIC	SA	NEM
2010-11	-5.93	-0.78	-0.01	-0.06	-1.94
2011-12	-6.07	-0.67	-0.01	0.06	-1.93
2012-13	-6.30	-0.72	-0.65	-28.53	-2.98
2013-14	-6.27	-0.64	-0.92	-28.45	-3.03
2014-15	-6.25	-0.64	-0.92	-28.46	-3.03
2015-16	-6.24	-0.65	-0.92	-28.48	-3.03
2016-17	-6.22	-0.65	-0.92	-28.49	-3.02
2017-18	-6.20	-0.65	-0.92	-28.51	-3.02
2018-19	-6.18	-0.65	-0.92	-28.53	-3.02
2019-20	-6.16	-0.66	-0.92	-28.54	-3.01
2020-21	-6.14	-0.66	-0.92	-28.56	-3.01
2021-22	-6.11	-0.66	-0.92	-28.58	-3.00
2022-23	-6.08	-0.66	-0.93	-28.61	-2.99
2023-24	-6.33	-0.99	-1.19	-28.87	-3.28
2024-25	-6.30	-0.99	-1.19	-28.90	-3.27
2025-26	-6.27	-1.00	-1.19	-28.92	-3.26
2026-27	-6.23	-1.00	-1.19	-28.95	-3.26
2027-28	-6.19	-1.00	-1.19	-28.98	-3.25
2028-29	-6.15	-1.00	-1.19	-29.01	-3.24
2029-30	-6.11	-1.00	-1.19	-29.03	-3.23
2030-31	-6.08	-1.00	-1.19	-29.06	-3.22
%Change	0.21	-0.36	-0.27	-0.85	-0.19

Panel (C) gas generation

Year	QLD	NSW	VIC	SA	TAS	NEM
2010-11	65.00	0.04	0.04	0.01	0.00	16.09
2011-12	65.06	0.19	4.49	-0.24	0.00	16.47
2012-13	65.75	2.40	12.05	4.67	0.00	19.91
2013-14	65.77	2.44	12.30	4.77	0.00	19.99
2014-15	65.79	2.45	12.36	4.77	0.00	20.01
2015-16	65.81	2.47	12.40	4.78	0.00	20.02
2016-17	65.83	2.48	12.43	4.78	0.00	20.03
2017-18	65.86	2.50	12.49	4.79	0.00	20.05
2018-19	65.88	2.52	12.54	4.80	0.00	20.07
2019-20	65.91	2.53	12.60	4.81	0.00	20.09
2020-21	65.93	2.54	12.67	4.82	0.00	20.11
2021-22	65.98	2.57	12.72	4.83	0.00	20.14
2022-23	66.03	2.60	12.80	4.85	0.00	20.17
2023-24	65.58	2.12	11.76	4.43	-0.27	19.67
2024-25	65.63	2.15	11.87	4.44	-0.27	19.71
2025-26	65.68	2.18	11.99	4.46	-0.27	19.74
2026-27	65.74	2.22	12.13	4.48	-0.27	19.79
2027-28	65.80	2.26	12.28	4.50	-0.27	19.84
2028-29	65.86	2.30	12.43	4.52	-0.27	19.89
2029-30	65.93	2.35	12.58	4.55	-0.27	19.94
2030-31	66.00	2.40	12.73	4.58	-0.27	19.99
%Change	0.14	-0.04	0.38	-0.18	-0.27	0.00

The other noticeable feature evident in all panels of Table G-1 is the relatively benign growth in carbon emissions over the time period 2013-14 to 2030-31. This outcome is not unexpected given the benign trends observed previously in relation to production intensity rates over this same time period that was identified in Appendix F. The last row of each panel contains percentage growth in carbon emissions in 2030-31 relative to the levels in 2013-14. For all sources of generation, these growth rates outlined in Panel (A) are in the range of -0.46 to 0.20 of one per cent. Similarly, the equivalent outcomes listed in Panel (B) for coal generation are in the range -0.85 to 0.21 of one per cent. For gas generation, the differences listed in Panel (C) are in the range -0.27 to 0.38 of one per cent.

It follows from inspection of Table G-1 that Queensland experiences growth in carbon emissions over the period 2013-14 to 2030-31 with growth in carbon emissions from coal and gas generation also occurring. For New South Wales, further reductions in carbon emissions occur in 2030-31 relative to the levels in 2013-14. The principal driving force behind this trend is reductions in carbon emissions from coal generation particularly over the period 2023-24 to 2030-31. The experience for Victoria and South Australia is similar to that of New South Wales except that growth in carbon emissions from gas generation over the period 2013-14 to 2030-31 plays a partial counter-balancing role in the case of Victoria.

Note that the slight trend increase in the size of carbon emission reductions associated with coal generation in New South Wales, Victoria and South Australia for the period 2013-14 to 2030-31 listed in Panel (B) of Table G-1 are consistent with the production intensity rate outcomes identified in Section F.2.1. Recall that these production trends involved slight reductions in the coal production intensity rates over the same period of -0.02, -0.01 and -0.5 of a per cent for these three states, respectively. In this context, note that the magnitude of the percentage reduction in Panel (B) for South Australia exceeds the magnitude of the percentage differences associated with New South Wales and Victoria.

It is also evident from Panel (C) of Table G-1 that the carbon emissions produced from gas generation in New South Wales and South Australia decline slightly over the time period 2013-14 to 2030-31. This outcome is somewhat at odds with the slight increases recorded for gas generation production in those two states over the period 2013-14 to 2030-31, which involved slight increases of 0.29 and 0.23 of a per cent respectively – see Section F.2.1 for details. One possible explanation of such a trend would be the substitution of production from OCGT plant by production from NGCC or gas thermal plant over time. This would be likely to arise in an environment where coal generation was declining as was the case in these two states over this same time period. This follows because NGCC and gas thermal plant have cheaper marginal cost structures than peak load OCGT plant and can also be run as baseload or intermediate plant. As such, they have a clear competitive advantage over peak load OCGT plant and the technical advantage of being able to replace coal generation in its baseload or intermediate production roles. Finally, both New South Wales and South Australia have a much higher proportion of this type of plant in their gas generation portfolios than does Victoria. In fact, it is noticeable that Victoria, in contrast to New South Wales and South Australia, experiences positive growth in carbon emissions from gas generation in Panel (C) over the period 2013-14 to 2030-31 while also experiencing positive growth in gas generation production. The main difference is that Victoria has a much higher proportion of peak load OCGT plant than does New South Wales or South Australia. This latter type of gas generation plant has much higher carbon intensity rates when compared especially with the carbon intensity rates associated with NGCC plant.

G.2.2 Impact of climate change on carbon emissions for the period 2009-10 to 2030-31 in the presence of a carbon price of $23/tC0$_2$

In this section, we assess the impact of a carbon price of $23/tC0$_2$ on carbon emission outcome by state and fuel type determined from ANEM model simulations. We examine this from two particular perspectives. The first relates to the impact arising in 2009-10 and will be performed by calculating the percentage change in carbon emissions associated with the carbon price against the levels calculated from the 2009-10 BAU carbon price exclusive ($0/tC0$_2$) simulation used in the previous section.

In a following section, we examine the consequences of the carbon price when compared against a benchmark simulation conducted over the whole 2009-10 to 2030-31 time period which accounts for the impact of climate change on projected demand but in a policy environment containing no carbon price signal. This BAU scenario corresponds to the model simulation results underpinning analysis in the previous section. In this section, we will restrict our analysis to the ‘all generation’ case by state.

G.2.2.1 Carbon price impact on carbon emissions by state and fuel-type in 2009-10

Fuel-switching effects associated with production following the introduction of a carbon price of \$23/t$C0_2$ were discussed in Section F.2.2.1. The policy goal underpinning the desire for these effects is to reduced carbon emissions by switching production from technologies with high carbon emission intensity rates to technologies with lower carbon emission intensity rates.

The carbon emission outcomes are listed in Table G-2. The values listed in each panel of Table G-2, for each state and fuel type considered, are the carbon emissions levels associated with the \$0/t$C0_2$ simulation (in the ‘\$0‘ row), and the \$23/t$C0_2$ simulation (in the ‘\$23‘ row). The last row in each panel is the percentage change calculation that, for the values in the ‘\$23’ and ‘\$0’ rows, is calculated as: % Change = [(\$23 - \$0)/\$0]*100.

