2011

SOUTH AUSTRALIAN SUPPLY AND DEMAND OUTLOOK

Published by

AEMO
Australian Energy Market Operator Limited
ABN 94 072 010 327
ISSN 1839-1729

530 Collins Street
Melbourne Victoria 3000

[This page is left blank intentionally]

DISCLAIMER

This publication has been prepared by the Australian Energy Market Operator Limited (AEMO) using information available at 31 March 2011, unless otherwise specified. AEMO must publish the South Australian Supply and Demand Outlook in order to comply with Section 50B of the National Electricity Law.

The purpose of publication is to provide information to participants and the minister of an adoptive jurisdiction about matters relevant to the future capacity and reliability of the adoptive jurisdiction's declared power system.

Some information available after 31 March 2011 might have been included in this publication where it has been practicable to do so.

Information in this publication does not amount to a recommendation in respect of any possible investment and does not purport to contain all of the information that a prospective investor or participant or potential participant in the South Australian electricity market might require. The information contained in this publication might not be appropriate for all persons and it is not possible for AEMO to have regard to the investment objectives, financial situation, and particular needs of each person who reads or uses this publication. The information contained in this publication may contain errors or omissions, or might not prove to be correct.

In all cases, anyone proposing to rely on or use the information in this publication should independently verify and check the accuracy, completeness, reliability, and suitability of that information (including information and reports provided by third parties) and should obtain independent and specific advice from appropriate experts.

Accordingly, to the maximum extent permitted by law, neither AEMO, nor any of AEMO's advisers, consultants or other contributors to this publication (or their respective associated companies, businesses, partners, directors, officers or employees):

a) make any representation or warranty, express or implied, as to the currency, accuracy, reliability or completeness of this publication and the information contained in it, and

b) shall have any liability (whether arising from negligence, negligent misstatement, or otherwise) for any statements, opinions, information or matter (expressed or implied) arising out of, contain in or derived from, or for any omission from, the information in this publication, or in respect of a person's use of the information (including any reliance on its currency, accuracy, reliability or completeness) contained in this publication.

Acknowledgement

AEMO acknowledges the support, co-operation, and contribution of all participants in providing the data and information used in this publication.

[This page is left blank intentionally]

KEY FINDINGS

The South Australian Annual Supply and Demand Outlook (SASDO) is an independent report prepared by the Australian Energy Market Operator (AEMO) about the current state and future development of South Australian electricity supply. The 2011 SASDO provides information about the following key areas at the request of the South Australian Government:

- Historical and forecast energy and maximum demand.
- Estimated greenhouse gas emissions for South Australian electricity usage options.
- Generation forecasts, including existing and potential future electricity supply options.
- Electricity generation, historical fuel use and a future electricity generation fuel availability assessment.
- Significant future fossil fuel generation projects.
- Significant renewable energy generation projects.
- Historical generation for South Australian generators.

Demand considerations

Maximum demand for the 2010/11 summer

South Australia experienced a mild summer with only a few days exceeding 40 °C. A relatively short heat wave occurred in late January 2011.

The maximum demand for the year was 3,433 MW, and occurred at 4:30 PM (Australian Eastern Standard Time) on 31 January 2011 (at a temperature of 42.9 °C). A higher maximum might have been expected if the same conditions had occurred later in the week, after an extended hot weather period.

Background and assumptions for the forecasts

South Australian demand growth is correlated with both the gross domestic product (GDP) and gross state product (GSP).

Population growth in South Australia remains below the national average, although the growth rate in recent years has increased as a result of increased net interstate migration.

Electricity demand from housing construction is expected to rise in 2010/11 in line with recent population growth and the services sector is expected to mirror that in the wider national economy.

Under a low economic growth scenario, forecasts of GSP reflect weaker business investment due to higher risk premiums, as well as softer housing investment and a relatively poor trade performance.

Under the high economic growth scenario, strong population growth supports fast-paced growth in housing investment, while a lower risk premium facilitates greater business investment.

Major projects contributing to electricity demand

The historically high level of infrastructure spending in South Australia is expected to drive medium-term GSP growth.[1]

Mining output is forecast to grow at 5.1% annually over the short term, reflecting expected growth in output from the Olympic Dam Mine and the Olympic Dam Mine expansion project (which has proceeded to the feasibility stage).[2]

[1] The South Australian Government has $71.5 billion worth of major projects either planned or underway, including the Port Stanvac desalination plant and the metropolitan train network electrification.

[2] This project is only considered under a high economic growth scenario.

The proposed construction of a pulp mill at Penola may create significant demand in the south east, although the size and timing of this proposal is currently being revised.[3]

Demand from the new Port Stanvac desalination plant, which is expected to commence operation by the end of 2012, is assumed to have a capacity of 100 gigalitres per annum.

Carbon price assumptions

Average retail electricity prices are a driver of electricity sales and peak demand levels in South Australia. The price elasticity of electricity demand is assessed as part of the South Australian load forecasting analysis performed for AEMO by Monash University. The annual price elasticity of electricity demand is estimated to be -0.25, with slightly less than half this applying to peak demand (that is, a 4% real rise in prices is expected to lead to a 1% reduction in sales and a 0.5% reduction in peak demands).

The electricity demand forecasts in this document were prepared using the assumption that the Australian Government would introduce a carbon price of 10 \$/t CO2-e in 2013/14, before implementing the full emissions trading scheme in 2014/15. The 10 \$/t CO2-e in 2013/14 price assumption was developed by AEMO in 2009 for the 2010 National Transmission Network Development Plan (NTNDP) scenarios, in consultation with industry stakeholders. The carbon prices assumed from 2014/15 onwards reflect the latest (2008) Australian Government Treasury modelling related to the potential economic impacts of reducing emissions over the medium and long term.[4] The carbon price under each scenario is assumed to grow at a real rate of 4% per annum from 2014/15 onwards, reflecting the fact that carbon permits are financial assets and are bankable over time.

After the scenarios were developed, the government announced its plan to introduce a fixed carbon price from 1 July 2012, followed by a transition to emissions trading within three to five years. This change does not affect the long-term carbon price projections in the scenarios. The different start dates and starting prices will have only a short-term impact, as the longer-term carbon emissions reductions targets for each scenario are assumed to be unchanged. Since the forecast long-term carbon price trajectory is substantially unchanged, there is no material effect on the macro-economic parameters, and only a small impact on the overall long-term trend in electricity prices. Consequently the energy and maximum demand forecasts presented in the 2011 SASDO remain valid. Once emissions trading is introduced the carbon price will be determined by the market, taking into account the level of reduction required and the costs of providing it, as modelled for each scenario.

Maximum demand forecast

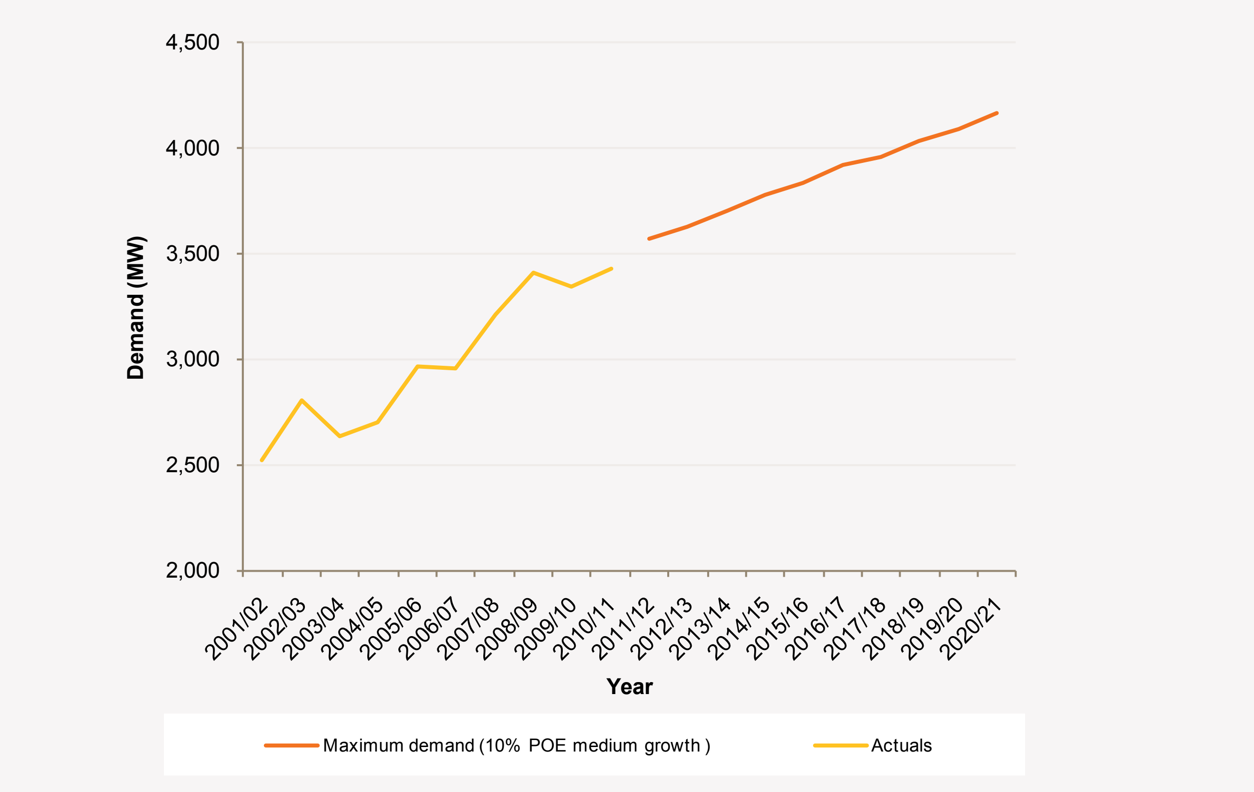
The 10% probability of exceedence (POE) medium growth summer maximum demand is forecast to rise from 3,570 MW in 2011/12, at an average of 1.9% per annum over the next 10 years, reaching 4,170 MW by 2020/21.

Figure 1 shows the growth in the maximum demand.

[3] This project is only considered under a high economic growth scenario, however, recent announcements regarding this project indicate that it is now in liquidation (www.adelaidenow.com.au/business/penola-pulp-mill-plans-dead/story-e6frede3-1226075169327).

[4] Commonwealth of Australia, “Australia’s Low Pollution Future: The Economics of Climate Change Mitigation”. 2008.

Figure 1 — Maximum electricity demand



Energy forecasts

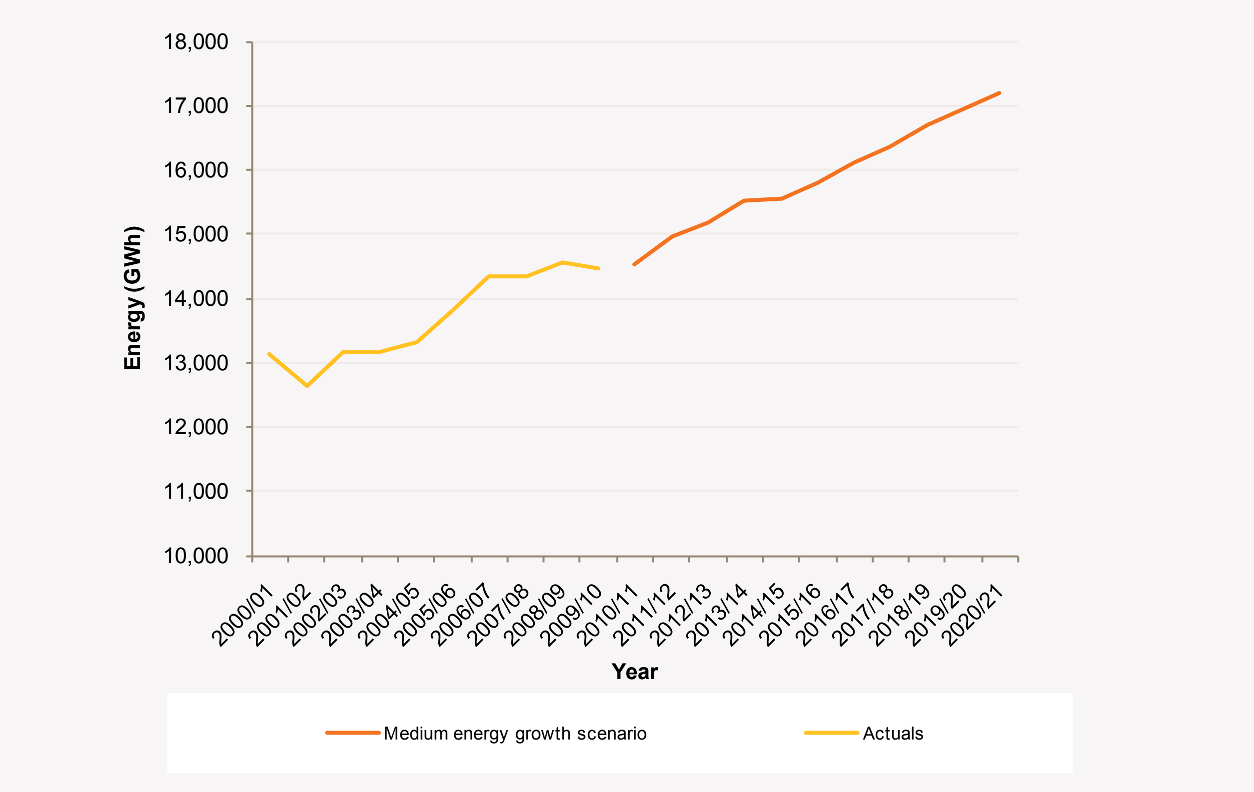
Energy growth is forecast to rise by an average of 1.7% per annum over the next 10 years, reaching 17,195 GWh by 2020/21.

Annual growth of customer sales is projected to average 1.56% under the medium economic growth scenario.

Major loads include Port Stanvac desalination plant and the Olympic Dam mine.

Figure 2 shows the growth in energy.

Figure 2 — Electrical energy growth



Supply considerations

Table 1 summarises South Australia's generation capacity.

Table 1 — South Australian generation

Generation type[d]	Nameplate rating (MW)[a]	Summer 2011/12 (MW)	Winter 2012 (MW)
Scheduled thermal generation	3,686.8	3,414.0	3,599.0
Scheduled/semi-scheduled wind generation	762.6[b]	Available 485 Firm 40.8	Available 815.1 Firm 28.5
Total scheduled/(firm) semi-scheduled generation	-	3,455.8	3,627.5

a. While nameplate ratings indicate plant capacity, the actual level of generation available at any particular time depends on the age of the plant, outages, wear, and ambient temperatures.

b. There is currently 762.6 MW of wind generation, which will increase to 815.1 MW by the end of 2011.

c. A full supply demand balance will be provided in the 2011 Electricity Statement of Opportunities to be published on 31 August 2011.

d. See the glossary or Chapter 3 for definitions of scheduled and semi-scheduled dispatch.

Changes in supply since 2010

Changes in generation capacity since the 2010 SASDO include the following projects:

- TRUenergy completed construction of a 27.5 MW unit at the Hallett Gas Turbine Power Station in the mid-north, increasing the plant's capacity to 228.3 MW.
- Synergen/International Power completed construction of a 23.5 MW unit at Port Lincoln at the bottom of the Eyre Peninsula on the west Coast, increasing the plant's capacity to 73.5 MW.
- Infigen Energy/Lake Bonney Wind Power completed the 39 MW Lake Bonney Stage 3 Wind Farm in the south east.
- Roaring 40s completed the 111 MW Waterloo Wind Farm in the mid-north.
- AGL Energy/Brown Hill North completed the 132.3 MW Hallett Stage 4–North Brown Hill Wind Farm.

One new wind farm is currently under construction, with AGL Power Generation having commenced construction of the 52.5 MW Hallett Stage 5 – The Bluff Wind Farm. Completion is expected by December 2011.

Wind generation

The capacity of wind generation in South Australia continues to grow. Wind energy has now reached 20% of energy production.[5] There is 1,150 MW of installed wind generation capacity (increasing to approximately 1,203 MW with the completion of Hallett Stage 5).

Wind contributed only 60 MW during the summer 2011 maximum demand, which occurred at 4:30 PM (Australian Eastern Standard Time) on 31 January 2011. However, at times during the week either side of the maximum demand, that output reached 873 MW.

The methodology for calculating the expected wind farm contribution during peak demand has been revised, with the summer and winter peak contribution now anticipated to be 5% and 3.5% (respectively) of their installed capacities.

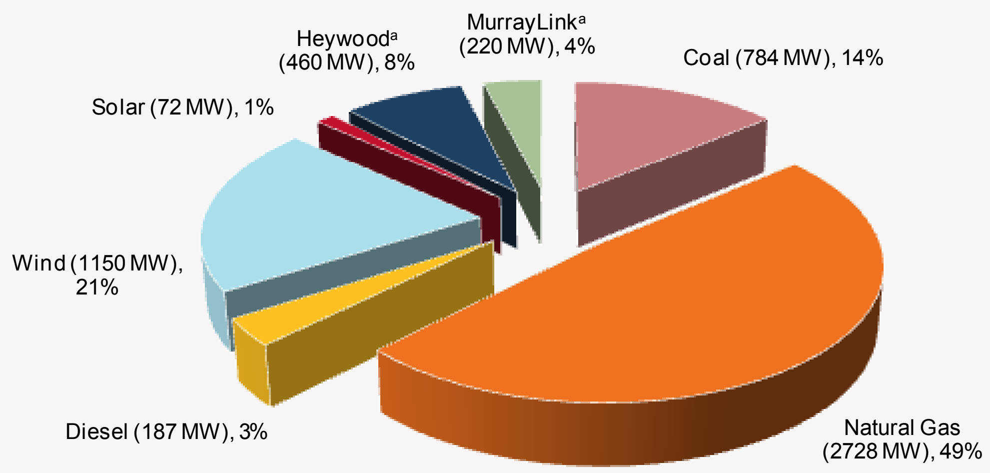
Further wind generation growth in South Australia could benefit from network augmentation. In 2010, AEMO and ElectraNet undertook a Joint Feasibility Study to examine a range of issues relating to network augmentation options between Victoria and South Australia. The study examined the existing interconnectors and the potential to develop a larger link to the eastern states. The results of this initial analysis were sufficiently positive that further work on assessing the feasibility of an augmentation of the Heywood interconnector is now likely to commence in 2011.

[5] According to the World Wind Energy Association's data (http://www.wwindea.org/home/index.php) this puts South Australia second behind Denmark in terms of penetration and the per capita figure of 0.702 kW per person is now higher than any major country in the world.

Electricity supply mix by fuel type

Figure 3 shows the installed capacity of all South Australian generators by fuel type and the interconnectors.

Figure 3 — Electricity supply by fuel type



[a] South Australia to Victoria interconnectors.

Electricity supply profiles

Figure 4 shows South Australia's annual energy by fuel type, with wind generation now supplying approximately 20% of annual demand.

Figure 4 — Annual energy by fuel type

Most of the electricity in South Australia is supplied by gas generation (44%), followed by coal (30%), and wind (20%). The remainder is supplied via the interconnectors, and small amounts of distillate, solar, and biomass generation.