The impact of the carbon price, for all sources of generation in each state, is listed in Table G-2, Panel (A). It is evident from this table that Victoria experiences the greatest decline in carbon emissions of -8.1 per cent. This is followed by South Australia (-2.3 per cent) and New South Wales (-0.4 per cent). Queensland experiences an increase in carbon emissions of 1.5 per cent. For the NEM, carbon emissions decline by -2.5 per cent. These results broadly match the production trends cited in Table F-3, Panel (A) in Section F.2.2.1.

To investigate the driving forces behind these aggregate outcomes, we investigate the impact of the carbon price by state and by different fuel based generation technologies. In this section, we mirror the approach adopted in the last section and consider coal and gas generation.

The results for coal generation are listed in Table G-2, Panel (B). From assessment of this panel, it is evident that Victoria experiences the largest reduction in carbon emissions from coal generation amounting to a reduction of -8.3 per cent, followed by South Australia (-4.8 per cent), and then New South Wales (-0.5 per cent). Once again, Queensland experiences an increase in carbon emissions from coal generation of 1.5 per cent. For the NEM, carbon emissions from coal generation declines by -2.6 per cent, reflecting primarily the negative contributions of Victoria and South Australia.

It should be noted that the closeness of the results in Panel (B) with those in Panel (A) of Table G-2, indicate the importance of trend carbon emission reductions from coal generation in determining the aggregate state results for Victoria, Queensland and New South Wales. It is also apparent that while the results in Panels (A) and (B) match in qualitative terms, the results in Panel (B) are of a slightly higher magnitude. The aggregate results for South Australia more broadly reflect a combination of trends emerging from both coal and gas generation in that state. Assessment of the last column in Table G-2, Panels (A) and (B) also shows the importance of coal generation in determining, more generally, the aggregate result for the NEM.

Table G-2 (\$23/tC0$_2$) and (\$0/tC0$_2$) carbon emission outcomes by state and fuel type for the 2009-10 benchmark year

Panel (A) all generation

Carbon price	QLD	NSW	VIC	SA	TAS	NEM
\$0	5.38E+07	6.89E+07	6.24E+07	9.33E+06	3.79E+05	1.95E+08
\$23	5.46E+07	6.86E+07	5.73E+07	9.12E+06	3.79E+05	1.90E+08
% Change	1.47	-0.45	-8.13	-2.27	0.00	-2.47

Panel (B) coal generation

Carbon price	QLD	NSW	VIC	SA	NEM
\$0	5.12E+07	6.69E+07	6.14E+07	4.88E+06	1.84E+08
\$23	5.20E+07	6.66E+07	5.63E+07	4.65E+06	1.80E+08
% Change	1.54	-0.47	-8.27	-4.77	-2.62

Panel (C) gas generation

Carbon price	QLD	NSW	VIC	SA	TAS	NEM
\$0	2.60E+06	2.02E+06	1.06E+06	4.45E+06	3.79E+05	1.05E+07
\$23	2.60E+06	2.02E+06	1.06E+06	4.47E+06	3.79E+05	1.05E+07
% Change	0.15	-0.06	0.34	0.47	0.00	0.26

The results for gas generation are outlined in Table G-2, Panel (C). From this panel, it is apparent that South Australia experiences the largest increase in carbon emissions from gas generation of 0.5 of a per cent, followed by Victoria (0.3 of one per cent) and Queensland (0.1 of one per cent). New South Wales experiences a slight decline of -0.1 of a per cent while the position of Tasmania remains unchanged, reflecting the continued dispatch of the NGCC Tamar Valley power station at levels close to its minimum stable operating level.

Another interesting facet of Panel (C) is to clarify the importance of gas generation in the different states in terms of the quantity of carbon emissions generated by this type of generation technology. South Australia is the greatest producer of carbon emissions from gas generation by fair margin, followed by Queensland, New South Wales and Victoria. Thus, the growth experienced in South Australia in carbon emissions is coming off a larger production base associated with gas generation. It should also be noted that a significant proportion of this plant is NGCC or gas thermal generation plant which tend to have lower carbon emission intensity rates than Open Cycle Gas Turbine (OCGT) technologies which are used more for peak load production duties. For the NEM, carbon emissions from gas generation increase by 0.3 of a per cent, reflecting primarily the contribution from South Australia.

G.2.2.2 Carbon price impact over the period 2009-10 to 2030-31

In this section, we examine the consequences of the carbon price when compared against a benchmark simulation conducted over the whole time period 2009-10 to 2030-31. The benchmark simulation accounts for the impact of climate change on projected demand but in a policy environment containing no carbon price signal. The benchmark simulation is the carbon price exclusive \$0/tC0$_2$ simulation while the simulation associated with the carbon price is the carbon price inclusive \$23/tC0$_2$ simulation.

The key metric used in this section is a percentage rate of change calculation conducted on a year-on-year basis over the period 2009-10 to 2030-31 constructed as: % Change = [($23 - $0)/$0]*100. Note that '$23' is the carbon emissions level by state from the carbon price inclusive $23/tC0$_2$ simulation and '$0' denotes the equivalent carbon emissions levels from the carbon price exclusive $0/tC0$_2$ simulation. In this context, the sign associated with the percentage change rates will establish whether the imposition of a carbon price of $23/tC0$_2$ would increase or decrease carbon emissions when compared to the levels obtained from the $0/tC0$_2$ simulation.

The percentage change results in carbon emissions obtained in relation to all sources of generation by state are listed in Table G-3. It is evident from this table that the impact of the carbon price is to increase carbon emissions in Queensland with the positive reinforcement effect increasing slightly over time. For New South Wales, the impact of the carbon price is to reduce the level of carbon emissions relative to the $0/tC0$_2$ levels. The year-on-year effect of this negative reinforcement is quite variable in scope, although in overall terms, there seems to be a tendency for slight magnification of this negative reinforcement effect over the period 2013-14 to 2030-31.

Victoria and South Australia experience similar trends. Specifically, the impact of the carbon price is to reduce carbon emissions further relative to $0/tC0$_2$ levels. However, this negative reinforcement effect diminishes in magnitude over the interval 2013-14 to 2030-31. The results for the NEM also reflect the particular trends identified in the cases of Victoria and South Australia, ignoring a few outliers around 2023-24 and 2024-25.

In the case of Tasmania, apart from some small outliers in 2023-24 and 2024-25, the carbon price does not change carbon emission outcomes from those associated with the $0/tC0$_2$ simulation.

Table G-3 Percentage change between the ($23/tC0$_2$) and ($0/tC0$_2$) carbon emissions outcomes by state and for all sources of generation for the period 2009-10 to 2030-31

Year	QLD	NSW	VIC	SA	TAS	NEM
2009-10	1.47	-0.45	-8.14	-2.27	0.00	-2.47
2010-11	0.46	0.12	-7.90	-2.26	0.00	-2.50
2011-12	0.59	-0.12	-7.14	-2.25	0.00	-2.30
2012-13	0.51	-0.22	-6.81	-1.23	0.00	-2.20
2013-14	0.59	-0.40	-5.64	-1.25	0.00	-1.86
2014-15	0.62	-0.57	-5.22	-1.22	0.00	-1.78
2015-16	0.63	-0.59	-5.00	-1.20	0.00	-1.71
2016-17	0.63	-0.59	-4.96	-1.13	0.00	-1.69
2017-18	0.63	-0.45	-4.68	-1.11	0.00	-1.55
2018-19	0.65	-0.47	-4.61	-1.04	0.00	-1.53
2019-20	0.65	-0.68	-4.19	-0.96	0.00	-1.47
2020-21	0.65	-0.61	-1.46	-0.95	0.00	-0.55
2021-22	0.65	-0.60	-1.44	-0.92	0.00	-0.54
2022-23	0.65	-0.60	-1.44	-0.90	0.00	-0.54
2023-24	0.96	-0.22	-1.09	-0.50	0.28	-0.19
2024-25	0.96	-0.18	-1.06	-0.48	0.29	-0.16
2025-26	0.65	-0.59	-1.15	-0.84	0.00	-0.44
2026-27	0.66	-0.68	-0.94	-0.82	0.00	-0.41
2027-28	0.66	-0.70	-0.90	-0.80	0.00	-0.40
2028-29	0.65	-0.70	-0.88	-0.79	0.00	-0.39
2029-30	0.65	-0.70	-0.86	-0.74	0.00	-0.38
2030-31	0.65	-0.70	-0.86	-0.72	0.00	-0.38

G.2.2.3 Discussion

In summary, the two states experiencing similar outcomes are Victoria and South Australia. The key impact of the carbon price is to reduce carbon emissions obtained relative to those levels associated with the $0/tC0$_2$ simulation. However, over time, this negative reinforcement associated with fuel-switching following the imposition of a $23/tC02 declines in strength ensuring that the size of the reductions in carbon emissions diminish over time. It should be noted that these results are consistent with the use of the CSIRO-Mk3.5 GCM to enumerate the impact of climate change because this GCM produces to most severe impacts of climate change in terms of temperature in Victoria and South Australia. This effect would help to explain why the fuel-switching effect associated with the carbon price diminishes in strength for both states over time as more capacity is needed to meet the growth in demand associated with climate change.