Generation from coal and gas as a percentage of total energy has remained relatively static over the past six years, while supplies from other regions remain low when compared to the start of the National Electricity Market (NEM).

The South Australian Feed-In Tariff Scheme and Australian Government rebates delivered significant numbers of roof-top photovoltaic installations, which now contribute more energy annually than distillate-fired generation.

After an intensive examination of the network capability by AEMO and ElectraNet, the stability limit for exports from South Australia to Victoria was increased to 580 MW in January 2011. However, the full capacity will not always be available due to other network limitations.

Low market prices

The 2010/11 South Australian wholesale electricity market price is at its lowest since the start of the NEM.

Table 2 shows the volume-weighted[6] earnings prices for both renewable and thermal generation types, and the volume and time-weighted wholesale market prices for South Australia.

[6] The total value of the energy traded in the market divided by the total quantity of energy produced, better representing the average price received by the market participant.

Table 2 — Volume-weighted wholesale market prices for South Australia since 2004

Financial year	Renewable		Thermal		South Australian Market		
	Full year ($/MWh)	Summer ($/MWh)	Full year ($/MWh)	Summer ($/MWh)	Full year ($/MWh)	Summer ($/MWh)	Full year time-weighted ($/MWh)
2003/04	33.09	40.56	39.96	50.43	43.85	61.09	38.33
2004/05	38.47	56.72	44.56	67.50	44.61	67.92	39.10
2005/06	32.57	39.59	43.91	67.50	43.26	65.78	37.76
2006/07	49.69	51.55	58.71	67.21	58.35	66.43	51.61
2007/08	63.31	63.94	102.01	149.92	98.46	142.32	73.50
2008/09	46.39	91.80	70.50	165.34	67.16	155.12	50.98
2009/10	47.39	77.43	86.69	140.98	80.17	131.01	55.31
2010/11[a]	22.82	29.75	50.78	91.74	45.17	78.60	33.99

a. The values for the 2010/11 financial year are based on the period 1 July 2010 to 31 March 2011.

The lower price received by renewable generation is partly due to the significant portion of time where all the wind farms experience similar conditions, which tends to depress the South Australian regional price at those times. The relative gap between the volume-weighted earnings price received by thermal and renewable generation reflects the higher price received by thermal generators during periods when wind output is lower.

New generation investment slowed in 2010/11, which may be attributed to a number of concurrent market conditions including (but not limited to) low market prices, insufficient demand growth, and uncertainty about environmental policies.[7] The majority of new projects in South Australia, which are mostly in the early development stage, involve renewable or peaking generation.

Fuel supply

While Cooper and Eromanga basin gas reserves increased by 15% to December 2010, production continues to decline. In 2010, production was approximately a third of the peak rate that occurred in 2001. The proven and probable (2P) gas reserves are 1,396 PJ, and at the current rate of consumption are projected to last another 13 years. The 2P gas reserves figure is the latest information from RLMS[8], and may differ from the 2010 Gas Statement of Opportunities (GSOO). Sources of South Australian unconventional gas supplies are currently being investigated.

Overall, South Australia is a net importer of gas, receiving gas from Queensland and Victoria, and exporting small amounts to New South Wales. As at 31 December 2010, Eastern and South Eastern Australian 2P gas reserves were 43,798 PJ. At the current rate of consumption they are projected to last another 70 years.

Approximately 50% of potential pipeline capacity is used, and while significant investment in new gas powered generation will increase this usage, current augmentation options (for example, looping, additional compressors, and local storage) will enable the additional demand to be met.

7 Deloitte Report on Electricity Generation Investment Analysis, Final Report ,14 April 2011
8 Resource Land and Management Services (RLMS), March 2011.

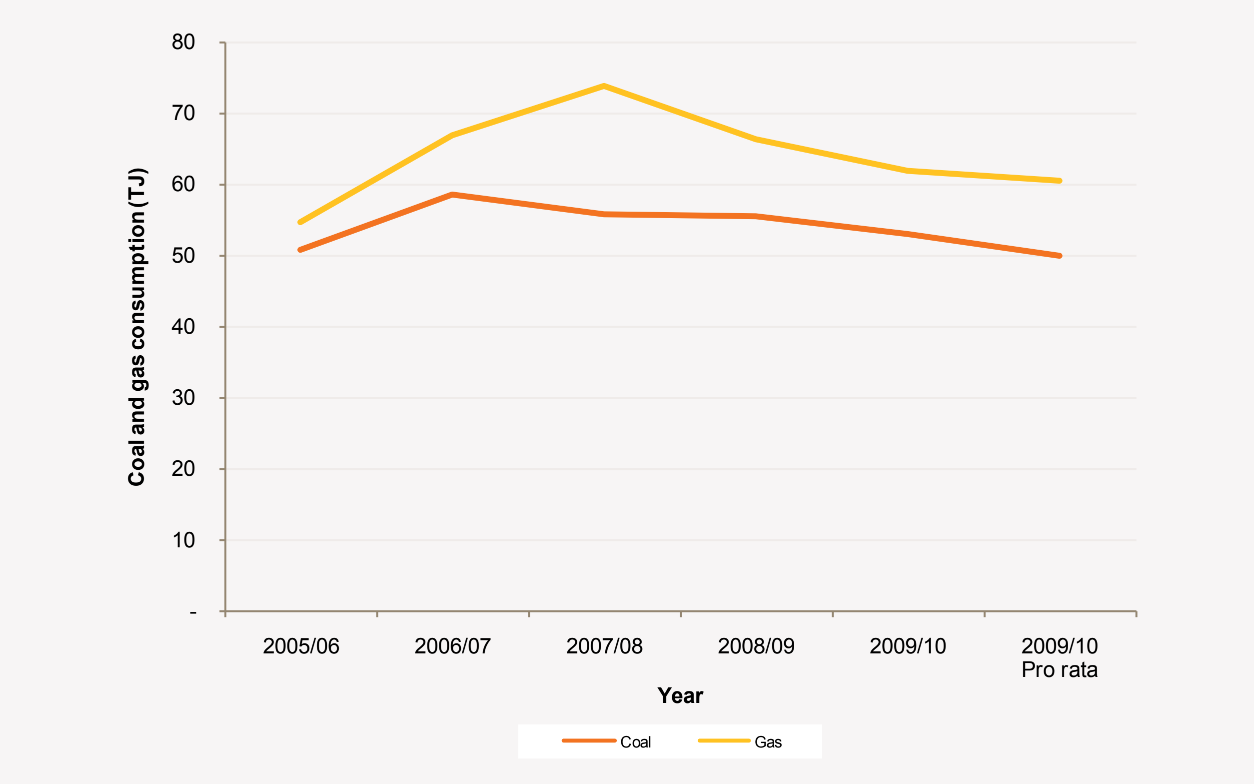
The Short-Term Trading Market for gas

The Short-Term Trading Market (STTM) started on 1 September 2010, facilitating gas trading using market-driven daily prices. The average gas price traded in the STTM at the Adelaide hub from 1 September 2010 (market start) to 23 May 2011 was 3.07 $/GJ. The average price for the same periods for the Sydney hub was 2.74 $/GJ.

Coal and gas consumption

Figure 5 shows coal and gas consumption in South Australia for the last six years, which has remained relatively constant.

Figure 5 — Coal and gas consumption for electricity generation



Supplies of Leigh Creek Coal for the Northern and Playford Power Stations at Port Augusta are being depleted. At the current rate of consumption, the economic reserves (of between 55 million and 85 million tonnes) are projected to last another 15 years[9], and a number of options to extend the mine's life or find alternate supplies have been investigated.[10] The increased costs of these alternatives may adversely impact power station operations and the competitive position of the generators.

South Australia has significant renewable energy resources, particularly wind, solar, and geothermal. While these come with negligible fuel costs, bringing the best resources to market has its challenges because of their location and/or high capital costs.

9 http://www.adelaidenow.com.au/business/alinta-seeks-coal-to-keep-power-plant-going/story-e6frede3-1226038658107, accessed 16 May 2011.

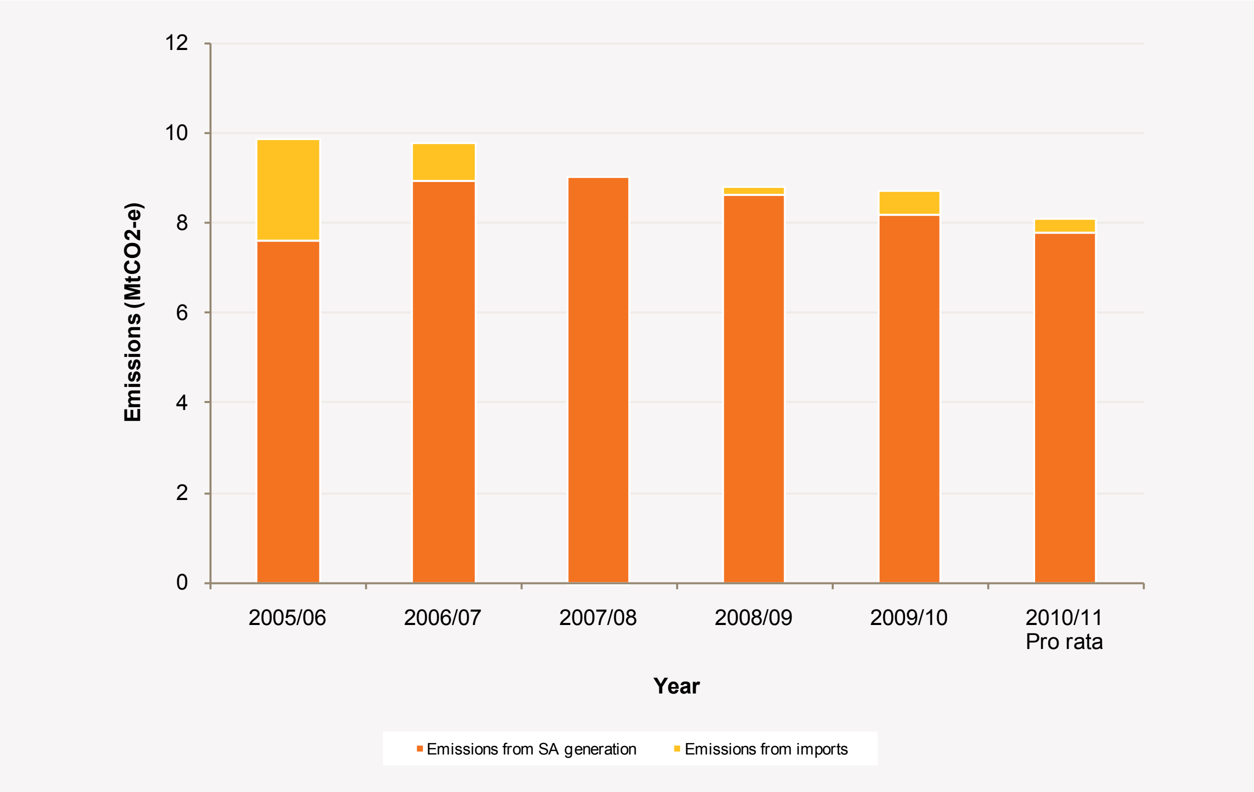
10 CQ Partners, "Leigh Creek Life Study", March 2011.

Greenhouse gas emissions

Responses to the annual generator survey indicate that there is strong interest in the development of more renewable projects in South Australia, and a number of projects may proceed once details of the Australian Government carbon price is made clear. Factors contributing to continued development interest include broad public and political support, and incentives from both the Federal Renewable Energy Target and South Australia's Renewable Energy Rebate Scheme.

Figure 6 shows South Australia's approximate annual carbon dioxide equivalent (CO2-e) emissions from generation. The trend shows a decline in emissions over the last few years predominantly due to increased wind generation. The net import from other regions of the NEM has also decreased since 2005/06.

Figure 6 — South Australian annual CO2-e emissions from generation



ACRONYMS

Definition	Description
ABS	Australian Bureau of Statistics
AC	Alternating current
ACCC	Australian Competition and Consumer Commission
AEMC	Australian Energy Markets Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AEST	Australian Eastern Standard Time
AGL	Australian Gas Light Company
AMD	Agreed maximum demand
APR	Annual planning report
°C	Celsius
CCGT	Combined cycle gas turbine
CCS	Carbon capture and storage
CIF	Cost and insurance freight
CO_2	Carbon-dioxide
CO2-e	Carbon dioxide equivalent
CSM	Coal seam methane
DC	Direct current
DNSP	Distribution network service provider
DSM	Demand-side management
DSP	Demand-side participation
EIS	Environmental impact statement
ESCOSA	Essential Services Commission of South Australia
ESIPC	Electricity Supply Industry Planning Council of South Australia
ESOO	Electricity Statement of Opportunities
EST	Eastern Standard Time
ETSAP	Energy Technology Systems Analysis Program
GDP	Gross domestic product
GJ	Gigajoules
GL	Gigalitre
GSOO	Gas Statement of Opportunities
GSP	Gross state product

Definition	Description
GT	Gas turbine
GWh	Gigawatt hours
HDR	Hot dry rock
HR	Hot rock
HSA	Hot sedimentary aquifers
HV	High voltage
IDGCC	Integrated drying and gasification combined cycle
IGCC	Integrated gasification and combined cycle
kV	kilovolt
LNG	Liquefied Natural Gas
LRET	Large-scale Renewable Energy Target
MAP	Moomba to Adelaide Pipeline (gas)
MD	Maximum demand
MRET	Mandatory renewable energy target
MSP	Moomba to Sydney Pipeline
Mt	Megatonne
MW	Megawatt
NEL	National Electricity Law
NEM	National Electricity Market
NEMDE	National Electricity Market Dispatch Engine
NER	National Energy Rules
NSP	Network service provider
NTNDP	National Transmission Network Development Plan
OCGT	Open cycle gas turbine
PC	Pulverised coal
POE	Probability of exceedence
PJ	Petajoule
PSA	Power System Adequacy
PV	Photovoltaic
RCP	Reciprocating engine
RET	Renewable Energy Target
RIT-T	Regulatory Investment Test for Transmission
SEAGas	South East Australia Gas Pipeline
SASDO	South Australian Supply and Demand Outlook
SRES	Small-scale Renewable Energy Scheme

Definition	Description
ST	Steam turbine
STTM	Short-Term Trading Market (gas)
t	Tonnes
TIPS	Torrens Island Power Station
TJ	Terajoule
TNSP	Transmission network service provider
UK	United Kingdom
US	United States
USE	Unserved energy
VAPR	Victorian Annual Planning Report
V	Volts

[This page is left blank intentionally]

CONTENTS

TABLES

FIGURES

[This page is left blank intentionally]

CHAPTER 1 - INTRODUCTION

The South Australian Supply and Demand Outlook (SASDO) is an independent report prepared by the Australian Energy Market Operator Limited (AEMO), which is published by 30 June to align with production of ElectraNet's South Australian Annual Planning Report.

The SASDO is a public document that provides information to the South Australian Government and the energy market to assist with operational, policy, and investment decisions. To this end, the publication presents electricity demand and generation forecasts, an analysis of historical data, and information about the current state of South Australia's electricity supply, including fuel and resource availability.

The SASDO is published for the South Australian jurisdiction in accordance with Section 50B of the National Electricity Law. AEMO also delivers additional advisory functions for the South Australian and National jurisdictions via a number of other publications, including the Electricity Statement of Opportunities (ESOO), Power System Adequacy - Two Year Outlook (PSA), and the National Transmission Network Development Plan (NTNDP).

Attachment 1 provides a list of these additional advisory functions and the relevant supporting documents.

1.1 AEMO's planning documents

In 2011, AEMO will publish six planning documents, each of which satisfies a unique demand for energy market information stemming from AEMO's various planning roles. Increasingly, AEMO aims to ensure that their common elements provide a consistent and coherent message.

Table 1-1 lists AEMO's planning publications for 2011, and the unique and common elements of each.

Table 1-1 — AEMO's planning documents

	South Australian Supply and Demand Outlook	Victorian Annual Planning Report	Electricity Statement of Opportunities	Power System Adequacy - Two Year Outlook	Gas Statement of Opportunities	National Transmission Network Development Plan
Published	30 June	30 June	31 August	31 August	30 November	31 December
Focus	South Australian electricity	Victorian gas and electricity	NEM electricity	NEM electricity	Eastern Australian gas and detailed Victorian gas forecasts	NEM electricity
Outlook	10 years	10 years (5–year focus)	10 years	2 years	20 years (5–year detailed Victorian gas forecasts)	20 years
Gas forecasts	n/a	✓	n/a	n/a	✓	n/a
Electricity forecasts	✓	✓	✓	✓	n/a	✓

The SASDO outlines information about South Australian electricity supply, demand, and fuel resources. The Victorian Annual Planning Report (VAPR) satisfies AEMO's Victorian gas and electricity transmission planning roles. Both documents are published at the end of June to align with National Electricity Rules (NER) requirements regarding annual planning report publication.

In August, AEMO will publish the ESOO, which provides a long-term outlook for National Electricity Market (NEM) supply and demand that focuses on the next 10 years. The PSA, which is published at the same time, provides a more detailed operational outlook focusing on the next two years.

The Gas Statement of Opportunities (GSOO) aims to assist existing participants and new investors with information about commercial decisions about infrastructure investment in the Eastern and South Eastern Australian gas industry.

The NTNDP is a long-term independent strategic plan for the NEM that explores potential NEM transmission impacts. The NTNDP will be released in late December 2011.

1.2 South Australian energy market participants

The South Australian energy market can be divided into four categories:

- fuel providers
- generators
- networks (both transmission and distribution), and
- retail.

Figure 1-1 shows the market participants in each of these categories, together with the market management, operations, planning, and regulation entities. The Essential Services Commission of South Australia (ESCOSA) maintains industry fact sheets on the gas[11] and electricity[12] industries, and licensing information for retailers, distributors, and generators for South Australia. The market participants included in Figure 1-1 are licensed with ESCOSA and registered as market participants with AEMO.[13]

Figure 1-1 represents both gas and electricity market participants, where gas pipeline owners are represented in both the transmission and fuels categories to reflect the transmission of gas via pipelines.

[11] http://www.escosa.sa.gov.au/Publications/DownloadPublication.aspx?id=1787.

[12] http://www.escosa.sa.gov.au/Publications/DownloadPublication.aspx?id=1786.

[13] The list of registered market participants and the participant categories can be found on the AEMO website at: http://www.aemo.com.au/registration/registration.html. Licensed South Australian participants were sourced from www.escosa.sa.gov.au. The advice from ESCOSA enabling the differentiation of active, grid-connected participants is gratefully acknowledged.

Figure 1-1 — South Australian energy market participants

Fuels

Oil and Gas

Gas

Generation

No direct license, but has holdings in one or more licensed wind farms in SA

Networks

Transmission

Distribution

Retail

Registered

Planning to retail

Hold licences but not currently operating in SA

Market management, operations, planning and regulation

Note: The Ministerial Council on Energy (MCE) will be replaced by the Standing Committee on Energy and Resources as of 1 July 2011.