In the case of Queensland, there is growth in carbon emissions relative to $0/tC0$_2$ simulation results, and with this positive reinforcement effects being fairly constant over time, if not having a very slight upward bias. In this context, this outcome is a little different to the results reported in Section F.2.2.3 for the production intensity rate, in which the positive reinforcement effect on production intensity rate tended to diminish over time. Given the production trends outlined in Section F.2.2.3 and reasonably constant year-on-year percentage change results over the period 2013-14 to 2030-31, these results are still consistent with the use of CSIRO-Mk3.5 GCM to quantify the impact of climate change. This follows because this GCM downplays the impact of climate change on temperature in Queensland compared to the other states (except Tasmania).

The state with mixed results is New South Wales. The impact of the carbon price reinforces a decline experienced in carbon emissions under the $0/tC$0_2$ simulation. Moreover, the magnitude of the negative reinforcement effects generally increases over time in the period 2013-14 to 2030-31. These trends match the production intensity rate outcomes shown in Table F-4 in Section F.2.2.2. Therefore, the overall trend effect in New South Wales over time is towards a reduction in carbon emissions in an environment of increasing demand flowing from the impact of climate change. However, once again, a possible explanation of these trends is linked to potential substitution of New South Wales coal generation production located in the Hunter and Central Coast regions of New South Wales by production sourced from Queensland coal and NGCC plant located in the South West Queensland node. See Section F.2.2.3 for a more detailed presentation of this argument. The key implication of this substitution effect argument is it is capable of explaining both the production trends identified in Appendix F and the carbon emission trends arising in Queensland and New South Wales that were identified in this Appendix.

H TRANSMISSION BRANCH UTILISATION AND CONGESTION

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This Appendix outlines the methodology and results from ANEM model simulations based on the projected regional demand profiles for years 2009-10 to 2030-31 to answer the fifth research question:

5. *Comparing the effect of climate change on the transmission congestion between the years 2009-10 and 2030-31 with and without a carbon price.*

In subsequent sections, the methodology used to address this research question will be outlined and the results obtained from ANEM model simulations reported.

H.1 Methodology

The objective of this Appendix is to assess the implications of climate change on transmission branch congestion and utilisation where the main 'transmission' mechanism through which climate change operates is through its impact on electricity demand as addressed in chapter 5.

The ANEM model simulations performed for this investigation utilise projected regional demand profiles based upon the nodal demand equations presented in Sections 5.2 and 5.3. In Section 7.1 and Appendix D, the close correspondence between the results of ANEM model simulations based on actual and projected 2009-10 demand profiles was established for:

- average power flow as a proportion of thermal MW capacity limit on:
  - intra-state transmission lines
  - inter-state interconnectors; and
- proportion of time congested in the year on congested transmission branches.

This outcome allows us to proceed with confidence to use the ANEM model to make comparisons between the years 2009-10 and 2030-31 based on the demand projections for those years relating to transmission branch utilisation and congestion rates.

Section E.2 discusses the general methodology employed to ascertain the key consequences of climate change on the NEM. In this Appendix, we adopt the same methodological approach as outlined in Section E.2 with regard to the choice of 'Business-As-Usual' (BAU) baselines and carbon price settings.

In order to assess the impact of climate change on transmission branch congestion and utilisation, we will be concerned with ANEM simulation outcomes related to power flows on intra-state and inter-state transmission branches. For each state, these transmission

branches are depicted in Appendix B together with the terminal nodes that they connect.
To calculate measures of transmission branch utilisation and congestion, we calculate power flows on transmission lines expressed in terms of average MW power flows. These results were calculated by determining the average MW power flow for each year on each transmission branch and expressing this as a proportion of that transmission branches maximum thermal MW rating. Note that we calculate the absolute value of this proportion to ensure that it has a positive value even when calculated from reverse direction power flows which have negative signs. We also ensure that proper account is taken of the possibility that normal and reverse direction power flows might have different maximum thermal MW limits. We also use the largest maximum thermal MW limit when calculating the proportion values if the values associated with summer and winter thermal limits differ in magnitude. In this case, the largest value will typically correspond to the winter thermal MW limits. This output metric is calculated for all transmission branches including intra-state and inter-state branches.

Branch congestion is defined as arising when the MW power flow on the transmission branch (in either a positive or reverse direction) is equal to the transmission branches rated MW thermal limit, with account also being taken of different limits that might be applicable during winter and summer and by direction of power flows. In the context of this definition and given how average power flows are expressed as a proportion of maximum thermal MW capacity limit, an increase in the proportion values would be indicative of a more utilised transmission network.

In order to quantitatively calculate the degree of branch congestion, we calculate the number of times within all of the dispatch intervals in a year that actual power flows equates with the appropriate MW thermal limit and express this number as a proportion of the total number of dispatch intervals in the year.

In this Appendix, we will restrict attention to transmission branches experiencing congestion and to transmission branches experiencing increased utilisation rates. In this context, recall that we defined this latter concept as occurring when the ratio of average power flow to the transmission branches maximum thermal MW rating increases over time.

H.2 Results

The results associated with the output metrics mentioned above are presented in the next two sections. The first set of results will detail outcomes from carbon price exclusive ($0/tC$0_2$) simulations. This will relate to the impact of climate change on transmission branch utilisation and congestion in the absence of a carbon price. The second set of results reported in the following section will relate to carbon price inclusive ($23/tC$0_2$) simulations in which the carbon price was set to $23/tC$0_2$.

H.2.1 Impact of climate change on transmission branch utilisation and congestion rates for the period 2009-10 to 2030-31 in the absence of a carbon price

The first set of results are reported in Table H-1 and relate to the percentage change in transmission branch utilisation rates over the period 2010-11 to 2030-31 relative to utilisation rates prevailing in 2009-10. It should be note that in order to conserve space, we have only included the more noticeable results and left out those branches experiencing smaller increases in utilisation rates. The results for the inter-state interconnectors are listed in Panel (A) of Table H-1. In this panel, we also provide information about the direction of average power flows over the period 2009-10 to 2030-31. This is recorded in the 'flow' row and a positive sign ('+') indicates average power flows over 2009-10 to 2030-31 in the normal direction. It can be seen from this panel that the average power flows on all interconnectors are in the normal direction. Hence the average power flows represent flows from Queensland to New South Wales on QNI (line 11) and Directlink (line 14). Power also flows on average from New South Wales to Victoria on Tumut-Murray (line 35), Tumut-Dederang (line 36) and Tumut-Regional Victoria (line 37). Power flows on average from Victoria to Tasmania on Basslink (line 42) and from Victoria to South Australia on the Heywood and Murraylink interconnectors (lines 49 and 50). See Appendix B for further details about the location of these transmission lines and connected terminal nodes.

The positive percentage change values listed in Panel (A) indicate increased utilisation over 2010-11 to 2030-31 of transmission lines 11 (QNI), 35 (Tumut-Murray), 36 (Tumut-Dederang), 37 (Tumut-Regional Victoria), 49 (Heywood) and 50 (Murraylink) relative to the 2009-10 utilisation rates. The negative percentage change values associated with Directlink (line 14) and Basslink (line 42) indicates reduced utilisation of these transmission branches over the 2010-11 to 2030-31 period relative to the 2009-10 utilisation rates.