[This page is left blank intentionally]

CHAPTER 2 - ELECTRICITY DEMAND FORECASTS

2.1 Summary

This chapter provides a review of electricity demand during summer 2010/11, 10-year demand forecasts for energy, and summer and winter maximum demand.

Summer 2010/11 maximum demand

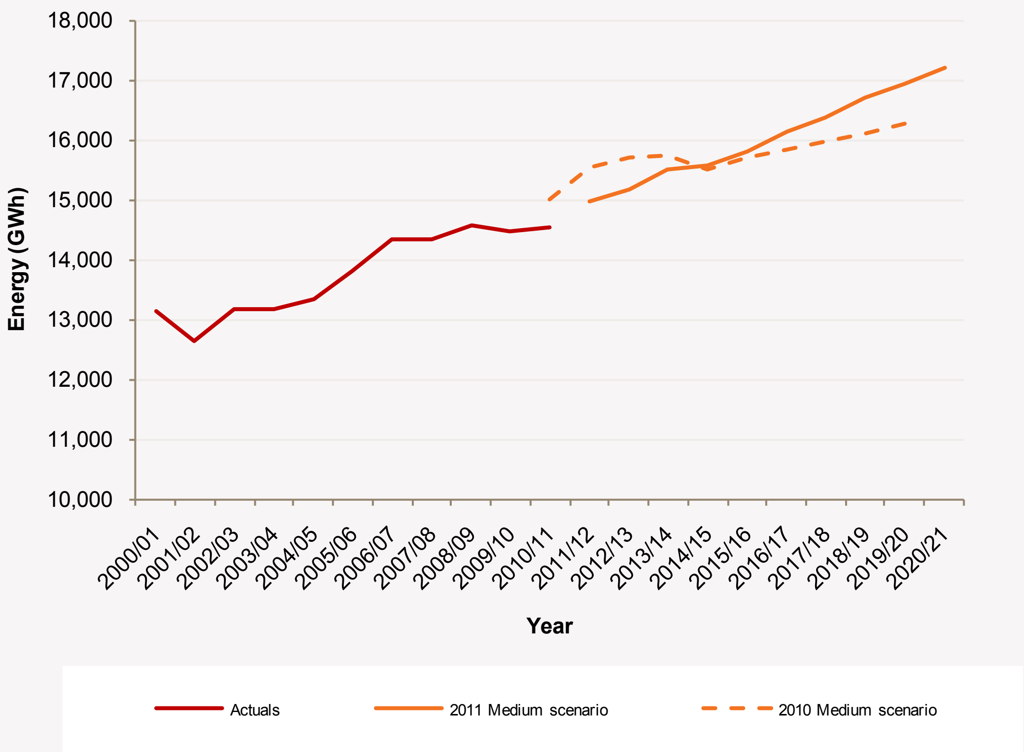
South Australia's 2010/11 summer was characterised by record rainfall levels and lower average temperatures than recent years. There were fewer hot days (with a maximum temperature over 35 ºC) than in recent summers. Consequently there were fewer high-demand events.

Maximum demand met by generation for summer 2010/11 was 3,433 MW at 4:30 PM (Australian Eastern Standard Time) on 31 January 2011, which had approximately a one-in-six year probability of occurrence. This exceeds the previous South Australian demand record of 3,413 MW on 29 January 2009.

Annual Energy forecasts

Under the medium economic growth (medium growth) scenario, annual energy is projected to increase over the next 10 years by an average of 1.7% each year, to 17,175 GWh in 2020/21. Figure 2-1 shows that the 2011 forecasts for summer 2011/12 and summer 2012/13 are lower than the 2010 forecasts. However from 2014/15 onwards the 2011 forecasts are higher than the 2010 forecasts by up to 682 GWh by 2019/20. These changes are primarily due to increases to the medium growth scenario gross state product (GSP) forecasts and industrial load forecasts since last year.

Figure 2-1 — Electrical energy forecasts (medium growth scenario)

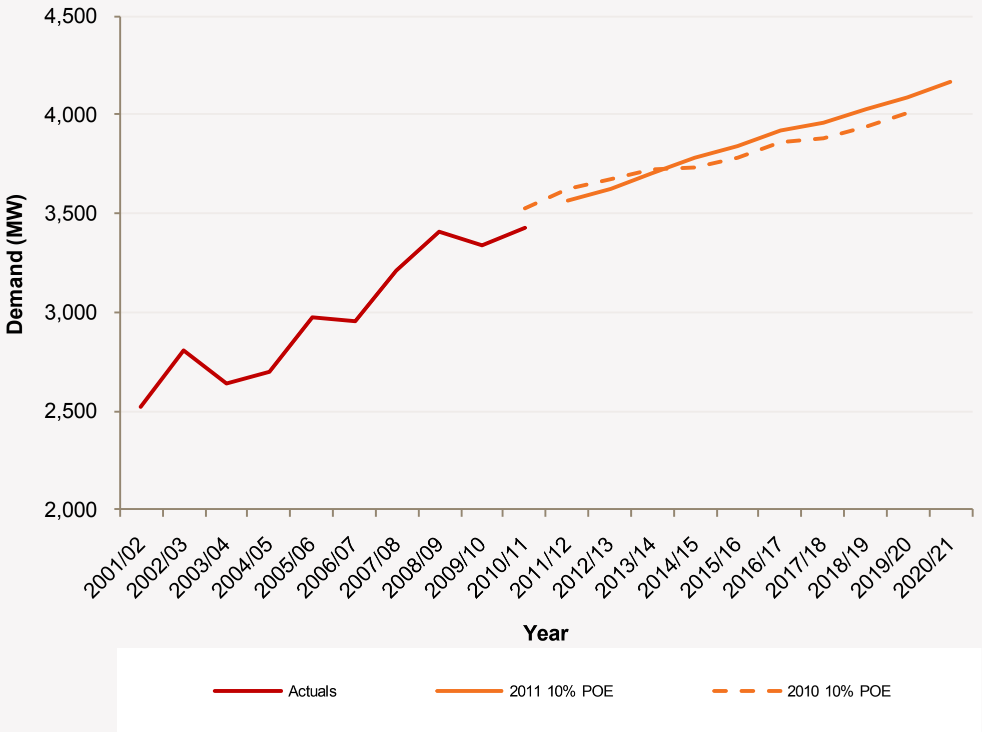


Maximum demand forecasts

Figure 2-2 shows historic maximum demand as well as the projected maximum demand at a 10% probability of exceedence (POE). The 10% POE projections represent one case and there are other scenarios detailed in Section 2.6.2.

Under the medium growth scenario, the 10% POE maximum demand is projected to increase over the next 10 years by an average of 1.9% each year, to 4,170 MW in 2020/21. Figure 2-2 shows that the 2011 forecasts for summer 2011/12 and summer 2012/13 are slightly lower than the 2010 forecasts, but from 2013/14 onwards the 2011 forecasts are higher than the 2010 forecasts. This reflects changes in carbon price assumptions from 2010, where a considerable jump in prices in 2014/15 was expected at the commencement of an emission trading scheme. More recent assumptions about the impact of carbon pricing with respect to electricity demand results in steadier growth as described in the section 2.2.

Figure 2-2 — Summer maximum demand forecasts (medium growth scenario)



Key assumptions

The electricity demand forecasts in this document were prepared using the assumption that the Australian Government would introduce a carbon price of 10 \$/t CO2-e in 2013/14, before implementing the full emissions trading scheme in 2014/15. The 10 \$/t CO2-e in 2013/14 price assumption was developed by AEMO in 2009 for the 2010 NTNDP scenarios, in consultation with industry stakeholders. The carbon prices assumed from 2014/15 onwards reflect the latest (2008) Australian Government Treasury modelling related to the potential economic impacts of reducing emissions over the medium and long term.[14] The carbon price under each scenario is assumed to grow at a real rate of 4% per annum from 2014/15 onwards, reflecting the fact that carbon permits are financial assets and are bankable over time. This assumption is based on a 2% annual return and 2% risk

[14] Commonwealth of Australia, "Australia's Low Pollution Future: The Economics of Climate Change Mitigation" 2008.

premium.

After the scenarios were developed, the government announced its plan to introduce a fixed carbon price from 1 July 2012, followed by a full emissions trading within three to five years. This change does not affect the long-term carbon price projections in the scenarios. The different start dates and starting prices will have only a short-term impact, as the longer-term carbon emissions reductions targets for each scenario are assumed to be unchanged. Since the forecast long-term carbon price trajectory is substantially unchanged, there is no material effect on the macro-economic parameters, and only a small impact on the overall long-term trend in electricity prices. Consequently the energy and maximum demand forecasts presented in the 2011 SASDO remain valid. Once emissions trading is introduced the carbon price will be determined by the market, taking into account the level of reduction required and the costs of providing it, as modelled for each scenario.

2.2 Introduction

Electricity forecasts presented in this chapter cover annual energy consumption and maximum demand, for both summer and winter. These forecasts are based on econometric models that link demand to prevailing weather conditions, electricity prices and other demographic and economic drivers.

Demand definition

Electricity supply is instantaneous, which means it cannot be stored, and supply must equal demand at all times. The NEM provides a central dispatch mechanism that adjusts supply through the dispatch of generation every five minutes to meet demand.

AEMO defines electricity demand as the amount of power supplied to the transmission network from generation rather than the amount being consumed by customers. This automatically includes the energy lost transporting the electricity (network losses), electricity used by the generators themselves to generate the electricity (auxiliary loads), and electricity used by customers.

Off-grid supply to remote customers is not included in the forecasts. The contribution from unmetered, small-scale distributed generation is estimated but excluded from the forecasts. For example, household roof-top photovoltaic systems, energy efficiency, and load control initiatives reduce customer demand from the network and are reflected as lower projected growth. From the NEM's perspective, separating the effect of increased local generation, improvements in energy efficiency, and customers controlling their loads at times of high prices and reduced growth rates can be problematic.

For more information about key energy and demand definitions, see Chapter 4.2 of the 2010 Electricity Statement of Opportunities (ESOO).

2.3 Review of electricity demand - 2010/11 summer

The 2010/11 South Australian summer was characterised by relatively mild temperatures and record high rainfall. Average temperatures[15] in Adelaide were closer to the long-run average than they have been for the previous five years.

Figure 2-3 and Figure 2-4 show the daily maximum demand and average temperatures during the extended 2010/11 summer period (1 November 2010 to 31 March 2011). These figures demonstrate the:

- correlation between average temperature and daily maximum demand, and
- high volatility of daily maximum demand between 1,500 MW and 3,400 MW.

[15] The average temperature for a given day is the average of the overnight minimum and daily maximum temperature at Kent Town weather station in Adelaide.

Figure 2-3 — Daily maximum demand and daily average temperature from 1 November 2010 to 31 March 2011

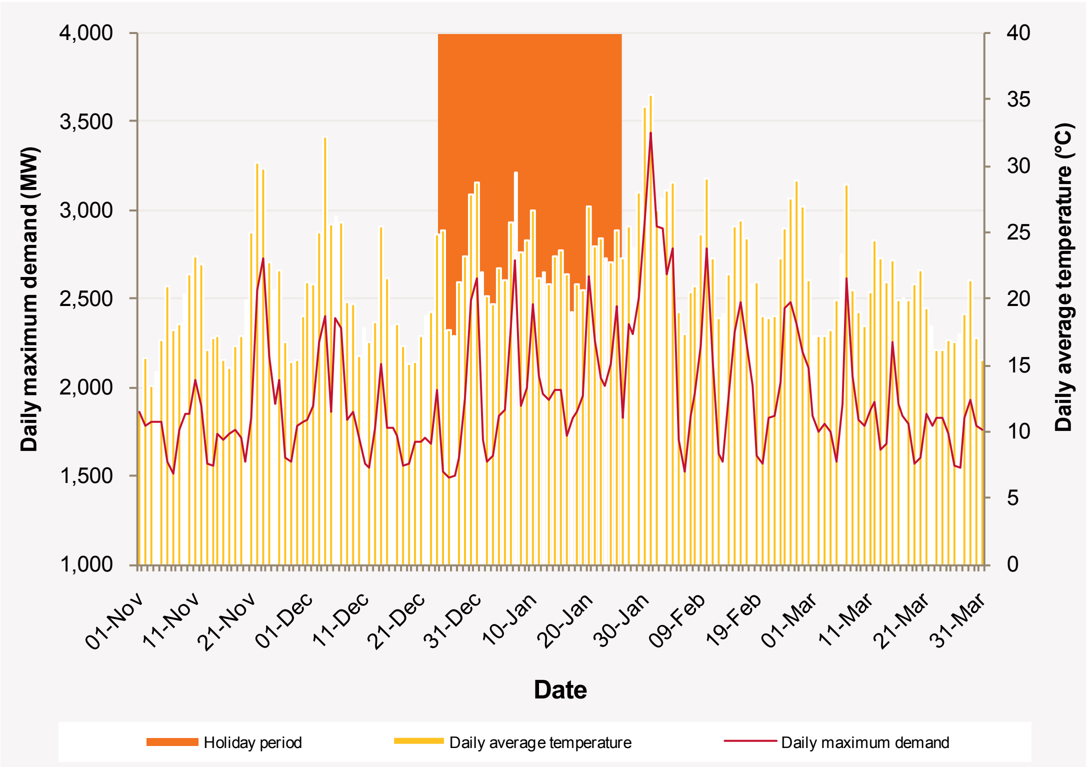
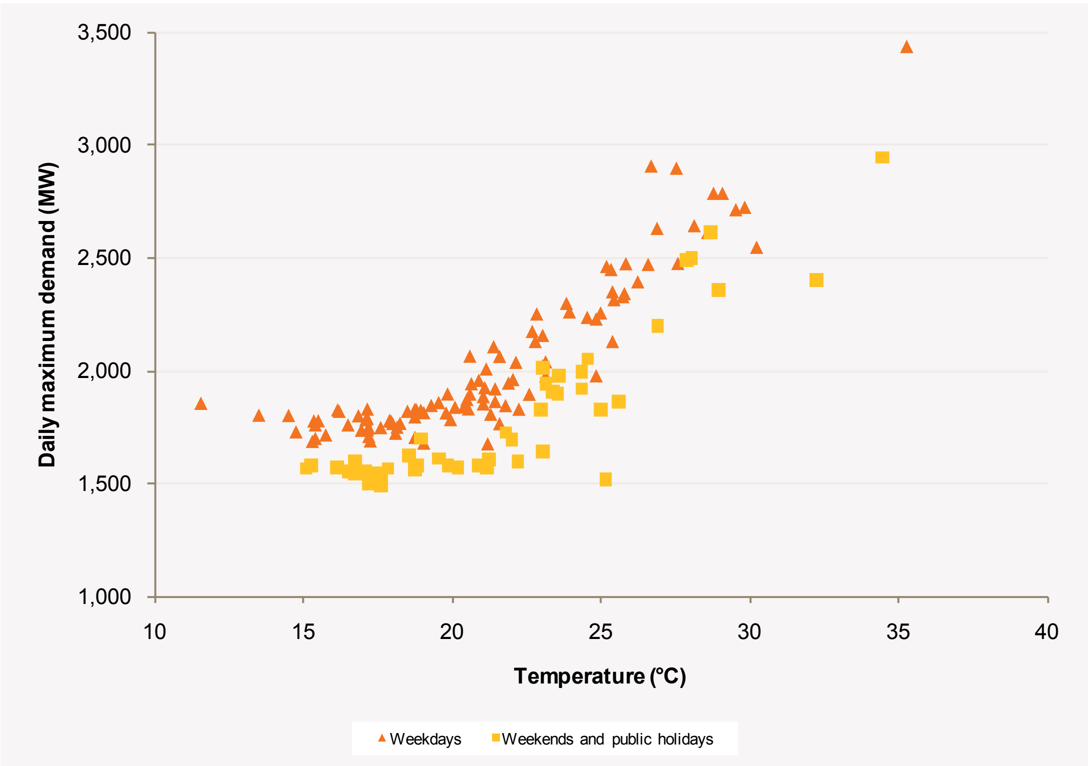


Figure 2-4 — Daily maximum demand vs daily average temperature for summer 2010/11



There were fewer days with very high temperature during this summer. Figure 2-5 shows the number of hot days and the average summer temperatures for the past six years. The 2010/11 summer had less than half the number of high temperature days compared with previous summers.