In order to investigate how the utilisation rates might change over time, we have also calculated the percentage change in 2030-31 utilisation rates relative to 2013-14 utilisation rates which are presented in the last row of Panel (A) in the '%Change' row. It follows from inspection of this row that there are reductions of -0.5 of a per cent for QNI, -1.7 per cent for Directlink, -1.1 per cent for Tumut-Murray, -1.0 per cent for Tumut-Dederang, -0.8 of a per cent for Tumut-Regional Victoria, and -0.9 of a per cent for Murraylink. These values can be interpreted as pointing to slight reductions in transmission branch utilisation over the period 2013-14 to 2030-31. Similarly, the increases of 0.1 of a per cent for Basslink and 0.5 of a per cent for Heywood point to a slight increases in utilisation of these transmission branches over the same period of time.

Table H-1 Percentage change in transmission branch utilisation rates relative to 2009-10 for the period 2010-11 to 2030-31

Panel (A) Inter-state interconnectors

Year	line11	line14	line35	line36	line37	line42	line49	line50
Name	QNI	Direct-link	Tum-Mur	Tum-Ded	Tum-RVc	Bass-link	Heywood	Murray-link
flow	+	+	+	+	+	+	+	+
2010-11	7.55	-9.56	0.06	0.06	0.05	0.00	0.20	0.48
2011-12	7.09	-10.85	0.91	0.22	-0.03	0.00	3.36	0.40
2012-13	8.24	-9.12	7.22	6.54	5.63	-0.20	42.61	100.27
2013-14	8.28	-9.06	8.03	7.35	6.21	-0.21	40.82	98.58
2014-15	8.25	-9.11	7.98	7.31	6.18	-0.21	40.86	98.51
2015-16	8.23	-9.17	7.94	7.27	6.15	-0.21	40.90	98.45
2016-17	8.21	-9.23	7.89	7.23	6.12	-0.20	40.94	98.40
2017-18	8.19	-9.29	7.85	7.19	6.09	-0.20	40.97	98.33
2018-19	8.17	-9.35	7.80	7.15	6.06	-0.19	41.01	98.28
2019-20	8.15	-9.40	7.75	7.11	6.03	-0.19	41.04	98.22
2020-21	8.12	-9.46	7.70	7.06	5.99	-0.18	41.05	98.13
2021-22	8.08	-9.57	7.63	7.00	5.94	-0.17	41.15	98.13
2022-23	8.04	-9.68	7.55	6.93	5.88	-0.17	41.20	98.03
2023-24	8.00	-9.79	7.47	6.84	5.81	-0.16	41.34	98.04
2024-25	7.96	-9.90	7.39	6.78	5.76	-0.16	41.43	98.01
2025-26	7.92	-10.02	7.30	6.70	5.71	-0.15	41.47	97.86
2026-27	7.87	-10.14	7.20	6.61	5.64	-0.15	41.51	97.68
2027-28	7.83	-10.27	7.12	6.52	5.56	-0.14	41.65	97.67
2028-29	7.78	-10.40	6.99	6.43	5.50	-0.13	41.52	97.19
2029-30	7.73	-10.52	6.91	6.34	5.42	-0.12	41.67	97.20
2030-31	7.69	-10.65	6.79	6.25	5.35	-0.11	41.55	96.73
%Change	-0.5	-1.7	-1.1	-1.0	-0.8	0.1	0.5	-0.9

Panel (B) Intra-state transmission lines

Year	line3	line10	line15	line16	line17	line34	line38
Name	NQ-CWQ	SWQ-MS	Lis-Arm	Arm-Tam	Tam-Lid	Can-Tum	Mur-Ded
flow	-	+	-	+	+	+	+
2010-11	0.10	23.02	17.81	9.10	10.79	0.04	0.06
2011-12	0.12	23.77	20.24	8.28	9.82	0.54	-0.22
2012-13	8.92	23.60	17.03	10.10	11.99	6.13	6.11
2013-14	8.98	23.58	16.93	10.17	12.06	6.87	6.92
2014-15	9.04	23.62	17.06	10.14	12.02	6.85	6.88
2015-16	9.09	23.65	17.19	10.10	11.97	6.81	6.85
2016-17	9.15	23.68	17.32	10.07	11.93	6.77	6.81
2017-18	9.21	23.72	17.45	10.03	11.88	6.74	6.78
2018-19	9.26	23.75	17.58	10.00	11.84	6.71	6.74
2019-20	9.32	23.78	17.72	9.96	11.79	6.67	6.70
2020-21	9.38	23.82	17.85	9.93	11.75	6.63	6.66

Year	line3	line10	line15	line16	line17	line34	line38
Name	NQ-CWQ	SWQ-MS	Lis-Arm	Arm-Tam	Tam-Lid	Can-Tum	Mur-Ded
flow	-	+	-	+	+	+	+
2021-22	9.48	23.88	18.08	9.86	11.67	6.58	6.59
2022-23	9.58	23.94	18.33	9.80	11.58	6.52	6.54
2023-24	9.68	24.00	18.56	9.73	11.50	6.48	6.45
2024-25	9.78	24.07	18.81	9.66	11.42	6.43	6.39
2025-26	9.89	24.14	19.07	9.60	11.33	6.36	6.32
2026-27	10.01	24.21	19.36	9.52	11.23	6.28	6.25
2027-28	10.12	24.28	19.63	9.44	11.13	6.22	6.14
2028-29	10.24	24.37	19.96	9.36	11.03	6.13	6.08
2029-30	10.36	24.44	20.24	9.28	10.93	6.07	5.98
2030-31	10.48	24.52	20.56	9.20	10.83	5.98	5.91
%Change	1.4	0.8	3.1	-0.9	-1.1	-0.8	-0.9

Panel (C) Intra-state transmission lines (continued)

Year	line39	line43	line51
Name	Ded-Mel	Mor-Haz	SESA-Ehill
flow	+	-	+
2010-11	0.11	0.41	0.17
2011-12	-1.53	0.35	2.31
2012-13	9.09	72.22	40.44
2013-14	10.98	99.92	38.91
2014-15	10.90	99.89	38.89
2015-16	10.84	99.86	38.87
2016-17	10.78	99.83	38.87
2017-18	10.72	99.79	38.85
2018-19	10.65	99.76	38.84
2019-20	10.59	99.73	38.84
2020-21	10.51	99.70	38.81
2021-22	10.37	99.63	38.84
2022-23	10.26	99.58	38.82
2023-24	10.08	99.51	38.89
2024-25	9.97	99.46	38.91
2025-26	9.85	99.41	38.86
2026-27	9.71	99.35	38.82
2027-28	9.48	99.26	38.87
2028-29	9.41	99.22	38.66
2029-30	9.18	99.14	38.69
2030-31	9.08	99.09	38.43
%Change	-1.7	-0.4	-0.3

The results for the intra-state transmission branches experiencing increased utilisation over the period 2010-11 to 2030-31 are reported in Panels (B)-(C) of Table H-1. Recall that direction of flow information for the period 2009-10 to 2030-31 are shown in the 'flow' rows of both panels. It follows from examination of these rows that reverse direction flows are recorded on average for lines 3 (North Queensland-Central West

Queensland), line 15 (Lismore-Armidale) and line 43 (Morwell-Hazelwood). All other lines listed in both Panels (B) and (C) have normal direction flows encompassing flows from South West Queensland-Moreton South (line 10); Armidale-Tamworth (line 16); Tamworth-Liddell (line 17); Canberra-Tumut (line 34); Murray-Dederang (line 38); Dederang-Melbourne (line 39); and South East South Australia-Eastern Hills (line 51).

Because we are only addressing intra-state transmission lines experiencing increased utilisation rates over the period 2010-11 to 2030-31, by definition, all percentage change results are therefore positive in Panels (B) and (C). To investigate how the utilisation rates might change over time, we have once again calculated the percentage change in 2030-31 utilisation rates relative to 2013-14 utilisation rates which are presented in the last row of Panels (B) and (C) in the '%Change' rows. It follows from inspection of these rows that apart from line 15 (Lismore-Armidale) there are reductions in percentage change terms in the utilisation rates experienced for all the intra-state transmission lines that are located in New South Wales, Victoria and South Australia with percentage change values lying in the range -0.3 of a per cent to -1.7 per cent. This situation contrasts with the case of Queensland where percentage increases in utilisation rates occur over the same time period in the range of 0.8 of a per cent to 1.4 per cent.