Figure 2-5 — Number of hot days and average summer temperature

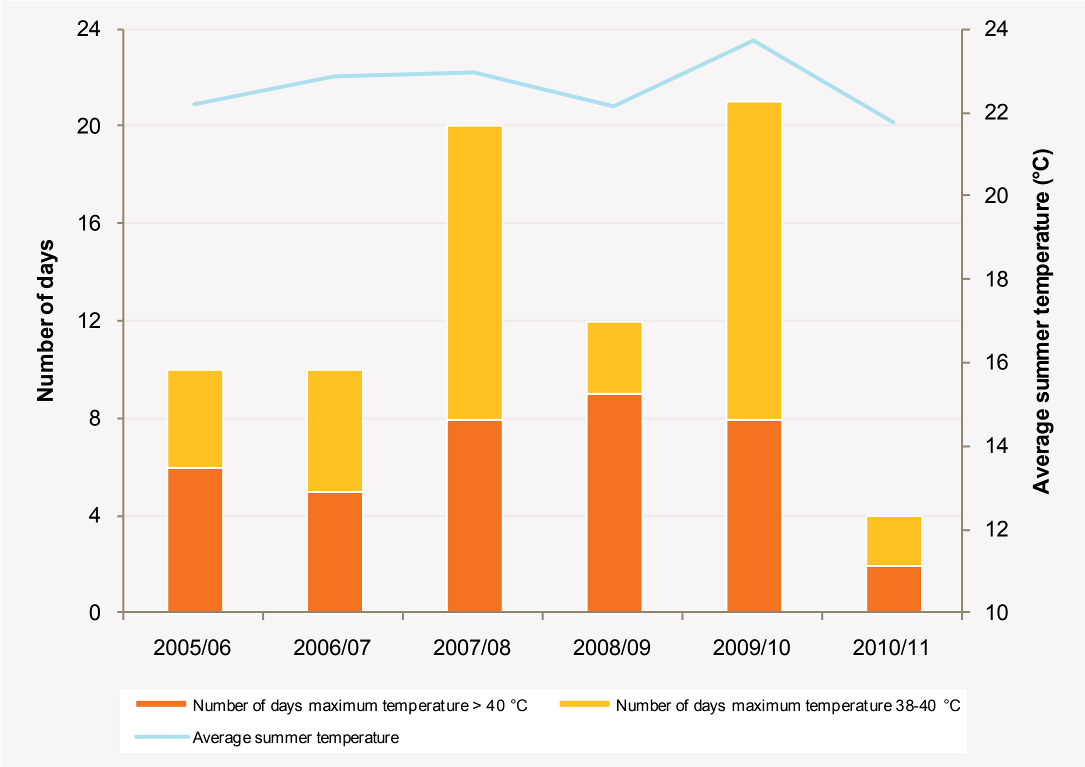
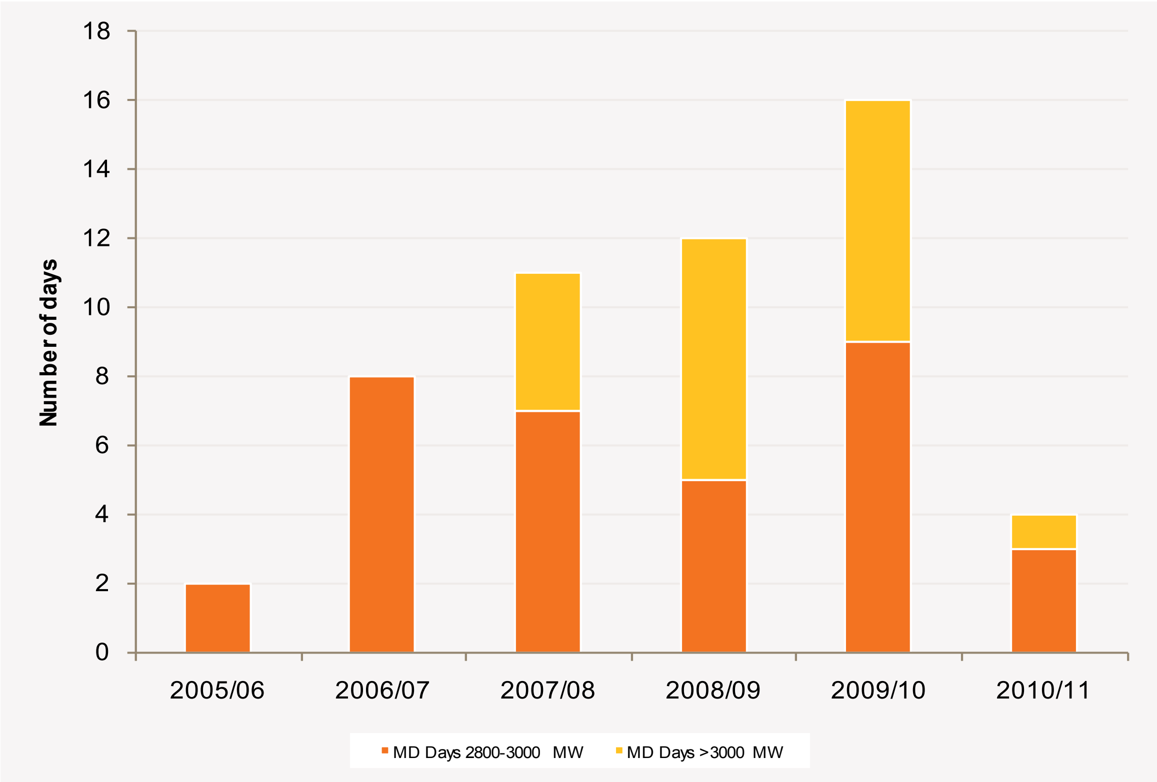


Figure 2-6 presents the total number of days with maximum demand from 2,800 MW to 3,000 MW and over 3,000 MW. There were few days with high demand during the 2010/11 summer compared with previous years, particularly when taking into account underlying growth in maximum demand over time.

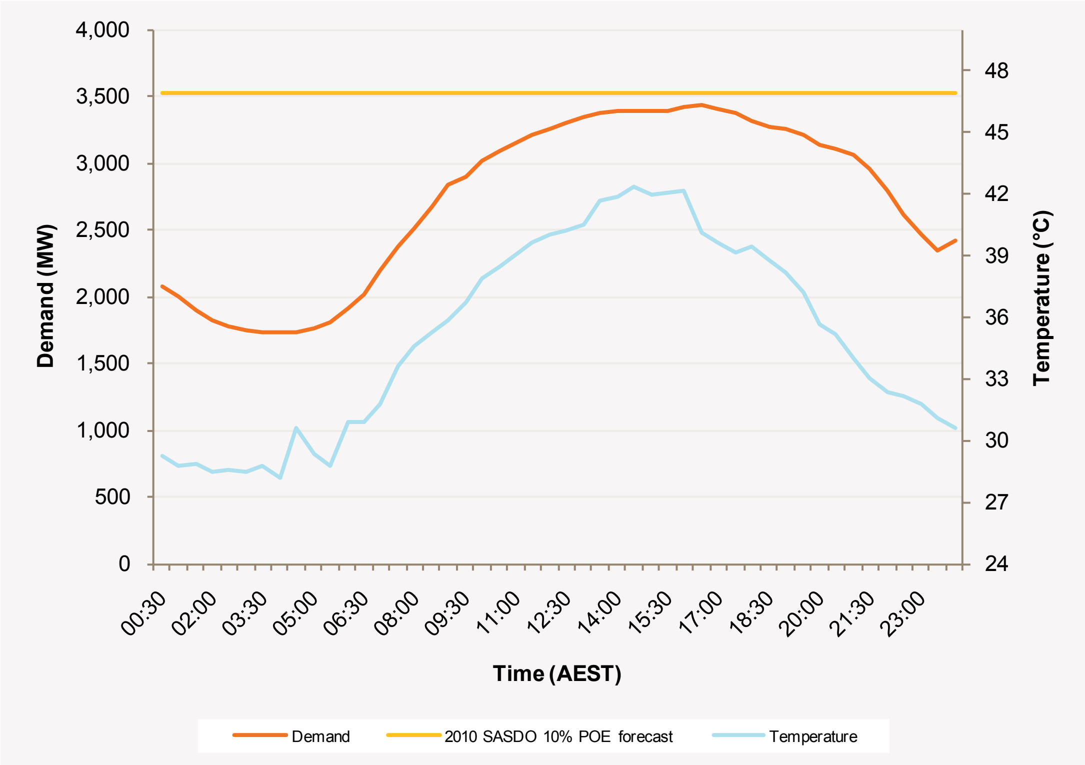
Figure 2-6 — Maximum demand (MD) days for recent summers



This year a new record maximum demand was set for South Australia. On 31 January 2011 at 4:30 PM AEST, demand reached 3,433 MW, surpassing the previous record of 3,413 MW (on 29 January 2009). 31 January 2011 was the first day of the school term for public schools, and most major industries had returned to normal operation following the Christmas break.

Figure 2-7 shows the demand and temperature throughout the day, with temperature peaking at 42.9 °C. The plot also shows the 10% POE maximum demand forecast from the 2010 SASDO.

Figure 2-7 — Electricity demand and temperature on 31 January 2011



The top five demand days for summer all occurred in the period from 30 January 2011 to 4 February 2011. Table 2-1 shows the temperature and maximum demands for these five days. For more information about the contribution of wind power during peak demand periods, see Section 5.4.

Table 2-1 — Summer 2010-11 maximum demand occurrences and temperatures

Time (AEST) and Date	Temperature (°C)			Demand (MW)
	Maximum	Minimum	Average	
4:30 PM Monday 31 January 2011	42	28	35	3,433
6:00 PM Sunday 30 January 2011	42	27	34	2,947
2:00 PM Tuesday 1 February 2011	33	21	27	2,906
4:00 PM Wednesday 2 February 2011	36	20	28	2,897
2:30 PM Friday 4 February 2011	34	24	29	2,786

2.4 Drivers of electricity demand

The electricity forecasts presented in this chapter rely on assumptions concerning energy policy, energy market trends, and macroeconomic factors such as gross domestic product (GDP), gross state product (GSP) and population. Attachment A2 - Economic outlook provides details about the GDP forecasts. KPMG modelled three economic growth scenarios representing relatively low, medium, and high levels of economic activity, taking into account these drivers. This section provides background on these scenarios and the policy and price assumptions that were incorporated into the forecasts.

2.4.1 South Australian economic outlook

This section describes the South Australian gross state product scenarios developed by KPMG.

Economic growth is a strong driver for electricity demand because increased economic output is generally linked to goods and services that require energy inputs. Economic growth associated with an expanding population also drives electricity demand through the connection of new houses to the network.

Figure 2-8 shows the historical and projected GSP growth for South Australia over the forecast period for the low, medium, and high economic growth scenarios. These forecasts were developed in March 2011 based on actual growth up to and including September 2010.

GSP growth in recent years

The South Australian economy slowed in 2008/09, due to the effects of the global financial crisis, particularly a scaling back of production in the automotive manufacturing sector. In 2009/10 GSP showed some recovery from the crisis, boosted by solid growth in the agricultural sector. Favourable growing conditions across most regions saw the winter crop production expand by an estimated 53%. Targeted stimulus measures also contributed to the increase in growth for 2009/10, with the government's First Home Owners Boost supporting a spike in dwelling investment in late 2009, which resulted in stronger construction activity in 2010.

Despite these increases in economic activity, growth in 2009/10 was lower than previously expected. This was mainly due to reduced mining output resulting from damage to a hauling shaft at the Olympic Dam mine in October 2009.

GSP outlook to 2020/21

Under the medium growth scenario it is expected that a decline in exports from the wine and automobile industries will impact negatively on GSP. Despite this forecast decline in manufacturing, GSP growth under the medium growth scenario is forecast at a relatively fast annual average of 3.1% over the next five years. This is due to projected increases in dwelling investment, combined with stronger business investment and growth in consumer spending.

Over the medium to longer term, mining exports for the state are expected to grow strongly, which will continue to offset slower growth in wine and automobile exports. The historically high level of infrastructure spending in South Australia[16] is also expected to drive medium-term GSP growth.

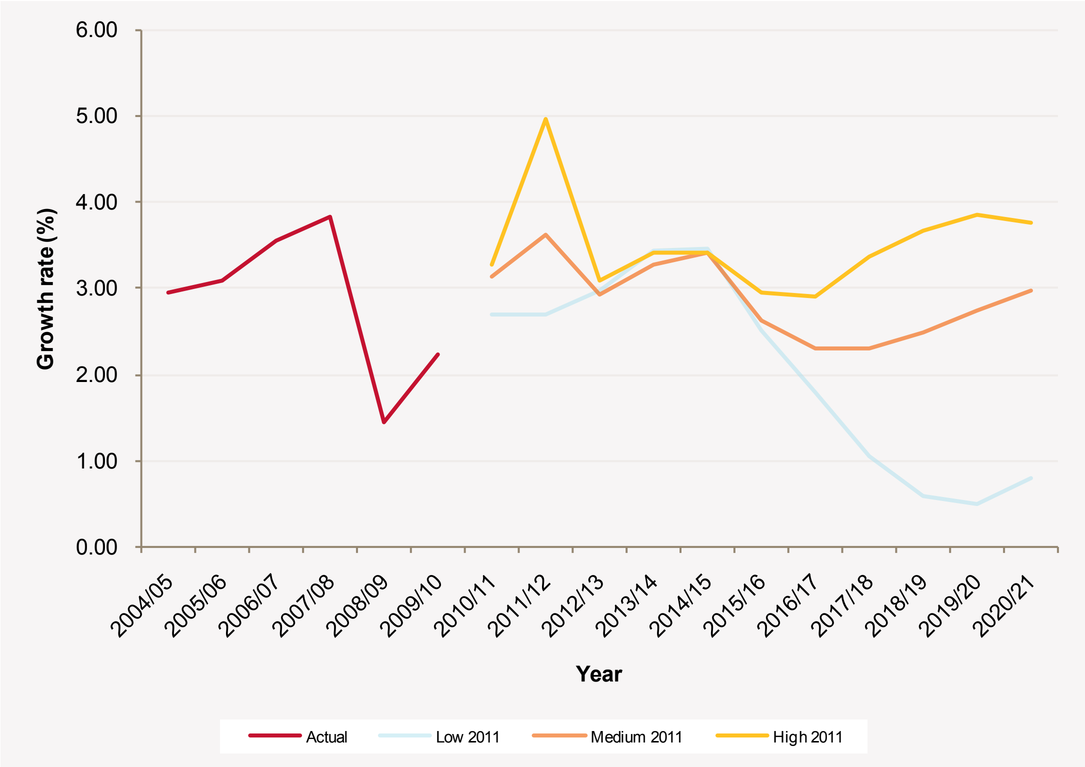
Under the low growth scenario, GSP forecasts are much slower than the baseline, reflecting weaker business investment due to higher risk premiums, as well as lower levels of housing investment and relatively poor trade performance.

Under the high growth scenario, strong population growth supports fast-paced growth in dwelling investment, while a lower risk premium facilitates greater business investment.

Attachment A2 - Economic outlook contains a comparison of this year's economic outlook with the 2010 SASDO assumptions.

[16] According to KPMG, "Stage 2 Report: Economic scenarios and forecasts 2010-11 to 2034-35, A report to the Australian Energy Market Operator (AEMO)". April 2011, the South Australian Government currently has a record $71.5 billion worth of major projects either underway or in the pipeline, including the Port Stanvac desalination plant and the electrification of the metropolitan train network.

Figure 2-8 — Projected South Australian GSP growth (real)



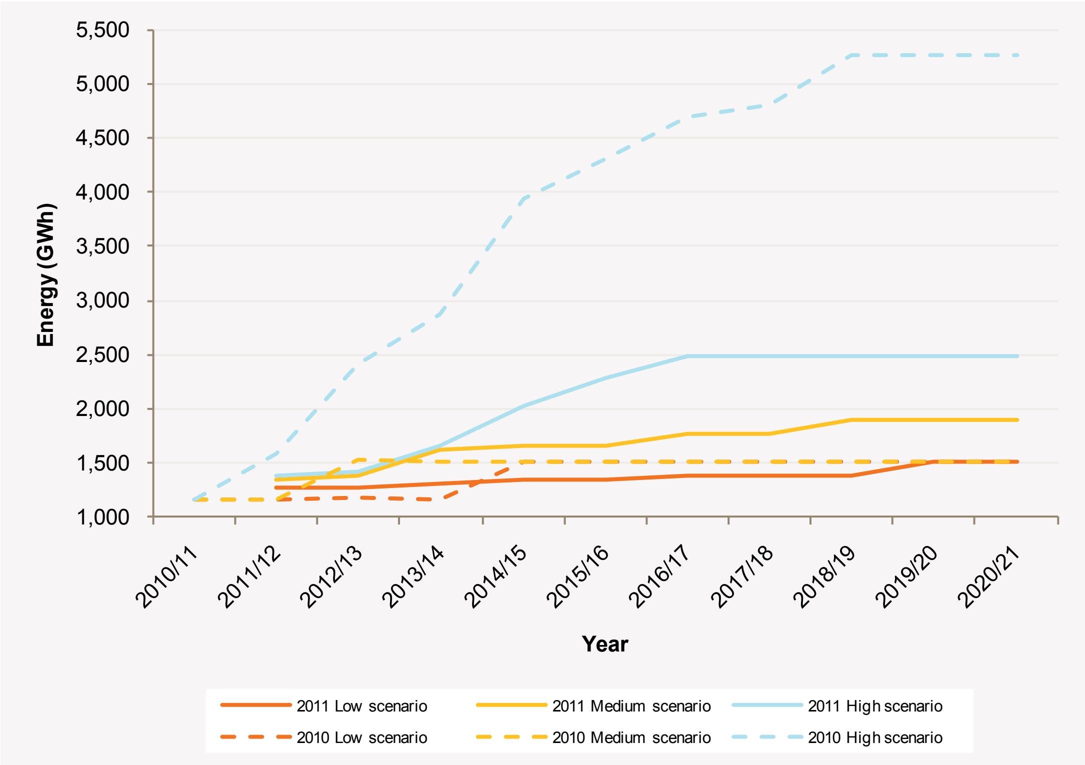
Major industrial loads

Assumptions regarding major industrial load growth are incorporated into the forecasts separately to the economic outlook when appropriate information is available from industry. New desalination plant and mining loads have been incorporated into the forecasts this year. The energy forecasts for these loads are presented in Figure 2-9. Last year's assumptions for industrial loads are also included for comparison.

Desalination Plant – the low, medium, and high growth scenario forecasts assume commissioning of the Port Stanvac (Lonsdale) 100 GL/year desalination plant to service Adelaide's water requirements. A desalination plant of this size is estimated to consume 500 GWh per annum and have a maximum demand of 80 MW. While first water is expected to be delivered in late 2011, the impact on South Australia's energy and peak demand consumption is not expected to be seen until 2012/13 in the high growth scenario, 2013/14 in the medium growth scenario, and 2014/15 in the low growth scenario.

Mining Expansion – expansion of mining in South Australia is also included in the low, medium and high growth scenario forecasts. The high growth scenario assumes continued expansion to 2016/17, the medium growth scenario assumes expansion to 2013/14, and the low growth assumes expansion concludes at the end of 2010/11.

Figure 2-9 — Major industrial load forecast



2.4.2 Energy policies and prices

Carbon price assumptions

The potential introduction of a price on carbon emissions has significant implications for electricity forecasts through its impact on drivers such as electricity prices and economic growth. The economic modelling carried out by KPMG has incorporated specific assumptions regarding a carbon price.

The electricity demand forecasts in this document were prepared using the assumption that the Australian Government would introduce a carbon price of 10 $/t CO2-e in 2013/14, before implementing the full emissions trading scheme in 2014/15. The 10 $/t CO2-e in 2013/14 price assumption was developed by AEMO in 2009 for the 2010 NTNDP scenarios, in consultation with industry stakeholders. The carbon prices assumed from 2014/15 onwards reflect the latest (2008) Australian Government Treasury modelling related to the potential economic impacts of reducing emissions over the medium and long term[17]. The carbon price under each scenario is assumed to grow at a real rate of 4% per annum from 2014/15 onwards, reflecting the fact that carbon permits are financial assets and are bankable over time. This assumption is based on a 2% annual return and 2% risk premium. These prices and other assumptions are listed in Table 2-2.

After the economic growth scenarios were developed, the government announced its plan to introduce a fixed carbon price from 1 July 2012, followed by a transition to emissions trading within three to five years. This change does not affect the long-term carbon price projections in the scenarios. The different start dates and starting prices will have only a short-term impact, as the longer-term carbon emissions reductions targets for each scenario are assumed to be unchanged. Since the forecast long-term carbon price trajectory is substantially unchanged, there is no material effect on the macro-economic parameters, and only a small impact on the overall long-term trend in electricity prices. Consequently the energy and maximum demand forecasts presented in the 2011 SASDO remain

[17] Commonwealth of Australia, "Australia's Low Pollution Future: The Economics of Climate Change Mitigation" 2008.

valid. Once emissions trading is introduced, the carbon price will be determined by the market, taking into account the level of emissions reduction required, as modelled for each scenario.

Table 2-2 — Carbon price assumptions

Low growth scenario	Medium growth scenario	High growth scenario
• Low emissions reduction targets agreed internationally.	• Moderate emissions reduction targets in Australia and internationally.	• International agreement of strong emissions reduction targets.
• Carbon price based on Treasury estimates for a cut in emissions of 5% on 2000 levels by 2020.	• Carbon price based on Treasury estimates for a cut in emissions of 15% on 2000 levels by 2020.	• Carbon price based on Treasury estimates for a cut in emissions of 25% on 2000 levels by 2020.
Carbon prices		
• 10.00 \$/t CO2-e for 2013/14.	• 10.00 \$/t CO2-e for 2013/14.	• 10.00 \$/t CO2-e for 2013/14.
• 26.91 \$/t CO2-e in 2014/15.	• 37.44 \$/t CO2-e in 2014/15.	• 49.97 \$/t CO2-e in 2014/15.
• Carbon price grows by real rate of 4% p.a. from 2014/15 onwards.	• Carbon price grows by real rate of 4% p.a. from 2014/15 onwards.	• Carbon price grows by real rate of 4% p.a. from 2014/15 onwards.
• Peaks at 48.46 \$/t CO2-e in 2030.	• Peaks at 67.36 \$/t CO2-e in 2030.	• Peaks at 90.00 \$/t CO2-e in 2030.

Other energy policy assumptions

The Australian Government Renewable Energy Target and South Australia's Residential Energy Efficiency Scheme (both described in Attachment A1 - Energy policies and forecast assumptions) are two policies that AEMO considered may affect future electricity prices. Consequently, KPMG tested this potential alongside the carbon price assumptions described in Table 2-2. It was found that the electricity price impacts of both policies were not significant. As a result, the effect of these schemes on price and demand are not incorporated into the modelling.

Electricity price assumptions

Average retail electricity prices are an important driver of annual electricity consumption and maximum demand. The price elasticity of electricity demand was assessed in 2008 as part of the South Australian demand forecast analysis performed for AEMO by Monash University.[18] The annual price elasticity[19] of electricity demand is estimated to be 0.25, with slightly less than half this applying to peak demand (that is, a 4% real rise in prices is expected to lead to a 1% reduction in annual demand and a 0.5% reduction in peak demand).

Electricity prices are expected to increase, as global demand for commodities increases the price of fuel and contributes to rising input costs for electricity generators. The assumed introduction of a carbon price by 2013/14 will also increase retail electricity prices as a portion of the carbon price is passed on to consumers through higher retail prices.

2.5 Demand forecast methodology

This section provides background on the methodology used for the SASDO energy forecasts. The input data are described, followed by a summary of the modelling approach used by Monash University in preparing the forecasts.

2.5.1 Input data

The main types of input data are historical data and economic and demographic assumptions.

[18] Fan, S and Hyndman, R J "The price elasticity of electricity demand in South Australia and Victoria", 2008. Available from http://www.buseco.monash.edu.au/ebs/pubs/wpapers/2010/wp16-10.pdf.

[19] The proportional change in quantity demanded in response to each percentage change in price (see glossary).

Historical demand data

Historical electricity demand data is the primary input and is approximated by aggregating generating unit output data.

AEMO collects data for the following generating units:

- all conventional thermal generation, whose output is determined in the NEM dispatch process
- all South Australian wind farms - wind farms either participate in the NEM dispatch as semi-scheduled or scheduled generating units, or operate as non-scheduled generating units[20], and
- several small-scale, non-scheduled generating units whose output is not controlled by NEM dispatch - this type of generating unit includes diesel generators connected to the distribution network.

Weather data

The forecasts use historical temperature data from the Bureau of Meteorology's Adelaide Kent Town and Adelaide Airport weather stations.

Assumptions are also made for temperature changes due to climate change based on Commonwealth Scientific and Industrial Research Organisation (CSIRO) modelling of future increases in temperature. The shifts in temperature to 2030 are predicted by the CSIRO to be 0.3 °C, 0.9 °C and 1.5 °C at the 10th, 50th and 90th percentiles respectively.

Economic and demographic information

Historical demographic and economic data including population, GSP and average electricity price are used to develop the economic scenarios described in Section 2.4.1.

2.5.2 Demand forecast models

The annual energy and maximum demand forecasts are prepared using a model developed by Monash University using the input data described in Section 2.5.1.

Modelling parameters

Parametric models are used to predict electricity demand based on its relationship to several underlying parameters that drive electricity consumption. In order to develop the model, the drivers that have the most significant effect on electricity demand must be identified. The best combination of variables for predicting South Australian demand was found to be per-capita GSP, average electricity price, summer cooling degree days and winter heating degree days. By analysing these variables alone it is possible to account for around 85% of the variation in electricity demand.

The remaining 15% of variation in the half-hourly demand data mostly relates to the time of day and time of year of a specific interval. This means that the relationships between demand and the parameters listed Section 2.5.1 are not constant throughout the day or throughout the year. As a result, a unique parametric model is developed for each half-hourly interval of the year to reflect the changes to the relationships observed in the historical data. These models are combined with each other to produce a complete picture of how demand changes throughout the year. As a result of these techniques, the combined model used is described as a semi-parametric additive model.

Major industrial loads are subtracted from the demand data and modelled separately. Because these loads represent large individual projects they are not subject to the same macroeconomic and temperature drivers as the other demand types such as residential loads.

[20] Chapter 3 contains a list of all South Australian wind farms and their classifications in the NEM.

Simulation methods

Although models can be developed with a strong understanding of the changing relationships between demand and its drivers, there is always a random behavioural component to electricity use that affects the level of demand seen at any time. This randomness is incorporated into the forecasts by producing multiple simulations of what could happen in the future. These simulations are then used as the inputs for the model.

Forecast temperatures at Kent Town and Adelaide Airport are simulated from historical values using a method designed to capture the climate trends that result from typical weather systems as they move across South Australia. For each year being projected, 1,000 possible temperature profiles are produced and each of these is used to generate a half-hourly demand profile for the low, medium, and high growth scenarios. Each profile provides a summer and winter maximum demand, which are then combined and analysed as a statistical distribution that represents the likely range for maximum demand within that year. From this distribution the 10%, 50%, and 90% POE forecasts are determined. A 10% POE maximum demand forecast has a 1-in-10 chance of being met or exceeded in any year. A 50% POE forecast has a 1-in-2 chance of being met or exceeded.

Annual energy is calculated for each of the 1,000 simulations by cumulating the energy in each period. The average value is then used for each year's energy demand.

2.6 Electricity demand forecasts to 2020/21

Electricity forecasts have been produced for the three economic growth scenarios described in Section 2.4. The forecasts extend for 10 years starting with the 2011/12 financial year. For summer and winter maximum demand, the 10%, 50%, and 90% POE levels of maximum demand (MD) are presented. These have been taken from the forecast distributions, as described in Section 2.5.2.

Table 2-3 is a summary comparison of the 2010 and 2011 SASDO forecasts.

Table 2-3 — Comparison of 2010 and 2011 SASDO forecasts (medium growth scenario)

Year	Forecasts	2010 SASDO	2011 SASDO	Change
2011/12	Summer 10% POE MD	3,630 MW	3,570 MW	-60 MW (-1.7%)
	Winter 10% POE MD	2,710 MW	2,700 MW	-10 MW (-0.4%)
	Annual Energy	15,002 GWh	14,964 GWh	-38 GWh (-0.3%)
	Australian GDP Growth	3.6%	3.6%	0%
	South Australian GSP Growth	2.3%	3.9%	+1.6%
2015/16	Summer 10% POE MD	3,780 MW	3,840 MW	+60 MW (1.6%)
	Winter 10% POE MD	2,850 MW	2,850 MW	0 MW (0%)
	Annual Energy	15,506 GWh	15,800 GWh	+294 GWh (1.9%)
	Australian GDP Growth	3.1%	2.6%	-0.5%
	South Australian GSP Growth	2.7%	2.4%	-0.3%
2019/20	Summer 10% POE MD	4,010 MW	4,090 MW	80 MW (2.0 %)
	Winter 10% POE MD	3,060 MW	3,130 MW	70 MW (2.3%)
	Annual Energy	16,102 GWh	16,948 GWh	846 GWh (5.3%)
	Australian GDP Growth	2.1%	2.7%	0.6%
	South Australian GSP Growth	1.8%	2.2%	0.4%

2.6.1 Annual energy forecasts

Table 2-4 lists the annual energy forecasts for the low, medium, and high growth scenarios for the next 10 years. Annual energy is expected to grow each year of the forecast period by an average of:

- 1.1% under the low growth scenario
- 1.7% under the medium growth scenario, and
- 2.6% under the high growth scenario.

Table 2-4 — Annual energy forecasts (GWh)

Scenario	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
Low	14,807	14,956	15,067	14,976	15,171	15,397	15,567	15,738	16,031	16,221
Medium	14,964	15,180	15,513	15,569	15,800	16,131	16,363	16,716	16,947	17,195
High	15,064	15,304	15,700	16,227	16,778	17,296	17,605	17,923	18,246	18,557

Figure 2-10 shows the 2010 and 2011 annual energy forecasts for the high, medium, and low growth scenarios. The actual energy demand each year since 2000/01 is also shown. Annual energy demand has been relatively stable in South Australia for the past five years, growing only 1.4% from 2006/07 to 2010/11. The slow economic conditions in these years have contributed significantly to this trend. In the coming years it is estimated that annual energy will return closer to the patterns of growth seen before the global financial crisis, given the predicted return to steady economic growth in South Australia and the wider economy, described in Section 2.4.1.

This year's forecasts start at a lower level than last year's forecasts for all scenarios. This shift has resulted primarily from the 3% reduction in actual energy consumption for 2010/11, relative to last year's forecast for that year. The mild weather during the 2010/11 summer contributed to this reduction, by limiting the number of extended high-demand periods, as described in Section 2.3. This has affected the first few years of the new forecast but has not affected the long-term outlook significantly.

There were other factors that reduced demand in 2010/11 and may represent more fundamental shifts in energy demand patterns. These factors include:

- increasing penetration of rooftop photovoltaic systems
- increasing awareness of electricity prices
- increasing awareness of the environmental impact of electricity consumption, and
- the high Australian dollar (potentially suppressing manufacturing output in some sectors).

AEMO is aware that the level of penetration of rooftop photovoltaic systems will contribute to satisfying the state's peak demand and energy requirements. Policy and economic drivers for these systems are changing rapidly and AEMO intends to examine, in greater detail, the potential contribution from embedded generation over the next 12 months.

Despite the emergence of these demand-reducing drivers, the annual growth rate for the new medium growth forecast is considerably higher than last year, at 1.7% in the 2011 forecast, compared with 0.8% in 2010. As a result, the new forecast is higher than last year's from 2014/15 onwards. The drivers behind this higher growth include the following:

- Significant increases to the industrial load forecast from 2013/14 onwards. These have resulted from the revised mining expansion plans described in Section 2.4.1.
- Improvements to the overall economic outlook for South Australia. Average GSP growth for the 10-year period increased by 0.3%, from 2.3% last year to 2.6% in the 2011 economic outlook. For a more detailed explanation of the changes to the economic outlook, see Section 2.4.1 and Attachment A2 - Economic outlook.
- A reduction in the impact of a carbon price on retail electricity price from 2013/14 to 2014/15. These changes are described in Section 2.4.2.

The annual energy forecast for the high growth scenario is significantly lower in 2011 compared with the 2010 forecast. The main reason for this change is the reduction in the high growth scenario's assumptions for industrial load increases, which were described in Section 2.4.1. This reduction amounts to a 2,700 GWh difference between the 2010 and 2011 forecasts, in 2019/20 energy.

Figure 2-10 — Annual energy forecasts

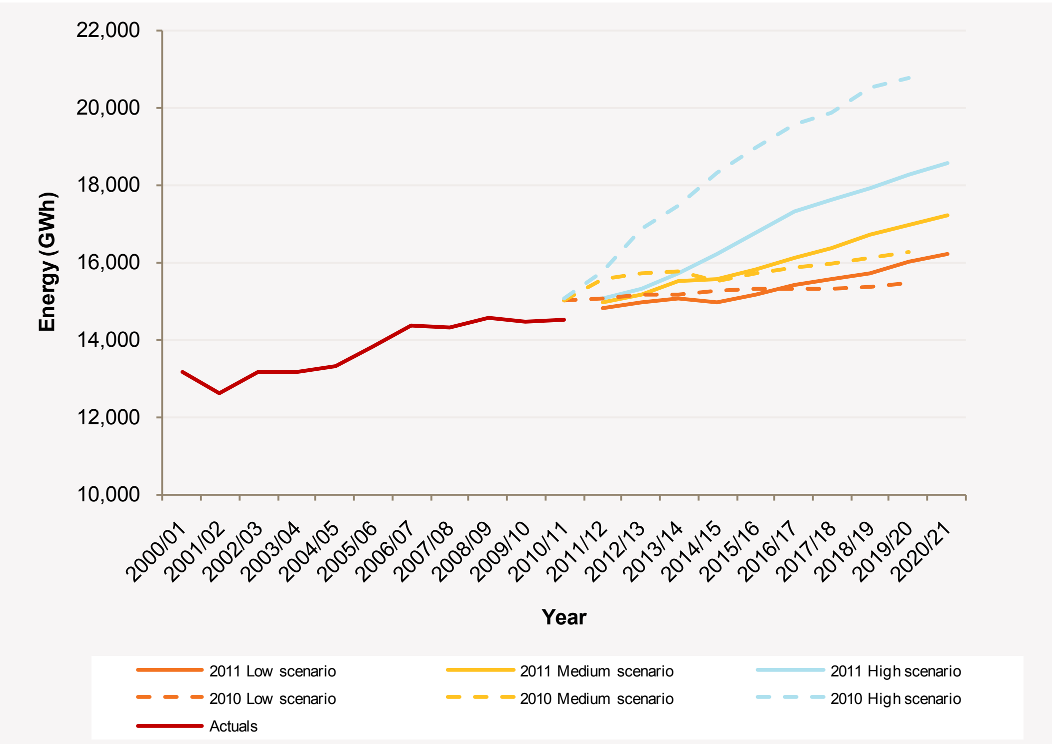


Table 2-5 provides a breakdown of the low, medium, and high growth scenario energy forecasts into customer sales, network losses, and auxiliary energy use by generators.

Table 2-5 — Annual electrical energy requirement breakdown (GWh)

	Customer sales	Plus network losses & gen. house loads	Native energy (sent out basis)	Plus gen. in-house use	Native energy (as generated basis)	Wind gen.	Other renew-able	Other non-sched.	Other sched.
Actual									
2005/06	12,140	1,067	13,207	609	13,817	765	102	22	12,319
2006/07	12,679	1,048	13,727	616	14,343	904	89	21	12,713
2007/08	12,676	995	13,671	704	14,375	1,327	75	19	12,251

	Customer sales	Plus network losses & gen. house loads	Native energy (sent out basis)	Plus gen. in-house use	Native energy (as generated basis)	Wind gen.	Other renew-able	Other non-sched.	Other sched.
2008/09	12,922	1,001	13,924	652	14,576	2,008	70	20	11,850
2009/10	12,893	980	13,873	612	14,485	2,391	69	21	11,381
2010/11 estimate	13,045	985	14,030	620	14,650	2,994	65	19	11,001
Low growth									
2011/12	13,181	989	14,169	638	14,807	3,224	85	23	11,475
2012/13	13,314	999	14,312	644	14,956	3,367	120	41	11,429
2013/14	13,412	1,006	14,418	649	15,067	3,367	120	41	11,540
2014/15	13,331	1,000	14,331	645	14,976	3,389	120	41	11,426
2015/16	13,504	1,013	14,517	653	15,171	4,229	255	41	10,646
2016/17	13,706	1,028	14,734	663	15,397	5,910	255	41	9,192
2017/18	13,857	1,039	14,897	670	15,567	7,310	255	41	7,962
2018/19	14,010	1,051	15,061	678	15,738	7,870	255	41	7,573
2019/20	14,270	1,070	15,341	690	16,031	7,870	255	41	7,865
2020/21	14,439	1,083	15,522	699	16,221	7,870	255	41	8,056
Medium growth									
2011/12	13,321	999	14,320	644	14,964	3,224	85	23	11,632
2012/13	13,513	1,013	14,526	654	15,180	3,367	120	41	11,653
2013/14	13,809	1,036	14,845	668	15,513	3,367	120	41	11,986
2014/15	13,859	1,039	14,899	670	15,569	4,229	120	41	11,179
2015/16	14,064	1,055	15,119	680	15,800	5,910	255	41	9,594
2016/17	14,359	1,077	15,436	695	16,131	7,870	255	41	7,965
2017/18	14,566	1,092	15,658	705	16,363	7,870	255	41	8,197
2018/19	14,880	1,116	15,996	720	16,716	7,870	255	41	8,551
2019/20	15,086	1,131	16,218	730	16,947	7,870	255	41	8,782
2020/21	15,307	1,148	16,455	740	17,195	7,870	255	41	9,030
High growth									
2011/12	13,410	1,006	14,415	649	15,064	3,224	85	23	11,732
2012/13	13,623	1,022	14,645	659	15,304	3,367	120	41	11,777
2013/14	13,975	1,048	15,023	676	15,700	3,367	120	41	12,172
2014/15	14,444	1,083	15,528	699	16,227	3,389	120	41	12,677
2015/16	14,935	1,120	16,055	722	16,778	4,229	255	41	12,253
2016/17	15,397	1,155	16,551	745	17,296	5,910	255	41	11,091

	Customer sales	Plus network losses & gen. house loads	Native energy (sent out basis)	Plus gen. in-house use	Native energy (as generated basis)	Wind gen.	Other renew-able	Other non-sched.	Other sched.
2017/18	15,671	1,175	16,847	758	17,605	7,310	255	41	9,999
2018/19	15,955	1,197	17,151	772	17,923	7,310	255	41	10,318
2019/20	16,242	1,218	17,460	786	18,246	7,310	255	41	10,640
2020/21	16,519	1,239	17,758	799	18,557	7,310	255	41	10,952

2.6.2 Maximum demand forecasts

Summer maximum demand forecasts

Table 2-6 lists the projected summer 10%, 50%, and 90% POE maximum demands for the next 10 years. From the start of the period, the summer 10% POE maximum demand is projected to grow each year by an average of:

- 1.3% under the low growth scenario
- 1.9% under the medium growth scenario, and
- 2.4% under the high growth scenario.

Over the period, the 10% POE maximum demand level for the medium growth scenario is projected to increase by 600 MW, from 3,570 MW in 2011/12 to 4,170 MW in 2020/21.