It should also be noted that when account is taken of the number of inter-state and intra-state transmission branches experiencing increases in utilisation rates relative to 2009-10 rates, this accounts for 60 per cent of all transmission branches included in the ANEM model. Therefore, 40 per cent of all branches included in the ANEM model experience reductions in utilisation rates over the period 2010-11 to 2030-31 relative to the utilisation rates experienced in 2009-10.

Branch congestion results are reported in Table H-2. The results for branch congestion experienced by inter-state interconnectors are listed in Panel (A) while the results for intra-state transmission lines are reported in Panel (B).

Examination of Panel (A) of Table H-2 points to the incidence of congestion on QNI (line 11), Tumut-Regional Victoria (line 37), Basslink (line 42) and Murraylink (line 50). Further assessment indicates that Basslink experiences the most congestion, followed by QNI, then Tumut-Regional Victoria and finally Murraylink. To investigate how the congestion rates change over time, we have calculated the percentage change in 2030-31 congestion rates relative to 2013-14 congestion rates which are presented in the last row of Panel (A) in the '%Change' row. It follows that the degree of transmission branch congestion declines relative to the 2013-14 rates for both QNI (-2.5 per cent) and Tumut-Regional Victoria (-1.5 per cent). In the case of Basslink and Murraylink, the rate of branch congestion has increased marginally over the same period with increases of 0.6 and 0.2 of one per cent recorded for these two interconnectors, respectively.

Table H-2 Proportion of time transmission branches are congested over the period 2009-10 to 2030-31

Panel (A) Inter-state interconnectors

Year	line11	line37	line42	line50
Name	QNI	Tum-RVc	Basslink	Murray-link
2009-10	0.6115	0.2911	0.9969	0.0762
2010-11	0.7392	0.2928	0.9967	0.0763
2011-12	0.7260	0.2908	0.9968	0.0753
2012-13	0.7724	0.3015	0.9841	0.1058
2013-14	0.7746	0.3045	0.9834	0.1047
2014-15	0.7739	0.3039	0.9836	0.1044
2015-16	0.7731	0.3044	0.9840	0.1044
2016-17	0.7717	0.3044	0.9840	0.1043
2017-18	0.7708	0.3046	0.9840	0.1047
2018-19	0.7698	0.3044	0.9845	0.1044
2019-20	0.7692	0.3038	0.9847	0.1041
2020-21	0.7688	0.3034	0.9848	0.1045
2021-22	0.7685	0.3035	0.9857	0.1044
2022-23	0.7667	0.3039	0.9858	0.1040
2023-24	0.7657	0.3024	0.9864	0.1039
2024-25	0.7637	0.3023	0.9865	0.1037
2025-26	0.7613	0.3020	0.9867	0.1039
2026-27	0.7603	0.3008	0.9873	0.1043
2027-28	0.7592	0.3007	0.9880	0.1033
2028-29	0.7583	0.3005	0.9883	0.1034
2029-30	0.7565	0.2990	0.9889	0.1045
2030-31	0.7549	0.2998	0.9893	0.1049
%Change	-2.5	-1.5	0.6	0.2

Panel (B) Intra-state transmission lines

Year	line31	line46
Name	Mur-Yas	Yall-Mel
2009-10	0.0005	0.9991
2010-11	0.0001	0.9991
2011-12	0.0003	0.9991
2012-13	0.0002	1.0000
2013-14	0.0002	1.0000
2014-15	0.0005	1.0000
2015-16	0.0003	1.0000
2016-17	0.0003	1.0000
2017-18	0.0005	1.0000
2018-19	0.0003	1.0000
2019-20	0.0002	1.0000
2020-21	0.0005	1.0000
2021-22	0.0001	1.0000

Year	line31	line46
2022-23	0.0001	1.0000
2023-24	0.0006	1.0000
2024-25	0.0006	1.0000
2025-26	0.0003	1.0000
2026-27	0.0005	1.0000
2027-28	0.0003	1.0000
2028-29	0.0003	1.0000
2029-30	0.0006	1.0000
2030-31	0.0003	1.0000
%Change	50.1	0.0

The branch congestion results for intra-state transmission branches are reported in Panel (B) of Table H-2. As shown in this panel, only two intra-state transmission lines recorded any incidence of branch congestion. These were lines 31 (Marulan-Yass) and line 46 (Yallourn-Melbourne). Of these two particular branches, it is clear from Panel (B) that congestion is a much more serious problem on line 46 than on line 31 with the former experiencing congestion almost all of the time over the period 2009-10 to 2030-31. The last row of Panel (B) also records how the transmission congestion rates change over the period 2013-14 to 2030-31. It is evident that the congestion rates do not vary for line 46 which has 100% congestion over the period 2013-14 to 2030-31. In the case of line 31, there is a sizable percentage increase recorded of 50.1 per cent relative to the 2013-14 congestion rates. However, caution needs to be taken in interpreting this result because it is coming off extremely small congestion rates as indicated in the second column of Panel (B) of Table H-2.

H.2.1.1 Discussion

The implications of average power flows arising on QNI and transmission lines 15-17 provide direct support for the export of power from the South West Queensland node to the Hunter Valley region of New South Wales, via the Armidale, Tamworth and Liddell nodes. Moreover, given the reverse direction power flows that were identified on line 15 (Lismore-Armidale), this also provides supports for the supply of power from South West Queensland going into North Eastern New South Wales via Armidale and Lismore. Thus, these power flows provide direct support for the production substitution effects identified in Appendix F involving the substitution of production from the Hunter Valley - Central Coast regions of New South Wales with production from South West Queensland.

The degree of congestion on the Yallourn-Melbourne branch (line 46) also points to a structural deficiency. The first thing to note is that the Yallourn-Melbourne branch is made up of a number of 220 kV circuits. This can be contrast with most other transmission lines running from the La Trobe Valley to Greater Melbourne which are 500 kV branches and have much greater MW thermal limits than that associated with line 46. Furthermore, the degree of congestion on line 46 would also serve to limit one avenue that generation production from both the La Trobe Valley and even Tasmania has in reaching the Greater Melbourne area.

This congestion also promotes spot price volatility in Victoria with the nodal price associated with the Yallourn node often being negative. This typically arises in situations where the level of demand is insufficient to cover the must run requirements of generation. In this case, this arises because some production from Yallourn becomes 'stranded' because cheaper power from particularly Hazelwood and Loy Yang A power stations flow into the Yallourn node from the Hazelwood node on branch 44 (Hazelwood-Yallourn). When this production is combined with the thermal limits on line 46, it has the effect of limiting Yallourn power station's production intensity rates to around 68% to 69% of its nameplate capacity which is slightly higher than its must run production intensity rate of 60%. In contrast, the production intensity rates of both Hazelwood and Loy Yang A power stations are very close to 100% of their nameplate capacities.

By stranding capacity available to supply the greater Melbourne region, this would mean that more generation, at the margin, would have to be potentially sourced from other more costly forms of generation including gas thermal and OCGT plant located in the Greater Melbourne area or hydro generation located in the Dederang and Murray nodes – see Appendix B for details. This would have the effect of increasing average spot prices in Victoria.

Thus, increasing the MW thermal capacity of line 46 would be expected to reduce spot price levels and spot price volatility in Victoria while also increasing the avenues of potential supply of generation from the La Trobe Valley to the Greater Melbourne Region.

Another structural deficiency surrounds the limited thermal capacity and transfer capabilities on the inter-state interconnectors linking Tumut (New South Wales), Regional Victoria and Riverlands (South Australia). These are the inter-state interconnectors which connect Tumut-Regional Victoria (line 37) and the Murraylink interconnector linking Regional Victoria and South Australia (line 50).

There are a number of concerns with these transmission branches. First they are single 220 kV circuits which curtails there MW thermal capacity limits when compared to 330 kV or 500 kV branches and also makes power flow disruptions particularly vulnerable to line outage events. Power flow on these interconnectors are also dependent upon local 132 kV or 220 kV networks that connect to the major 275kV, 330 kV or 500 kV transmission pathways in South Australia, New South Wales and Victoria. Therefore, to increase the thermal capacity of power transfers on the inter-state interconnectors would also require similar work to be performed on the local transmission networks these interconnectors connect to if enhanced transfer capability is to reach the high voltage transmission networks servicing the major load centres in all three states. In principle, this would entail the need to up-grade the Riverlands (Monash) 132 kV network in South Australia connecting the 275 kV terminal station at Robertstown to the Murraylink terminal station, the regional Victorian 220 kV network connecting to both the Greater Melbourne and Dederang nodes and the transmission infrastructure connecting Darlington Point 330 kV terminal station to Buronga.

These considerations become even more pressing when account is taken of the existing and proposed renewable energy projects located in the Broken Hill area (wind and solar), Regional Victoria (wind) and Mid North South Australia.(wind). This increased capacity will be crucial in facilitating the transfer of excess power particularly associated with wind generation in the Mid North South Australian and Regional Victorian nodes between the three states that will help counter intermittency problems through enhancing system balancing capability through inter-state power transfers.

Finally, the other noticeable congestion point is the Basslink and QNI interconnectors with the findings pointing to the current thermal limits of both interconnectors affecting power transfers from Victoria to Tasmania and Queensland to New South Wales, respectively.

It should be recognised that the NEMLink proposal outlined in AEMO (2011b) would go a long way to meeting the expansion requirements mentioned above. This would particularly apply to renewable energy projects located in the Mid North South Australia and Regional Victorian nodes. This proposal would also facilitate greater scope for power transfers between both Victoria and Tasmania and Queensland and New South Wales which would help alleviate any capacity constraints emerging on the Basslink and QNI Interconnectors. The particular focus of this proposal appears to be on providing high transmission infrastructure linkages to the location of existing wind farm sites in South Australia, Victoria and New South Wales and expected future developments in gas generation linked to coal seam gas reserves in South West Queensland. This proposal, however, in its current form, is not so well placed to meet any widespread development of renewable energy projects in newly emerging areas such as Broken Hill, Upper North South Australia or the western reaches of the Otway Basin, for example.

H.2.2 Impact of climate change on transmission branch utilisation and congestion for the period 2009-10 to 2030-31 in the presence of a carbon price of \$23/tC0$_2$

In this section, we assess the impact of a carbon price of \$23/tC0$_2$ on transmission branch utilisation and congestion rates determined from ANEM model simulations. We will examine the consequences of the carbon price when compared against a benchmark simulation conducted over the whole 2009-10 to 2030-31 time period which accounts for the impact of climate change on projected demand but in a policy environment containing no carbon price signal. The benchmark simulation is the carbon price exclusive \$0/tC0$_2$ simulation while the simulation associated with the carbon price is the carbon price inclusive \$23/tC0$_2$ simulation.

In the analysis in this section, we mainly focus attention on the impact that the carbon price has on utilisation and congestion outcomes related to the transmission lines already identified in Section H.2.1. The key metric used in this section is a percentage rate of change conducted on a year-on-year basis over the period 2009-10 to 2030-31 constructed as: % Change = [(\$23 - \$0)/\$0]*100. Note that '\$23' is the transmission branch utilisation and congestion rates from the carbon price inclusive \$23/tC0$_2$ simulation whereas '\$0' denotes the equivalent rates from the carbon price exclusive \$0/tC0$_2$ simulation. The sign associated with the percentage change calculation will establish whether the imposition of a carbon price of $23/t$CO_2$ would increase or decrease the transmission branch utilisation and congestion rates when compared to the rates obtained from the $0/t$CO_2$ simulation.

The percentage change results associated with transmission branch utilisation rates are listed in Table H-3. Panel (A) contains the results for the inter-state interconnectors while Panels (B)-(C) contain the results for the same set of intra-state transmission lines that were listed in Panels (B)-(C) of Table H-1 in Section H.2.1.

It is evident from Panel (A) that for all inter-state interconnectors except Basslink, the carbon price positively reinforces the utilisation rates associated with the carbon price exclusive $0/t$CO_2$ simulation. This means that the carbon price increases the utilisation rates of these transmission branches when compared to the utilisation rates associated with the carbon price exclusive $0/t$CO_2$ simulation. Furthermore, for these transmission branches, it is also apparent that the reinforcement effects generally diminishes over the period 2013-14 to 2030-31 except in the case of Directlink (line 14) which experiences a slight increase in reinforcement over this same time period. It is also noticeable that over the period 2013-14 to 2030-31, the positive reinforcement effects alluded to above decline the most for lines 35 (Tumut-Murray), line 36 (Tumut-Dederang) and line 37 (Tumut-Regional Victoria), followed (with significantly reduced magnitudes) by Murraylink and Heywood. The rate of decline is of a much lower order of magnitude for QNI when compared to the other transmission branches mentioned above.

In the case of Basslink, the effect of the carbon price is to negatively reinforce the utilisation rates obtained from the carbon price exclusive $0/t$CO_2$ simulation. This means that the carbon price reduces the utilisation rate of Basslink when compared to the utilisation rates obtained from the carbon price exclusive $0/t$CO_2$ simulation. The negative reinforcement effect, however, also diminishes markedly over the time period 2013-14 to 2030-31 and particularly so from 2020-21.

Table H-3 Percentage change between the ($23/t$CO_2$) and ($0/tCO_2) transmission branch utilisation rate outcomes for the period 2009-10 to 2030-31

Panel (A) Inter-state interconnectors

Year	line11	line14	line35	line36	line37	Line42	line49	line50
Name	QNI	Directlink	Tum-Mur	Tum-Ded	Tum-RVc	Basslink	Heywood	Murraylk
2009-10	9.08	18.18	10.84	10.82	8.28	-51.32	4.45	28.18
2010-11	4.38	8.37	10.10	10.09	7.73	-50.52	4.66	27.33
2011-12	4.74	9.79	8.17	8.22	6.35	-46.50	5.16	25.60
2012-13	3.75	7.95	5.12	5.23	4.16	-49.81	7.76	13.19
2013-14	3.69	8.42	3.30	3.42	2.80	-42.62	8.60	12.70
2014-15	3.69	8.66	1.71	1.84	1.59	-41.65	8.82	11.63
2015-16	3.69	8.64	1.54	1.66	1.46	-39.70	8.64	11.33
2016-17	3.69	8.64	1.46	1.59	1.39	-39.27	8.19	10.72
2017-18	3.67	8.62	2.66	2.77	2.28	-33.65	7.56	11.06
2018-19	3.74	8.79	2.61	2.72	2.23	-32.98	7.11	10.47
2019-20	3.72	8.76	0.80	0.92	0.86	-32.67	7.26	9.04

Year	line11	line14	line35	line36	line37	Line42	line49	line50
Name	QNI	Directlink	Tum-Mur	Tum-Ded	Tum-RVc	Basslink	Heywood	Murraylk
2020-21	3.70	8.71	1.35	1.46	1.27	-5.67	6.90	9.13
2021-22	3.70	8.73	1.37	1.49	1.29	-5.36	6.59	8.81
2022-23	3.71	8.78	1.38	1.48	1.27	-5.23	6.48	8.72
2023-24	3.65	8.63	1.80	1.90	1.58	-3.63	6.14	8.71
2024-25	3.67	8.68	2.09	2.19	1.80	-2.67	5.81	8.59
2025-26	3.69	8.74	1.43	1.54	1.31	-2.22	5.77	8.01
2026-27	3.71	8.80	0.58	0.68	0.65	-2.02	5.85	7.41
2027-28	3.73	8.85	0.39	0.50	0.52	-1.88	5.63	7.04
2028-29	3.69	8.79	0.36	0.45	0.47	-1.79	5.59	7.02
2029-30	3.66	8.72	0.30	0.42	0.44	-1.54	5.11	6.41
2030-31	3.66	8.76	0.32	0.42	0.43	-1.38	4.89	6.21