Table 2-6 — Summer maximum demand forecasts (MW)

POE	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
Low										
10%	3,560	3,580	3,660	3,670	3,710	3,750	3,820	3,830	3,910	3,970
50%	3,220	3,240	3,290	3,310	3,350	3,410	3,450	3,490	3,540	3,590
90%	2,960	3,000	3,050	3,050	3,100	3,130	3,170	3,210	3,250	3,300
Medium										
10%	3,570	3,630	3,700	3,780	3,840	3,920	3,960	4,030	4,090	4,170
50%	3,230	3,290	3,370	3,420	3,470	3,530	3,590	3,670	3,730	3,770
90%	2,980	3,020	3,110	3,140	3,190	3,260	3,320	3,370	3,430	3,490
High										
10%	3,600	3,650	3,740	3,850	3,950	4,060	4,110	4,210	4,270	4,390
50%	3,270	3,320	3,400	3,500	3,590	3,690	3,760	3,820	3,890	3,970
90%	3,010	3,040	3,140	3,230	3,330	3,410	3,450	3,520	3,610	3,660

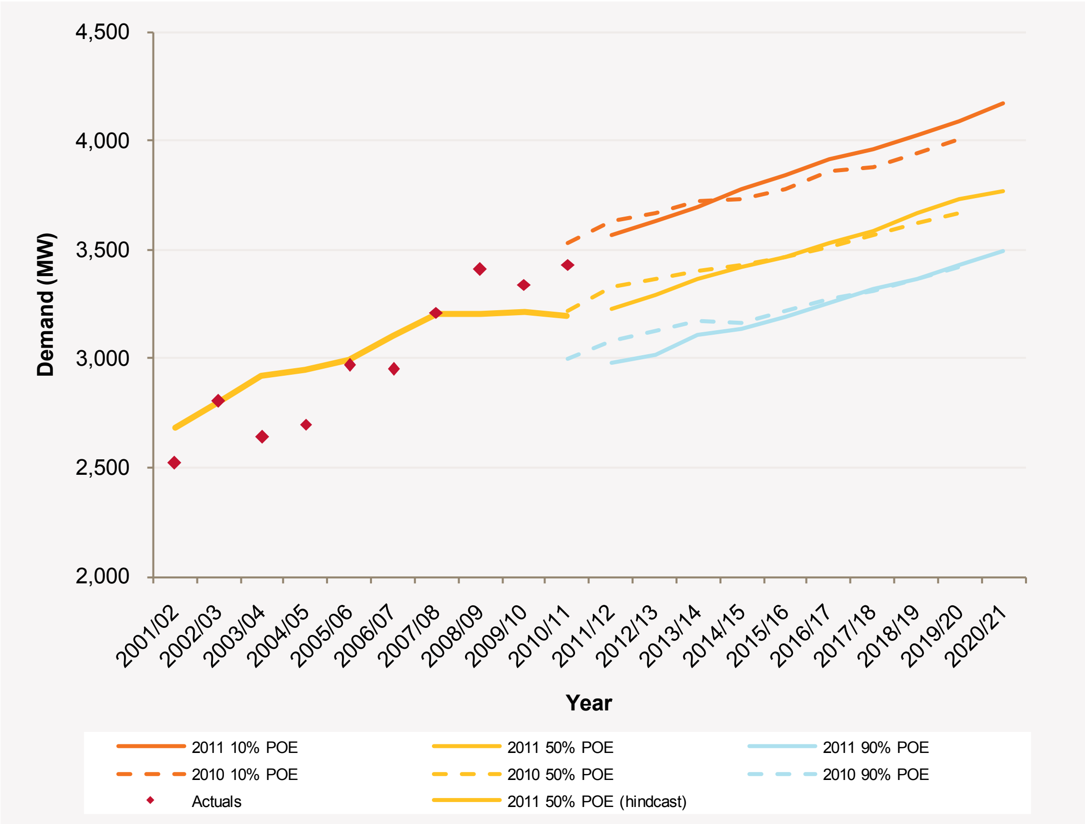
The forecasts for the medium growth scenario are shown in Figure 2-11 with the 2010 SASDO forecasts included for comparison. The figure also shows historic maximum demands, which are presented on the left side of the figure as the measured quantities that occurred at the time. These historical values do not include loads that were switched off due to factors such as outages, load shedding, or demand-side participation. Prior to being used in the forecasting model, the historic maximum demands are adjusted to account for the missing loads (as shown on the right side of the figure).

The changes to energy consumption patterns that were observed this year (described in Section 2.6.1) have reduced the summer maximum demand forecasts in the near term. This year's medium growth scenario forecast for the 2011/12 summer has been reduced by 60 MW for the 10% POE maximum demand, compared with last year.

The 2010 forecasts for the 10% POE maximum demand were relatively flat from 2013/14 to 2015/16. This is because the 2010 forecasts assumed a considerable jump in electricity prices in 2014/15, due to the introduction of a carbon price. In this year's forecasts the electricity price impact of the new carbon scheme is predicted to be less significant, as described in Section 2.4.2. The price response of consumers at times of maximum demand incorporated into the forecast has decreased accordingly. This has resulted in the new forecast showing steadier growth over the forecast period and exceeding last year's forecast from 2014/15 onwards.

The higher growth rate of the medium growth scenario forecast is also related to both the improved economic outlook compared to last year and increases to the industrial load forecasts. These changes are described in more detail in Section 2.4.1.

Figure 2-11 — Summer maximum demand forecasts (medium growth scenario)



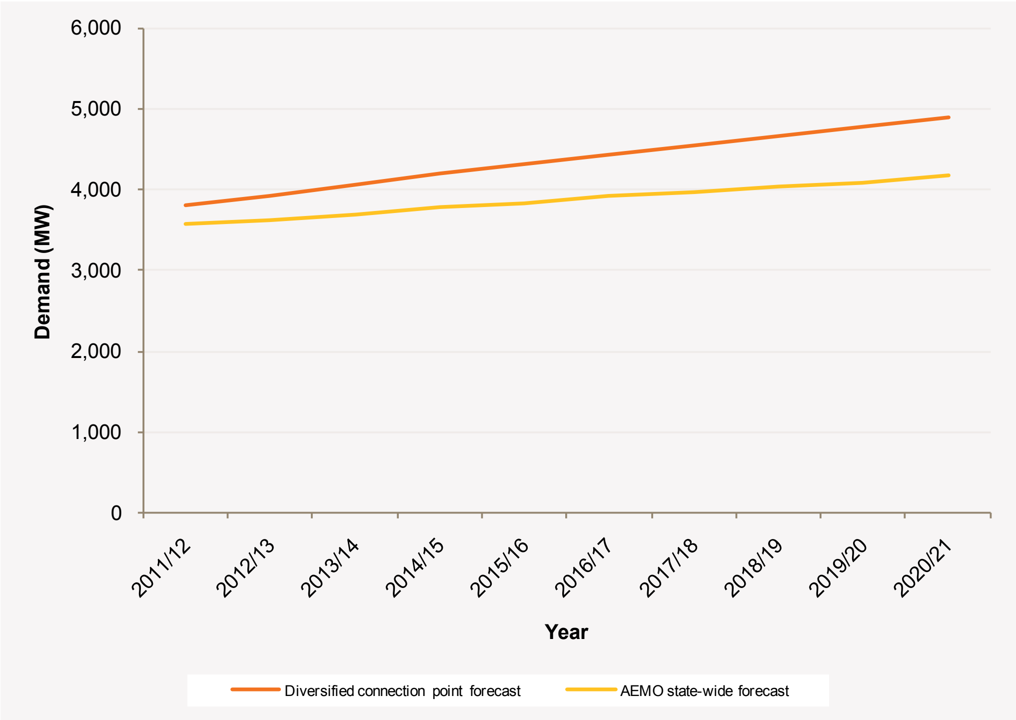
Comparison of state-wide and connection-point demand forecasts

Each year ElectraNet and ETSA Utilities prepare maximum demand forecasts over the next 10 years for each transmission connection point on the South Australian network. Although there is no formal link between state-wide and connection-point forecasts, AEMO reconciles the two sets of forecasts to ensure network planning is consistent.

The reconciliation process requires adjusting the connection-point forecasts to establish a comparable basis with the state-wide forecasts. This involves combining diversified connection-point forecasts and then scaling up this aggregate to reflect transmission losses and generator auxiliary loads. These adjustments have been based on the actual diversity that was observed between the peaking characteristics of the different connection points during recent summers.

Figure 2-12 presents the adjusted connection-point forecasts and compares these against AEMO's updated summer 10% POE maximum demand forecasts.

Figure 2-12 — Comparison of state-wide and connection-point demand forecasts



Winter maximum demand forecasts

Table 2-7 lists the forecast winter 10%, 50%, and 90% POE maximum demand for the next 10 years. From the start of the forecast period, the winter 10% POE maximum demand is projected to grow each year by an average of:

- 1.2% under the low growth scenario
- 1.8% under the medium growth scenario, and
- 2.3% under the high growth scenario.

Table 2-7 — Winter maximum demand forecasts (MW)

POE	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Low growth											
10%	2,680	2,710	2,730	2,760	2,780	2,800	2,840	2,890	2,920	2,970	3,010
50%	2,550	2,580	2,610	2,630	2,640	2,680	2,720	2,750	2,780	2,830	2,870
90%	2,430	2,460	2,480	2,520	2,520	2,550	2,590	2,620	2,640	2,700	2,740
Medium growth											
10%	2,700	2,720	2,770	2,830	2,850	2,890	2,960	3,010	3,070	3,130	3,170
50%	2,560	2,600	2,630	2,690	2,710	2,760	2,810	2,860	2,930	2,970	3,020
90%	2,450	2,480	2,520	2,570	2,570	2,630	2,690	2,740	2,790	2,840	2,890

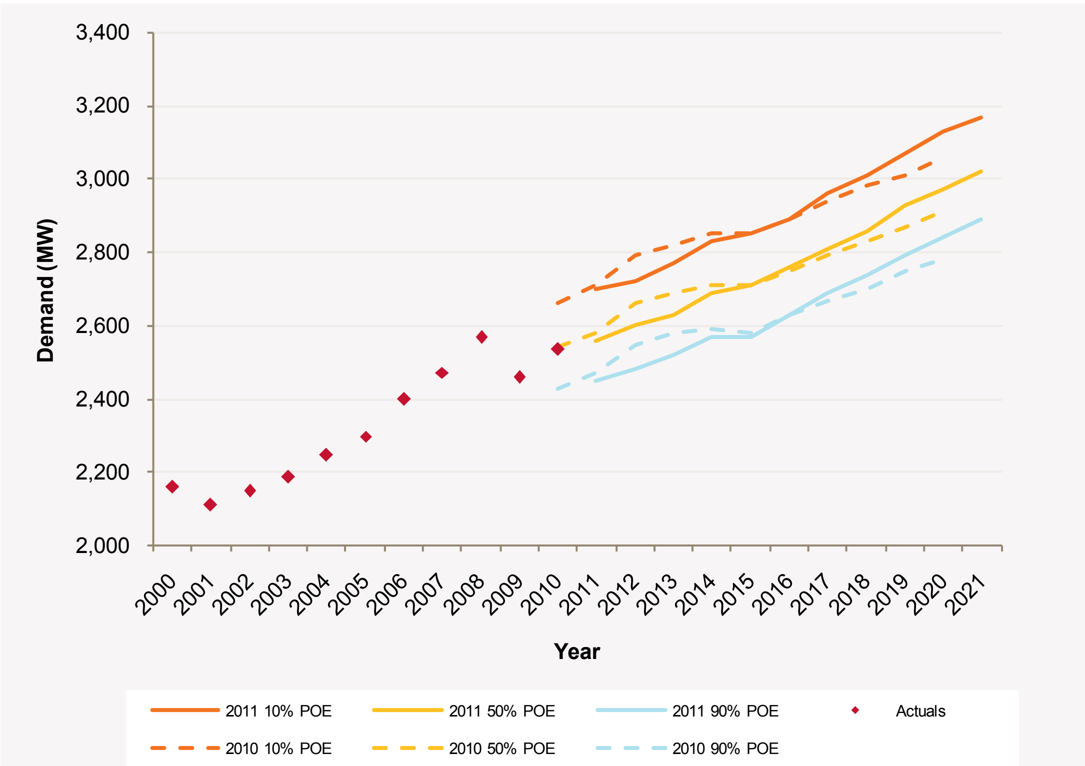
POE	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
High growth											
10%	2,700	2,760	2,790	2,860	2,930	3,010	3,090	3,150	3,210	3,290	3,330
50%	2,570	2,610	2,640	2,710	2,780	2,870	2,940	3,000	3,060	3,120	3,180
90%	2,450	2,490	2,530	2,580	2,660	2,730	2,810	2,860	2,920	2,980	3,040

Figure 2-13 shows the winter maximum demand forecasts under the medium growth scenario. The 2010 forecasts are also shown for comparison. This year's winter maximum demand forecasts are lower than last year's forecasts in the first four years. This is due to the changes in the energy consumption patterns described in Section 2.6.1, which have shifted the demand forecasts down in the near term.

According to the new forecasts, the growth in winter maximum demand over the next 10 years is predicted to be smoother than last year's forecasts suggested. This is mainly due to changed carbon price assumptions that have also affected the summer maximum demand forecasts. These changes have eliminated the reduction in maximum demand predicted last year from 2013/14 to 2014/15.

The average growth rate of the maximum demand forecasts in the medium growth scenario has increased, due to the increases in the industrial load and economic forecast assumptions described in Section 2.4.1 and Attachment A2 - Economic outlook. As a result, the 2011 forecasts exceed last year's forecasts for all POE levels in 2020.

Figure 2-13 — Winter maximum demand forecasts (medium growth scenario) (MW)



2.6.3 Non-scheduled generation forecasts

This section presents forecasts for the energy contributions of non-scheduled generation based on capacity forecasts prepared by KPMG and AEMO.

Figure 2-14 shows the energy contribution forecast of non-scheduled, scheduled, and semi-scheduled generation. The annual energy forecasts are from the medium growth scenario in Section 2.6.1. These forecasts are listed in Table 2-8.

Growth in non-scheduled and exempt generation[21] capacity over the next 10 years is expected to come from small wind generation developments and pilot projects demonstrating new renewable energy technology connected to the distribution network.

Figure 2-14 — Energy contribution forecast (medium growth scenario)

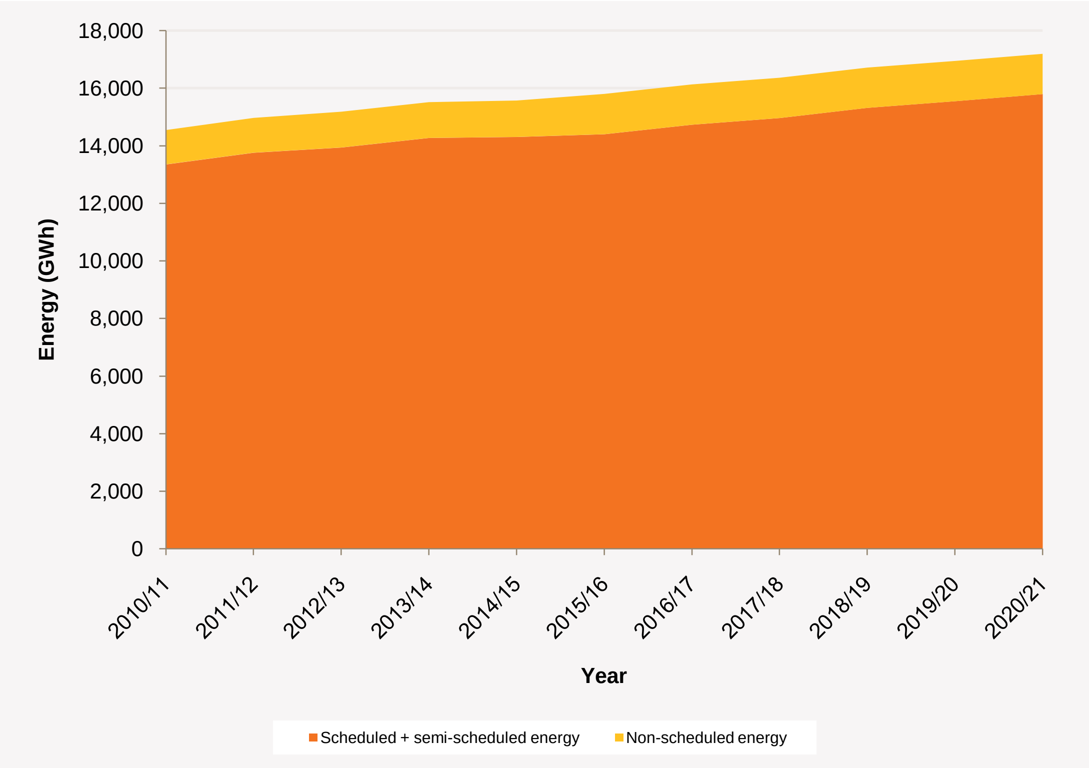


Table 2-8 — Forecasts of non-scheduled and exempt generation

Year	Capacity (MW)	Energy contribution (GWh)	Summer maximum demand contribution (MW)	Winter maximum demand contribution (MW)
2011/12	481	1,211	66	60
2012/13	489	1,246	70	64
2013/14	489	1,246	70	64
2014/15	497	1,268	70	64
2015/16	528	1,403	86	80
2016/17	528	1,403	86	80
2017/18	528	1,403	86	80

[21] See glossary.

Year	Capacity (MW)	Energy contribution (GWh)	Summer maximum demand contribution (MW)	Winter maximum demand contribution (MW)
2017/18	528	1,403	86	80
2018/19	528	1,403	86	80
2019/20	528	1,403	86	80
2020/21	528	1,403	86	80

CHAPTER 3 - GENERATION

3.1 Summary

This chapter provides information about current and prospective electricity generation projects in South Australia.

Table 3-1 — South Australian current nameplate capacity summary

	Nameplate capacity (MW)
Conventional thermal generation	3,686.8
Total wind generation	1,150.35
Total generation	4,837.15

While a generating unit's nameplate capacity provides some indication of capacity, the actual level of generation available at any particular time depends on the age of the plant, outages, wear, and temperature.

Table 3-2 lists the summer and winter capacity of the generators and wind farms in South Australia based on the latest assessment of capacity contribution. Further explanation is provided in Section 3.4.

Table 3-2 — South Australian scheduled and semi-scheduled available capacity summary[22]

	Summer 2011/12 (MW)	Winter 2012 (MW)
Conventional thermal generation	3,414.0	3,599.0
Scheduled and semi-scheduled wind generation (total/firm[23])	485.0/40.8	815.1/28.5
Total firm for the supply and demand balance	**3,454.8**	**3,627.5**

Completed projects since 2009/10 include the following:

- Synergen Power completed construction of a third generating unit with an installed capacity of 23.5 MW at Port Lincoln. This increases the open-cycle gas turbine (OCGT) plant's nameplate capacity to 73.5 MW.
- Infigen Energy/Lake Bonney Wind Power completed the 39 MW Lake Bonney Stage 3 Wind Farm.
- Roaring 40s completed construction of the 111 MW Waterloo Wind Farm.
- TRUenergy completed construction of a twelfth generating unit with a nameplate capacity of 27.5 MW at the Hallett Gas Turbine Power Station. This increases the plant's nameplate capacity to 228.3 MW.
- AGL Energy/Brown Hill North completed construction of the 132.3 MW Hallett Stage 4–North Brown Hill Wind Farm.

There is one project under construction, AGL Power Generation's 52.5 MW Hallett Stage 5–The Bluff Wind Farm. This project is scheduled for completion by December 2011.

[22] These figures are based on the regional reference for South Australian temperatures: 43 °C for summer and 11 °C for winter.
[23] Firm capacity refers to the level of generation that can be considered to be statistically reliable during 85% of peak demand periods.