Panel (B) Intra-state transmission lines

Year	line3	line10	line15	line16	line17	line34	line38
2009-10	0.03	-6.52	-33.86	15.07	17.89	9.69	10.80
2010-11	0.03	-1.01	-11.98	6.93	8.10	9.02	10.08
2011-12	0.06	-1.61	-13.52	7.59	8.88	7.28	8.25
2012-13	0.00	-1.52	-11.50	6.00	7.00	4.59	5.31
2013-14	0.00	-2.00	-12.21	5.98	6.98	2.93	3.50
2014-15	0.00	-2.19	-12.52	6.01	7.01	1.47	1.91
2015-16	0.00	-2.18	-12.47	6.00	7.00	1.31	1.74
2016-17	0.00	-2.18	-12.46	6.00	7.00	1.26	1.66
2017-18	0.00	-2.17	-12.40	5.98	6.98	2.36	2.85
2018-19	0.00	-2.22	-12.63	6.09	7.11	2.30	2.79
2019-20	-0.01	-2.22	-12.56	6.06	7.08	0.65	0.99
2020-21	-0.01	-2.21	-12.47	6.02	7.03	1.15	1.53
2021-22	0.00	-2.22	-12.45	6.03	7.04	1.18	1.56
2022-23	-0.01	-2.23	-12.48	6.05	7.07	1.20	1.55
2023-24	-0.01	-2.18	-12.23	5.95	6.95	1.56	1.96
2024-25	-0.01	-2.19	-12.26	5.98	6.99	1.84	2.25
2025-26	0.00	-2.20	-12.29	6.01	7.03	1.24	1.62
2026-27	-0.01	-2.21	-12.34	6.06	7.08	0.44	0.75
2027-28	0.00	-2.22	-12.36	6.08	7.11	0.30	0.57
2028-29	-0.01	-2.21	-12.24	6.03	7.05	0.26	0.51
2029-30	0.00	-2.20	-12.08	5.97	6.98	0.20	0.49
2030-31	-0.01	-2.21	-12.09	5.98	7.00	0.22	0.48

Panel (C) Intra-state transmission lines (continued)

Year	line39	line43	line51
2009-10	23.17	15.65	4.18
2010-11	21.55	15.03	4.35
2011-12	17.79	14.86	4.46
2012-13	10.65	2.15	6.45
2013-14	6.69	-0.18	6.96

Year	line39	line43	line51
2014-15	3.33	-0.19	6.95
2015-16	2.98	-0.19	6.84
2016-17	2.85	-0.18	6.44
2017-18	5.39	-0.18	6.17
2018-19	5.31	-0.19	5.77
2019-20	1.51	-0.19	5.57
2020-21	2.68	-0.18	5.40
2021-22	2.78	-0.18	5.17
2022-23	2.74	-0.17	5.11
2023-24	3.64	-0.17	4.91
2024-25	4.28	-0.16	4.68
2025-26	2.95	-0.16	4.56
2026-27	1.09	-0.15	4.51
2027-28	0.75	-0.14	4.33
2028-29	0.58	-0.14	4.34
2029-30	0.60	-0.12	3.92
2030-31	0.60	-0.12	3.79

The percentage change in transmission branch utilisation rates associated with the impact of the carbon price on intra-state transmission branches are displayed in Panels (B) and (C) of Table H-3. It follows from assessment of these two panels that line 3 (North Queensland-Central West Queensland), line 10 (South West Queensland–Moreton South) and line 15 (Lismore-Armidale) experience negative reinforcement effects associated with the imposition of the carbon price of $23/tC0$_2$. Recall that this negative reinforcement means that the carbon price reduces the utilisation rates of these transmission branches when compared to the utilisation rates associated with the carbon price exclusive $0/tC0$_2$ simulation. Note also that the magnitude of this negative reinforcement increases in the case of line 10 while diminishing slightly in the case of line 15. In the case of line 3, the impact of the carbon price is very marginal, producing very small percentage differences from the price exclusive $0/tC0$_2$ simulation results.

All other lines listed in Panels (B)-(C) experience positive reinforcement effects. Recall that positive reinforcement means that the carbon price increases the utilisation rates of these transmission branches when compared to the utilisation rates associated with the carbon price exclusive $0/tC0$_2$ simulation. It is also apparent that the positive reinforcement generally diminishes in magnitude over the period 2013-14 to 2030-31 except for the case of line 17 (Tamworth-Liddell) which experiences a slight increase in positive reinforcement over this same time period. Of those transmission branches experiencing declining positive reinforcement, line 34 (Canberra-Tumut), line 38 (Murray-Dederang) and line 39 (Dederang-Melbourne) experience the greatest rates of decline in positive reinforcement. These transmission branches are then followed by line 51 (South East South Australia-Eastern Hills) although the magnitude of decline is at a significantly reduced magnitude when compared with the former three transmission branches.

Transmission branch 43 (Morwell to Hazelwood) displays a lot more variability with positive but declining reinforcement occurring over the period 2009-10 to 2012-13 followed by negative reinforcement at smaller magnitudes over the period 2013-14 to 2030-31. This is linked to the de-commissioning of Energy Brix power station over the period 2012-13 to 2013-14. Under a carbon price of $23/tC0_2$, power transfers still continues to increase over the period 2012-13 to 2013-14 from the Hazelwood to Morwell nodes to meet the supply shortfall associated with the de-commissioning of Energy Brix. However, compared to the carbon price exclusive $0/tC0_2$ simulation results, the carbon price has markedly eroded the competitive position of brown coal generation production coming from the Hazelwood node relative to gas plant located at the Morwell node. As such, and relative to the $0/tC0_2$ simulation results, there is some partial substitution of output from Hazelwood by gas plant located at Morwell – especially Bairnsdale power station. Therefore less power flows from Hazelwood to Morwell node under a carbon price of $23/tC0_2$, relative to the $0/tC0_2$ simulation results, thereby producing the negative reinforcement observed in Panel (C) over the period 2013-14 to 2030-31.

The introduction of a carbon price signal can potentially cause both intra-state and inter-state dispatch patterns to change significantly from some BAU benchmark. This would potentially show up in terms of both changes in *magnitude* and *direction* of average power flows on the inter-state and intra-state transmission branches. It is also possible that transmission branch utilisation rate characteristics might change over what was observed in the BAU carbon price exclusive $0/tC0_2$ simulations. Given our focus is on investigating which branches experience increasing branch utilisation rates over time, we found that the utilisation characteristics of some transmission branches did change with the imposition of the carbon price of $23/tC0_2$. For completeness, these branches are listed in Table H-4.

The signs of the average power flows listed in the 'flow' row of Table H-4 indicate that, on average, power flows from Liddell to Bayswater (line 18); from Marulan to Wollongong (line 29); from Melbourne to Regional Victoria (line 48), and from George Town to Sheffield (line 58).

To investigate how the utilisation rates might change over time, we have also calculated the percentage change in 2030-31 utilisation rates relative to 2013-14 rates which are presented in the last row of Table H-4 in the '%Change' rows. It follows from inspection of this row that apart from line 29 (Wollongong-Marulan), there are increases in percentage change terms in the utilisation rates experienced for all the intra-state transmission lines listed in Table H-4 relative to the 2013-14 utilisation rates. These percentage change values lie in the range of 0.5 of a per cent to 28.3 per cent. In the case of line 29, the result is more of an artefact of the rates coinciding for 2013-14 and 2030-31. In overall terms, however, for this branch there is probably a downward bias when account is taken of the number of times the percentage change values over the period 2013-14 to 2030-31 are less than the 2013-14 and 2030-31 values cited in Table H-4.

Table H-4 Percentage change in transmission branch utilisation rates relative to 2009-10 for the period 2010-11 to 2030-31 for a carbon price of $\$23/tC0_2$: additional transmission lines

Year	line18	line29	line48	line58
Name	Lid-Bayw	Woll-Mar	Mel-RegV	GrT_Shef
flow	+	-	+	+
2010-11	3.08	9.17	0.87	0.47
2011-12	4.14	31.93	3.96	2.68
2012-13	5.36	53.31	7.25	-0.86
2013-14	6.37	65.09	8.44	4.04
2014-15	6.95	80.92	10.56	4.82
2015-16	7.25	80.30	10.78	6.21
2016-17	7.51	77.79	10.82	6.52
2017-18	6.89	52.07	9.20	10.40
2018-19	6.84	49.41	9.21	10.94
2019-20	4.40	78.70	11.58	11.26
2020-21	5.27	64.52	10.84	29.71
2021-22	5.46	60.44	10.81	30.04
2022-23	5.58	57.05	10.85	30.22
2023-24	5.61	47.31	10.34	31.39
2024-25	5.76	39.29	9.95	32.11
2025-26	6.38	48.57	10.82	32.47
2026-27	6.99	62.84	12.00	32.69
2027-28	7.13	64.31	12.29	32.89
2028-29	7.05	64.97	12.39	33.02
2029-30	6.96	65.32	12.42	33.28
2030-31	6.94	65.14	12.41	33.44
%Change	0.5	0.0	3.7	28.3

It should be noted that when account is taken of the number of inter-state and intra-state transmission branches experiencing increases in utilisation rates relative to 2009-10 rates, this now accounts for only 39 per cent of all transmission branches included in the ANEM model. Therefore, 61 per cent of all branches included in the ANEM model now experience reductions in utilisation rates over the period 2010-11 to 2030-31 relative to the utilisation rates experienced in 2009-10. This is a noticeable change on the results reported in Section H.2.1. Overall, the impact of the carbon price seems to be to promote a trend towards reduced utilisation on transmission branches.