3.2 Definitions and terms

3.2.1 Generation dispatch types

Under the National Electricity Rules (NER), generating systems are classified as scheduled, semi-scheduled, or non-scheduled, depending on whether or not (and how) they are dispatched.

Scheduled generation refers to any generating system with an aggregate nameplate capacity of 30 MW or more, unless it is classified as semi-scheduled, or the Australian Energy Market Operator (AEMO) is permitted to classify it as non-scheduled.

Semi-scheduled generation refers to any generating system with intermittent output (such as wind or run-of-river hydro) with an aggregate nameplate capacity of 30 MW or more. A semi-scheduled classification gives AEMO the power to limit generation output that may exceed network capabilities, but reduces the participating generator's requirement to provide dispatch information. The supply-demand outlook de-rates the installed capacities of semi-scheduled wind generators to account for firm contributions at the time of the maximum demand.

Non-scheduled generation refers to generating systems with an aggregate nameplate capacity of less than 30 MW and equal to or greater than 5 MW.

The following abbreviations are used to identify scheduled, semi-scheduled, and non-scheduled generation.

Table 3-3 — Abbreviations

Description	Abbreviation
Scheduled	S
Semi-scheduled	SS
Non-scheduled	NS

3.2.2 Commitment criteria

AEMO categorises generation as:

- existing generation, or
- committed, advanced, or publicly announced projects.

Existing generation incorporates generation that is commissioned and operating as at 30 June 2011, and requires that the operator be a registered market participant.

Committed, advanced, and publicly announced projects refer to projects under development for which AEMO has sufficient information to enable classification. Each project is assessed to identify whether it meets the criteria listed in Table 3-4. Projects meeting all five criteria are considered 'committed', those that meet three or four criteria are classified 'advanced', and those meeting two or less are classified as 'publicly announced'.

Table 3-4 — Project commitment criteria

Category	Criteria
Site	The proponent has purchased/settled/acquired land (or legal proceedings have commenced) for the construction of the proposed development.
Major components	Contracts for the supply and construction of the major components of plant or equipment (such as generating units, turbines, boilers, transmission towers, conductors, and terminal station equipment) should be finalised and executed, including any provisions for cancellation payments.

Category	Criteria
Planning consents/ construction approvals/EIS	The proponent has obtained all required planning consents, construction approvals, and licences, including completion and acceptance of any necessary environmental impact statements (EIS).
Finance	The financing arrangements for the proposal, including any debt plans, must have been concluded and contracts executed.
Final construction date set	Construction must either have commenced or a firm commencement date must have been set.

3.3 Existing South Australian generating capacity

Scheduled generation in South Australia currently comprises two sub-bituminous coal, three distillate, seven natural gas, and two dual-fuel capable power stations, with a total name-plate capacity of 3,687 MW. There are also 14 operating wind farms in the region with a total installed capacity of 1,150 MW.

Table 3-5 and Table 3-6 list the nameplate capacities and other details of power stations currently operating in South Australia, and their locations are shown in Figure 3-1.

Table 3-5 — Existing scheduled generation

Power station	Owner	Unit numbers and nameplate capacity (MW)	Installed capacity (MW)	Plant type	Fuel
Torrens A	AGL Energy	4 x 120	480	Steam sub-critical	Natural gas/fuel oil
Torrens B	AGL Energy	4 x 200	800	Steam sub-critical	Natural gas/fuel oil
Angaston	Infratil	30 x 1.67	50	Compression reciprocating engine	Diesel
Dry Creek	Synergen Power	3 x 52	156	OCGT	Natural gas
Mintaro	Synergen Power	1 x 90	90	OCGT	Natural gas
Pelican Point	Pelican Point Power	1 x 478	478	CCGT	Natural gas
Port Lincoln	Synergen Power	2 x 25 1 x 23.5	73.5	OCGT	Diesel
Snuggery	Synergen Power	3 x 21	63	OCGT	Diesel
Ladbroke Grove	Origin Energy	2 x 40	80	OCGT	Natural gas
Northern	Flinders Power	2 x 272	544	Steam sub-critical	Brown coal/fuel oil
Osborne	Origin Energy	1 x 120 1 x 60	180	CCGT/cogeneration	Natural gas
Playford	Flinders Power	4 x 60	240	Steam sub-critical	Brown coal/fuel oil
Quarantine	Origin Energy	4 x 24 1 x 128	224	OCGT	Natural gas
Hallett	TRUenergy	12 units	228.3	OCGT	Natural gas/diesel
TOTAL			**3,686.8**		

Table 3-6 — Existing wind generation

Wind farm	Owner	Unit numbers and nameplate capacity (MW)	Installed capacity (MW)	Dispatch type
Canunda	Canunda Power	23 x 2	46	NS
Cathedral Rocks	Roaring 40s/ACCIONA Energy	33 x 2	66	NS
Clements Gap	Pacific Hydro	27 x 2.1	56.7	SS
Hallett Stage 1 – Brown Hill	Palisade Investment Partner	45 x 2.1	94.5	SS
Hallett Stage – Hallett Hill	Infrastructure Capital Group	34 x 2.1	71.4	SS
Hallett Stage 4 – North Brown Hill	AGL Energy/Brown Hill North	63 x 2.1	132.3	SS
Lake Bonney Stage 1	Lake Bonney Windpower	46 x 1.75	80.5	NS
Lake Bonney Stage 2	Lake Bonney Windpower	53 x 3	159	SS
Lake Bonney Stage 3	Lake Bonney Windpower	13 x 3	39	SS
Mt Millar	Mount Millar Wind Farm	35 x 2	70	NS
Starfish Hill	Transfield Services Infrastructure Fund	23 x 1.5	34.5	NS
Snowtown Stage 1	Snowtown Wind Farm	47 x 2.1	98.7	SS
Waterloo	Roaring 40s	37 x 3	111	SS
Wattle Point	Infrastructure Capital Group	55 x 1.65	90.75	NS
TOTAL			**1,150.35**	

Figure 3-1 — Existing power station locations and nameplate capacities around South Australia

3.4 Summer and winter scheduled capacity

While generator nameplate ratings provide some indication of their realisable capacity, the actual level of generation available at any particular time will depend on a range of factors. These include the age of the plant, outages, and wear, which may affect the capacity of the generator, but the dominant factor affecting a generator's output is usually temperature.

3.4.1 Temperature effects and the regional reference temperatures

At higher temperatures, the thermal efficiency of some generators decreases and, for others such as wind farms, output may be limited to prevent overheating.

Examining the generation capacity available in South Australia under specific temperature conditions facilitates a more effective assessment of the capability of the generator under weather conditions that are frequently associated with high demand. In South Australia, the regional reference temperatures are 43 °C in summer and 11 °C in winter.

High temperatures and high demand generally coincide. These periods occur most frequently from late spring to early autumn. As a result, AEMO examines supply over an extended summer period from 1 November to 31 March, and a winter period from 1 June to 31 August.

3.4.2 Scheduled and semi-scheduled capacities

Table 3-7 and Table 3-9 list the latest summer and winter capacities for South Australian generation. Summer conditions relate to statistically predicted contribution under 10% POE maximum conditions.

Due to the intermittent nature of wind, wind generation capacities are de-rated to account for the output most likely to be available during times of maximum demand. AEMO refers to this as their firm contribution during peak periods. This is 5% of the installed capacity during summer, and 3.5% during winter. For more information about wind generation, availability, and the process for establishing the firm capacity, see section 5.4.

Table 3-8 and Table 3-10 list the total available capacity for semi-scheduled wind generation. The total available refers to the maximum amount that can be generated from the wind farms at the summer and winter reference temperatures.

South Australia has a number of large non-scheduled generating systems like the wind generation listed in Table 3-6.

Table 3-7 — Summer scheduled and firm semi-scheduled capacity by power station

Power station	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	Dispatch type
Angaston	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	S
Dry Creek	115.0	116.0	117.0	118.0	118.0	118.0	118.0	118.0	118.0	118.0	S
Hallett	198.0	198.0	198.0	198.0	198.0	198.0	198.0	198.0	198.0	198.0	S
Ladbroke Grove	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	S
Mintaro	68.0	68.0	68.0	68.0	68.0	68.0	68.0	68.0	68.0	68.0	S
Northern	544.0	544.0	544.0	544.0	544.0	544.0	544.0	544.0	544.0	544.0	S
Osborne	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	S
Pelican Point	448.0	448.0	448.0	448.0	448.0	448.0	448.0	448.0	448.0	448.0	S
Playford	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	S
Port Lincoln	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	S
Quarantine	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0	S
Snuggery	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	S
Torrens Island A	472.0	472.0	472.0	472.0	472.0	472.0	472.0	472.0	472.0	472.0	S

Power station	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	Dispatch type
Torrens Island B	780.0	780.0	780.0	780.0	780.0	780.0	780.0	780.0	780.0	780.0	S
Firm wind capacity	40.8	40.8	40.8	40.8	40.8	40.8	40.8	40.8	40.8	40.8	SS
Total	**3454.8**	**3455.8**	**3456.8**	**3457.8**	**3457.8**	**3457.8**	**3457.8**	**3457.8**	**3457.8**	**3457.8**	

Table 3-8 — Summer total available semi-scheduled capacity by power station[a]

Power station	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21
Clements Gap	56.7	56.7	56.7	56.7	56.7	56.7	56.7	56.7	56.7	56.7
Hallett 1 (Brown Hill)	58.5	58.5	58.5	58.5	58.5	58.5	58.5	58.5	58.5	58.5
Hallett 2 (Hallett Hill)	44.2	44.2	44.2	44.2	44.2	44.2	44.2	44.2	44.2	44.2
Hallett 4 (Nth Brown Hill)	81.9	81.9	81.9	81.9	81.9	81.9	81.9	81.9	81.9	81.9
Lake Bonney 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Lake Bonney 3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Snowtown	98.7	98.7	98.7	98.7	98.7	98.7	98.7	98.7	98.7	98.7
Waterloo	111.0	111.0	111.0	111.0	111.0	111.0	111.0	111.0	111.0	111.0
Hallett 5 (The Bluff)[a]	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0
Total	**485.0**	**485.0**	**485.0**	**485.0**	**485.0**	**485.0**	**485.0**	**485.0**	**485.0**	**485.0**

a. This is a committed project, hence capacity will only be available from the date of completion, scheduled around the end of 2011.

Table 3-9 — Winter scheduled and firm semi-scheduled capacity by power station

Power station	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	Dispatch type
Angaston	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	S
Dry Creek	146.0	147.0	148.0	148.0	148.0	148.0	148.0	148.0	148.0	148.0	148.0	S
Hallett	198.0	198.0	198.0	198.0	198.0	198.0	198.0	198.0	198.0	198.0	198.0	S
Ladbroke Grove	84.0	84.0	84.0	84.0	84.0	84.0	84.0	84.0	84.0	84.0	84.0	S
Mintaro	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	S
Northern	544.0	544.0	544.0	544.0	544.0	544.0	544.0	544.0	544.0	544.0	544.0	S
Osborne	190.0	190.0	190.0	190.0	190.0	190.0	190.0	190.0	190.0	190.0	190.0	S
Pelican Point	474.0	474.0	474.0	474.0	474.0	474.0	474.0	474.0	474.0	474.0	474.0	S
Playford	160.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0	S
Port Lincoln	73.0	73.0	73.0	73.0	73.0	73.0	73.0	73.0	73.0	73.0	73.0	S
Quarantine	220.0	220.0	220.0	220.0	220.0	220.0	220.0	220.0	220.0	220.0	220.0	S
Snuggery	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	S

Power station	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	Dispatch type
Torrens Island A	504.0	504.0	504.0	504.0	504.0	504.0	504.0	504.0	504.0	504.0	504.0	S
Torrens Island B	800.0	800.0	800.0	800.0	800.0	800.0	800.0	800.0	800.0	800.0	800.0	S
Firm wind capacity	28.5	28.5	28.5	28.5	28.5	28.5	28.5	28.5	28.5	28.5	28.5	SS
Total	**3627.5**	**3628.5**	**3629.5**	**3629.5**	**3629.5**	**3629.5**	**3629.5**	**3629.5**	**3629.5**	**3629.5**	**3629.5**	

Table 3-10 — Winter total available semi-scheduled capacity by power station

Power station	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Clements Gap	56.7	56.7	56.7	56.7	56.7	56.7	56.7	56.7	56.7	56.7	56.7
Hallett 1 (Brown Hill)	94.5	94.5	94.5	94.5	94.5	94.5	94.5	94.5	94.5	94.5	94.5
Hallett 2 (Hallett Hill)	71.4	71.4	71.4	71.4	71.4	71.4	71.4	71.4	71.4	71.4	71.4
Hallett 4 (Nth Brown Hill)	132.3	132.3	132.3	132.3	132.3	132.3	132.3	132.3	132.3	132.3	132.3
Lake Bonney 2	159.0	159.0	159.0	159.0	159.0	159.0	159.0	159.0	159.0	159.0	159.0
Lake Bonney 3	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0
Snowtown	98.7	98.7	98.7	98.7	98.7	98.7	98.7	98.7	98.7	98.7	98.7
Waterloo	111.0	111.0	111.0	111.0	111.0	111.0	111.0	111.0	111.0	111.0	111.0
Hallett 5 (The Bluff)[a]	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5
Total	**815.1**	**815.1**	**815.1**	**815.1**	**815.1**	**815.1**	**815.1**	**815.1**	**815.1**	**815.1**	**815.1**

a. This is a committed project.

3.4.3 Changes since 2010

Since publication of the 2010 SASDO, the following key changes have occurred:

- Infigen Energy has advised that at the regional reference temperature of 43 °C the output from the Lake Bonney Stage 2 and 3 Wind Farms will be (zero) 0 MW due to operational temperature limitations.
- Alinta Energy has advised that the output of Playford Power Station has been reduced from 240 MW to 200 MW for summer and 160 MW for winter due to a change in operational parameters.
- AGL has advised that the forecast for Torrens Island A has been revised down by 8 MW during summer, and Torrens Island B has been revised down by 20 MW for both summer and winter due to a change in the control systems and operating parameters.

3.5 Retirements/refurbishments

AEMO has not been advised of any proposed retirements before the end of the 10-year outlook period. The introduction of a carbon price may affect the timing of plant retirements.

3.6 New plant developments

3.6.1 Completed projects

Over the past financial year, the following projects have been completed in South Australia:

- Synergen Power completed construction of a third generating unit with an installed capacity of 23.5 MW at Port Lincoln. This increases the OCGT plant's nameplate capacity to 73.5 MW.
- Infigen Energy/Lake Bonney Wind Power completed the 39 MW Lake Bonney Stage 3 Wind Farm.
- Roaring 40s completed construction of the 111 MW Waterloo Wind Farm.
- TRUenergy completed construction of a twelfth generating unit with a nameplate capacity of 27.5 MW at the Hallett Gas Turbine Power Station. This increases the plant's nameplate capacity to 228.3 MW.
- AGL Energy/Brown Hill North completed construction of the 132.3 MW Hallett Stage 4 – North Brown Hill Wind Farm.

3.6.2 Projects under construction

There is currently only one project that is committed and under construction in South Australia. AGL Power Generation has commenced construction of the 52.5 MW Hallett Stage 5 – The Bluff Wind Farm. This project is scheduled for completion by December 2011. For more information about this plant, see Table 3-11.

3.6.3 New projects

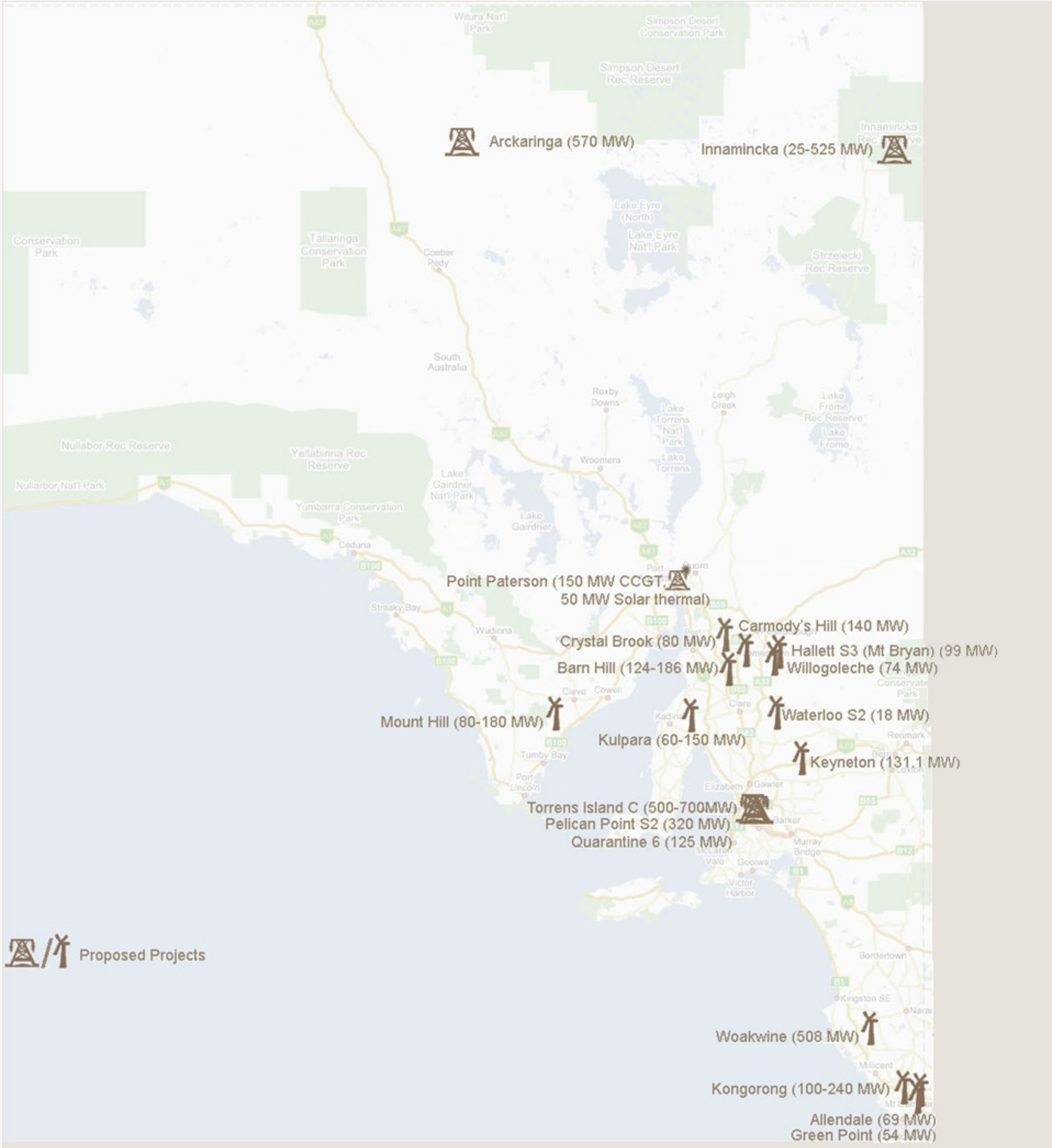
New generation investment has been slower in 2011, with the majority of projects involving renewable or peaking generation, and still in the early development stage. Several proponents have undertaken substantial feasibility work, and cited delays in investment due to current energy demand, uncertainty with regard to environmental policies, and/or other market conditions.