Branch congestion results are reported in Table H-5. The results for congestion experienced by inter-state interconnectors are listed in Panel (A) while the results for intra-state transmission lines are reported in Panel (B). It should be noted that no additional congested lines emerged following the imposition of a carbon price of $\$23/tC0_2$ over those transmission branches already experiencing branch congestion that were identified in Section H.2.1.

Recall that we are restricting attention to those inter-state interconnectors identified in Section H.2.1 as experiencing branch congestion. These transmission branches were QNI (line 11), Tumut-Regional Victoria (line 37), Basslink (line 42) and Murraylink (line 50). The results reported in Table H-5 are the percentage change in branch congestion rates relative to the rates associated with the carbon price exclusive $0/tC0$_2$ simulation results. Thus the sign on values in the table will indicate whether the imposition of a $23/tC0$_2$ carbon price alleviated or increases the incidence of branch congestion on these inter-state interconnectors. Positive signed values would indicate positive reinforcement associated with the carbon price and an increased incidence of branch congestion.

It is apparent from inspection of Panel (A) that QNI (line 11), Tumut-Regional Victoria (line 37) and Murraylink (line 50) experience increased branch congestion associated with the carbon price over and above the rates of branch congestion produced by the BAU $0/tC0$_2$ simulation. In the case of both QNI and Murraylink, the magnitude of positive reinforcement diminishes over the 2013-14 to 2030-31 time period while in the case of line 37 (Tumut-Regional Victoria), the extent of positive reinforcement strengthens over the same time period. In the case of Basslink (line 42), the carbon price produces negative reinforcement that also diminishes over the time period 2013-14 to 2030-31. Thus, on Basslink, the results shown in Panel (A) indicate lower congestion rates associated with the carbon price but with this reduction in branch congestion diminishing in magnitude over the period 2013-14 to 2030-31.

Table H-5 Percentage change between the ($23/tC0$_2$) and ($0/tC0$_2$) branch congestion outcomes for the period 2010-11 to 2030-31

Panel (A) Inter-state interconnectors

Year	line11	line37	line42	line50
Name	QNI	Tum-RVc	Basslink	Murraylk
2009-10	33.56	15.62	-99.11	10.50
2010-11	29.50	10.18	-99.09	10.03
2011-12	30.62	5.50	-98.07	9.26
2012-13	23.92	3.33	-97.92	8.42
2013-14	23.44	3.23	-96.54	7.42
2014-15	23.50	3.87	-96.10	6.90
2015-16	23.33	4.62	-95.17	6.23
2016-17	23.45	4.66	-94.87	5.58
2017-18	23.39	4.65	-90.53	5.24
2018-19	24.35	4.88	-88.51	3.73
2019-20	24.09	5.00	-87.26	3.73
2020-21	23.96	5.27	-18.14	3.49
2021-22	23.82	5.00	-17.49	3.60
2022-23	23.98	4.55	-17.25	3.85
2023-24	22.89	4.84	-11.94	4.40
2024-25	23.12	5.07	-8.06	4.62
2025-26	23.30	5.59	-5.71	4.39
2026-27	23.43	5.85	-5.24	4.93

Year	line11	line37	line42	line50
Name	QNI	Tum-RVc	Basslink	Murraylk
2027-28	23.35	5.54	-5.25	5.96
2028-29	22.87	5.64	-5.25	5.53
2029-30	22.91	5.76	-3.91	4.81
2030-31	23.12	5.68	-3.37	4.79

Panel (B) Intra-state transmission lines

Year	line31	Line46
2009-10	-50.00	-8.44
2010-11	99.99	-7.31
2011-12	0.00	-3.44
2012-13	50.00	-1.15
2013-14	50.00	-0.31
2014-15	-50.00	-0.06
2015-16	-33.33	-0.05
2016-17	-33.33	-0.03
2017-18	0.00	-0.01
2018-19	0.00	-1.35
2019-20	50.00	-2.14
2020-21	-50.00	-2.16
2021-22	299.96	-0.96
2022-23	300.00	-0.05
2023-24	-20.00	-0.01
2024-25	-20.00	0.00
2025-26	-0.01	0.00
2026-27	-50.00	0.00
2027-28	33.32	0.00
2028-29	0.01	0.00
2029-30	-0.01	0.00
2030-31	0.00	0.00

The branch congestion results for intra-state transmission branches are reported in Panel (B) of Table H-5. As identified in Section H.2.1, only two intra-state transmission lines recorded any incidence of branch congestion. These were lines 31 (Marulan to Yass) and line 46 (Yallourn to Melbourne). The sign of the percentage change results listed in Panel (B) for line 31 is quite variable in terms of both magnitude and sign. However, care must be exercised in interpreting these values because they are coming off very small congestion rates for both the \$23/tC0$_2$ and \$0/tC0$_2$ simulations.

Congestion is much more significant on line 46 (Yallourn to Melbourne) although the carbon price appears to marginally relieve this pressure especially over the years 2009-10 to 2012-13. Moreover, for the period 2009-10 to 2023-24, the effect of the carbon price is one of negative reinforcement, thus relieving congestion, although generally at a diminishing rate. After 2023-24, the carbon price has no discernible impact on congestion relative to the rates associated with the \$0/tC0$_2$ simulation.

Therefore, from 2024-25 onwards, the congestion rates associated with both the \$23/tC0_2 and \$0/tC0_2 simulations coincide.

H.2.2.1 Discussion

The imposition of a carbon price seems to affect power flows on the Basslink interconnector to a greater extent when compared to the other inter-state interconnectors. The sizable percentage declines in both utilisation and congestion rates over the period 2009-10 to 2019-20 reflect increase supply of power into the George Town and Sheffield nodes from Poatina power station in particular. This reduces power transfers from George Town to Sheffield and from Loy Yang to George Town on Basslink. However, over time, the power supply from Poatina to both George Town and Sheffield nodes begins to decline towards its BAU \$0/tC02 simulation levels and power transfers on Basslink begin to ramp back up towards their BAU \$0/tC02 simulation levels. This is responsible for the reduction in negative reinforcement observed in Tables H-3 and H-5, Panels (A), by 2030-31.

The other noticeable impact of the carbon price is for Murraylink to experiences sizable increases in utilisation and congestion rates over the period 2009-10 to 2012-13, in particular. The greater average power flows on Murraylink over this time period reflects greater average power flow on line 37 (Tumut-Regional Victoria) and line 40 (Dederang-Regional Victoria). This would reflect, in turn, the improvement in the competitive position of hydro generation in the Tumut and Dederang nodes relative to competing thermal plant in an environment containing a carbon price of \$23/tC0_2. Note also that the slight reduction in positive reinforcement seen over the 2013-14 to 2030-31 period on Murraylink principally reflects the impact of a decline in positive reinforcement experienced over time on line 37 more so than on line 40.

More generally, the impact of the carbon price, irrespective of whether it promotes positive or negative reinforcement relative to the BAU (\$0tC0_2) simulation outcomes, typically diminishes over the time interval 2013-14 to 2030-31. This means that over time, the results from the carbon price inclusive (\$23/tC0_2) simulation tends to approach the results associated with the carbon price exclusive (\$0/tC0_2) simulation. While there are always some exceptions to this rule such as for Directlink and Tamworth-Liddell identified above, in overall terms, the above trend typically arises in most cases.

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