The Hallett Stage 5 – The Bluff Wind Farm is the only committed project in South Australia, and AEMO has not been informed of any advanced projects.

Table 3-12 summarises new generation proposals for South Australia that have been classified as publicly announced.

A number of projects are not listed, being regarded by proponents as confidential, either due to being at a very early stage of development, changes in the project's details, or a company or project sale process that is currently underway. As a result, a number of projects listed last year have not been included this year.

Figure 3-2 — Location and nameplate capacities of new plant developments



Allendale Wind Farm: ACCIONA Energy is proposing a new wind farm at Allendale, seven kilometres south of Mt Gambier in South East South Australia. In March 2010, Grant District Council's development assessment panel approved plans to install 46 turbines at the site, and an appeal was subsequently lodged with the Environment, Resources and Development Court. The Court has upheld the appeal against the development, but an appeal to the Supreme Court may still occur.[24]

[24] http://www.borderwatch.com.au/archives/9443.

Arckaringa: Altona Energy and China National Offshore Oil Corporation's New Energy Investment Company are joint venture partners in the Arckaringa Project, located approximately 120 kilometres north of Coober Pedy. The generation component is part of an integrated gasification and variable fuels/power production process. It has a planned installed capacity of 1,140 MW, comprising two gas turbines and two steam turbines, with approx 570 MW available for export to the National Electricity Market (NEM) should it be extended to this project.

Barn Hill Wind Farm: In 2010, AGL Energy acquired the right to install up to 62 turbines (estimated capacity between 124 MW and 186 MW) at Barn Hill from Transfield Services. The wind farm is to be located 170 kilometres north of Adelaide near the settlement of Red Hill.

Carmodys Hill Wind Farm: Pacific Hydro's proposed 140 MW wind farm at Carmody's Hill is located on the ridgeline to the east of Georgetown, running approximately 18 kilometres north from Mt Misery.

Cherokee Power Station: Investec, on behalf of Tungkillo Powerco Pty. Ltd., have publicly announced their intention to build a peaking power station approximately 8 kilometres south west of Mannum. The first stage of the project is to build a 250 MW OCGT generating unit with long term plans to increase the capacity of the plant to up to 1000 MW in 2021.

Collaby Hill/Crystal Brook Wind Farm: Origin Energy's proposed Crystal Brook Wind Farm (previously known as Collaby Hill) is located on an 8 kilometres strip of farming land between Crystal Brook and Warnertown. The project is still in its feasibility stage, and Origin plans to conduct further detailed studies and work with landholders and the community to develop the wind farm proposal, with a possible development application later in 2011.

Green Point Wind Farm: Wind Prospect's proposed Green Point Wind Farm is to be located in South Australia's south eastern region, 15 kilometres east of Port McDonald, adjacent to the Victorian border.

Hallett Stage 3 – Mt Bryan Wind Farm: AGL Energy's proposed development covers a ridge spanning approximately 11 kilometres directly west of the township of Mount Bryan. Comprising 33 turbines, the proposed wind farm was the subject of an appeal before the Environment, Resources and Development Court. In December 2010, the Court confirmed the Council's development plan consent, subject to some minor variations to the conditions imposed.

Innamincka: Following the Habenero 3 well control incident in 2010, Geodynamics installed new casing liners into the Jolokia 1 well. Made from a material independently assured to withstand the chemistry of the fluid present, Geodynamics expects this to be the technical solution to the issues experienced at Habenero 3. Origin Energy and Geodynamics have formed a 50/50 partnership to undertake further exploration. The Shallows program commenced with the drilling of Celsius 1 to a target depth of 2,360 metres. Over the next few years, Geodynamics intends to reproduce a man-made heat exchanger, drill Habenero 4 and 5, and demonstrate a 1 MW plant.

Keyneton Wind Farm: Pacific Hydro is proposing to develop a wind farm at Keyneton, six kilometres west of Sedan and 10 kilometres south east of Angaston. The site runs approximately 18 kilometres north to south. The proposal consists of up to 57 turbines with a total capacity around 131 MW.

Kongorong Wind Farm: Transfield Services is developing a 100 MW to 240 MW wind farm project at Kongorong, approximately 20 kilometres south west of Mount Gambier.

Kulpara Wind Farm: Transfield Services is proposing a 60 MW to150 MW wind farm at Kulpara, 16 kilometres north west of Port Wakefield at the top of the Yorke Peninsula.

Mount Hill Wind Farm: Transfield Services is proposing an 80 MW to 180 MW wind farm at Mount Hill, located near Butler, 80 kilometres north east of Port Lincoln on the Eyre Peninsula.

Pelican Point S2: International Power has proposed an expansion of the Pelican Point power station. The Stage 2 proposal includes two 160 MW OCGT generating units.

Point Patterson: Aquasol Infrastructure is proposing a 50 MW solar thermal, and 150 MW combined-cycle power generation plant at Point Patterson, 12 kilometres south of Port Augusta, on the eastern side of the upper Spencer Gulf. The plant is part of a larger proposal featuring a 1.75 square kilometre mirror field with a desalination plant, solar thermal storage, combined-cycle gas turbine, and other operating equipment contained in a small adjacent area.

Quarantine 6: Origin Energy is proposing another 125 MW expansion to its existing Quarantine Power Plant.

Torrens Island C: AGL Energy is proposing an expansion to its Torrens Island power stations, involving two major components that include:

- a power station expansion of up to up to 700 MW of additional peaking generation, involving either four ‘E’ class gas turbines with a nominal capacity of between 120 MW and 190 MW each, or two ‘F’ class gas turbines with a nominal capacity of between 200 MW and 300 MW each, and
- a gas storage facility, comprising a Liquefied Natural Gas (LNG) production plant, storage tank, and re-gasification units that convert LNG to pipeline-quality gas.

The timing of the expansion is subject to market demand and yet to be determined. Based on current market demand, however, it is expected within the next 2-3 years.

Waterloo expansion: Roaring 40s is proposing to increase the capacity of its wind farm at Waterloo by an additional 18 MW.

Willogeleche Wind Farm: International Power has proposed a 74 MW wind farm located west of the township of Hallett, 200 kilometres north of Adelaide in the mid-north of South Australia.

Woakwine Wind Farm: Infigen Energy is proposing to construct a 420 MW wind farm at Woakwine Range in the south east, near Millicent and close to Infigen’s existing Lake Bonney wind projects.

Table 3-11 — Generation projects, committed and under construction

Project	Owner	Unit ID	Fuel	Technology	Land	Equip	Plan	Finance	Date	Construction start date	Nameplate capacity (MW)	Unit status	Dispatch type
Hallett 5 (The Bluff) WF	AGL Power Generation Pty Limited	1-25	Wind	Wind–Onshore	✓	✓	✓	✓	✓	Under construction	52.5	Committed	SS

Table 3-12 — Publicly announced generation projects

Project	Owner	Unit ID	Fuel	Technology	Land	Equip	Plan	Finance	Date	Construction start date	Nameplate capacity (MW)	Unit status	Dispatch type
Allendale	ACCIONA Energy	1-46	Wind	Wind–Onshore	✓					1/09/2013	69	Publicly announced	SS
Arckaringa	Arckaringa Joint Venture	1-2	Black Coal/Diesel	IGCC						TBA	570[a]	Publicly announced	S
Barn Hill	Barn HIll Wind Farm Pty Ltd	62	Wind	Wind–Onshore	✓					TBA	124-186	Publicly announced	SS
Carmodys Hill	Pacific Hydro Pty Ltd	1-70	Wind	Wind–Onshore						TBA	140	Publicly announced	SS
Cherokee Power Station	Tunkillo Powerco Pty Ltd	1	Natural Gas	OCGT						31/12/2013	250	Publicly announced	S
Collaby Hill/Crystal Brook	Origin Energy	1-40	Wind	Wind–Onshore						1/01/2014	80	Publicly announced	SS
Green Point	Wind Prospect Pty Ltd	1-18	Wind	Wind–Onshore						TBA	54	Publicly announced	SS
Hallett 3 (Mt Bryan) WF	AGL Energy Limited	1-33	Wind	Wind–Onshore	✓					TBA	99	Publicly announced	SS

Project	Owner	Unit ID	Fuel	Technology	Land	Equip	Plan	Finance	Date	Construction start date	Nameplate capacity (MW)	Unit status	Dispatch type
Innamincka	Geodynamics Limited/Origin Energy Geothermal Pty Ltd (Joint Venture)	1	Geological heat	Geothermal HDR-Binary cycle	✓					1/07/2013	25	Publicly announced	S
		2-3	Geological heat	Geothermal HDR-Binary cycle	✓					30/06/2015	100	Publicly announced	S
		4-7	Geological heat	Geothermal HDR-Binary cycle	✓					30/06/2016	200	Publicly announced	S
		8-11	Geological heat	Geothermal HDR-Binary cycle	✓					30/06/2017	200	Publicly announced	S
Keyneton	Pacific Hydro Pty Ltd	1-57	Wind	Wind–Onshore						TBA	131.1	Publicly announced	SS
Kongorong	Transfield Services	Station	Wind	Wind–Onshore						TBA	100-240	Publicly announced	SS
Kulpara	Transfield Services	Station	Wind	Wind–Onshore						TBA	60-150	Publicly announced	SS
Mount Hill	Transfield Services	Station	Wind	Wind–Onshore						TBA	80-180	Publicly announced	SS
Pelican Point S2	Pelican Point Power Ltd	1-2	Natural Gas	OCGT	✓					TBA	320	Publicly announced	S
Point Paterson	Acquasol Infrastructure Pty Ltd	CCGT Units	Natural Gas	CCGT						1/02/2012	150	Publicly announced	S
		Solar Units	Solar	Solar Thermal						1/02/2012	50	Publicly announced	S
Quarantine 6	Origin Energy	6	Natural Gas	OCGT						1/10/2013	125	Publicly Announced	S
Torrens Island C	AGL Energy Ltd	Station	Natural Gas	OCGT	✓					TBA	500-750	Publicly announced	S

Project	Owner	Unit ID	Fuel	Technology	Land	Equip	Plan	Finance	Date	Construction start date	Nameplate capacity (MW)	Unit status	Dispatch type
Waterloo expansion	Roaring 40s Renewable Energy Pty Ltd	38-42	Wind	Wind–Onshore	✓					TBA	18	Publicly announced	SS
Willogoleche	Willogoleche Power Pty Ltd	1-25	Wind	Wind–Onshore						TBA	74	Publicly announced	SS
Woakwine	Infigen Energy	Station	Wind	Wind–Onshore						1/10/2013	508	Publicly announced	SS

[This page is left blank intentionally]

CHAPTER 4 - FUEL SUPPLY

4.1 Summary

This chapter presents information about the range of available fuel sources within South Australia for electricity generation, their usage history and background, fuel and resource availability, and greenhouse gas emissions.

Wind generation continues to increase in terms of installed capacity and the percentage of total energy produced, and is primarily displacing gas fired generation and to a lesser degree coal-fired generation.

Coal supplies from the Leigh Creek coal mine are limited. However the economic reserves at the mine are likely to be adequate for approximately another 15 years. Other South Australian coal fields of similar quality have been identified as potential fuel options, but these resources have not yet been fully proven and present development risks. Coal imports from other states present another possible option.

Gas production in South Australia currently represents 15% of the total gas production in Eastern and South Eastern Australia. Although some gas is exported from South Australia, on balance the region is a net gas importer. For the year ending December 2010, 2P gas reserves reported for the Cooper and Eromanga basins increased by 15%, although gas production from these basins continues to decline, and in 2010 was approximately a third of the peak rate in 2001. The Short-Term Trading Market for Gas commenced on 1 September 2010, facilitating gas trading via market-driven daily prices.

While a number of liquid-fuelled generators have been built in South Australia, they provide only a small percentage of total energy generation.

The fuel situation in South Australia is good with no short to medium-term issues in ether gas or coal supplies.

South Australia has been identified as having significant prospects for geothermal energy, and work is underway to investigate both ‘enhanced geothermal systems’ and ‘hot sedimentary aquifer’ opportunities.[25] Most generation investment has been in wind, and many more high-quality wind resource sites still exist. There has also been an increase in the installation of small scale photovoltaic systems to exploit the region’s solar resources.

Emissions of greenhouse gasses from the energy sector continue to fall slowly, as the percentage of wind generation rises and the contribution from imported energy falls.

4.2 Fuel use history and background

The National Electricity Market (NEM) relies on coal for approximately 77% of electricity generation, while 12% of generation comes from gas powered generation. Hydroelectricity’s share has grown to 8% (following the end of the prolonged drought), and wind generation has grown to nearly 2.5%. Small energy contributions derive from other fuel sources including liquid fuels, biomass, and solar power.

In 2010/11, South Australia relied on coal for approximately 30% of electricity generation, gas for 44%, and wind for 20%. The remainder was sourced from imports, solar generation, and small amounts of diesel-fired generation.

Figure 4-1 shows the generation trend over a number of years, indicating a decrease in the contribution from fossil-fuels, and an increase in wind. Supply via the interconnector is shown as net imports.

25 More information on these geothermal systems is available in Appendix B -Technology discussion.

Figure 4-1 — South Australian energy by technology

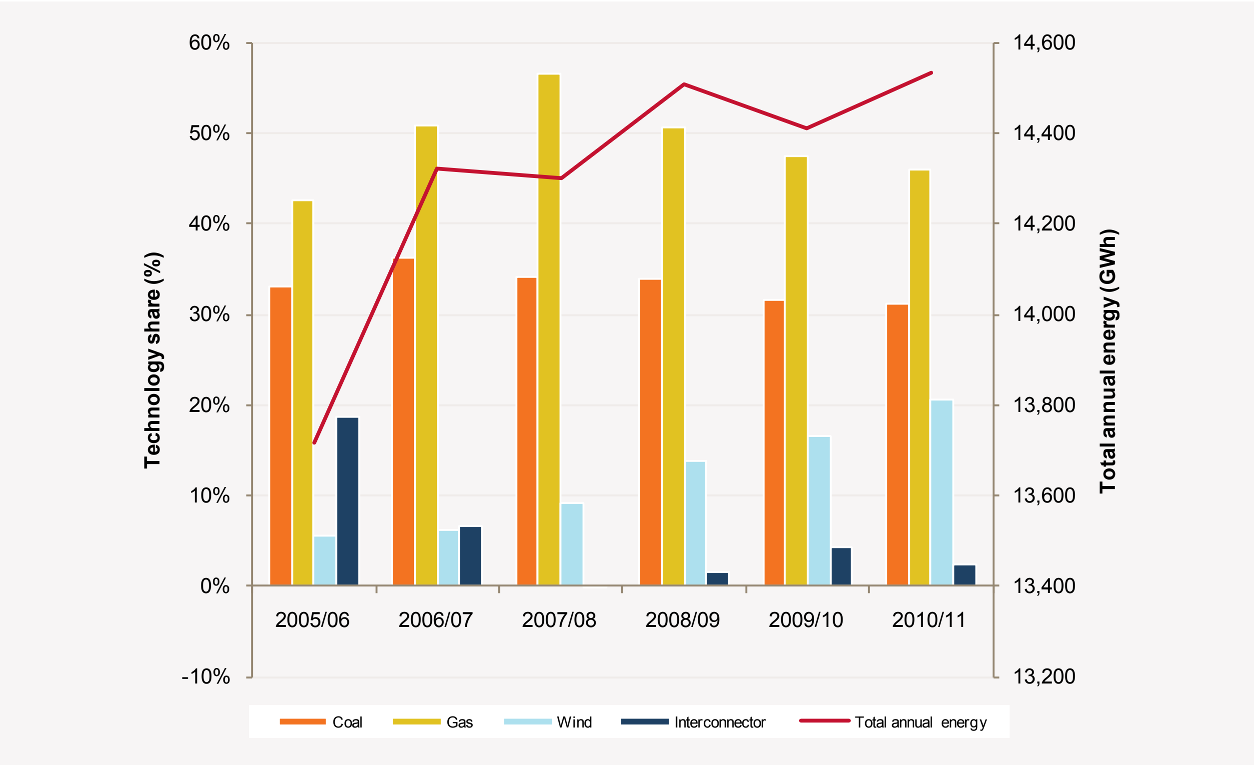
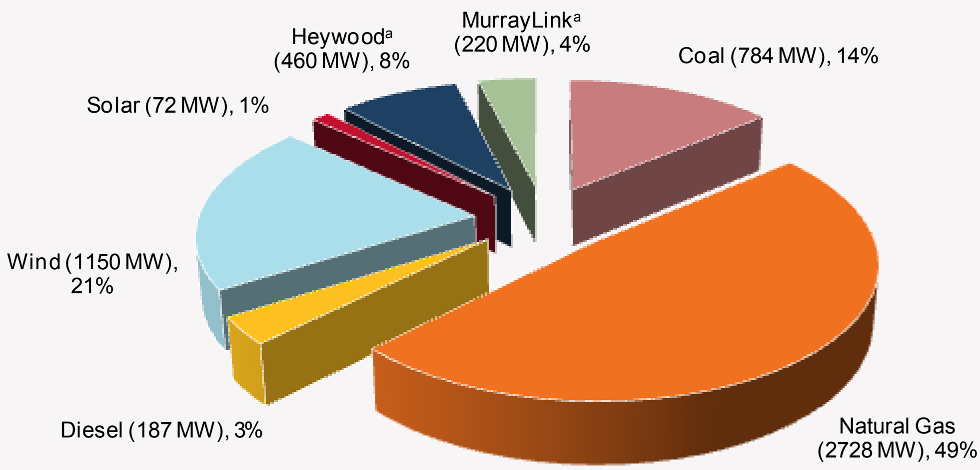


Figure 4-2 shows the relative percentage of total South Australian installed capacity by energy source for 2010/11.

The figure demonstrates the state's dependence on natural gas. Approximately 49% of the installed capacity is from gas powered generation, and the installed capacity of wind increased to 21%. As with total electricity generation, wind's share of the state's total installed capacity is rising.

Figure 4-2 — South Australian installed capacity by fuel source (2010/11)



[a] South Australia to Victoria interconnectors.

4.2.1 Greenhouse gas emissions

Greenhouse gases include carbon dioxide, methane, nitrous oxide, perfluorocarbons, hydrofluorocarbons, and sulphur hexafluoride. Different gasses have different global warming potential. Their impact is measured relative to carbon dioxide, and they are collectively referred to as carbon dioxide equivalent (CO2-e) emissions.

Figure 4-3 shows CO2-e emissions from South Australian electricity generation, and the emissions associated with electricity imported into South Australia from the rest of the NEM. There has been a decline in emissions over the last few years primarily due to increased wind generation in the state. The net import from other regions has also decreased significantly from 2005/06.

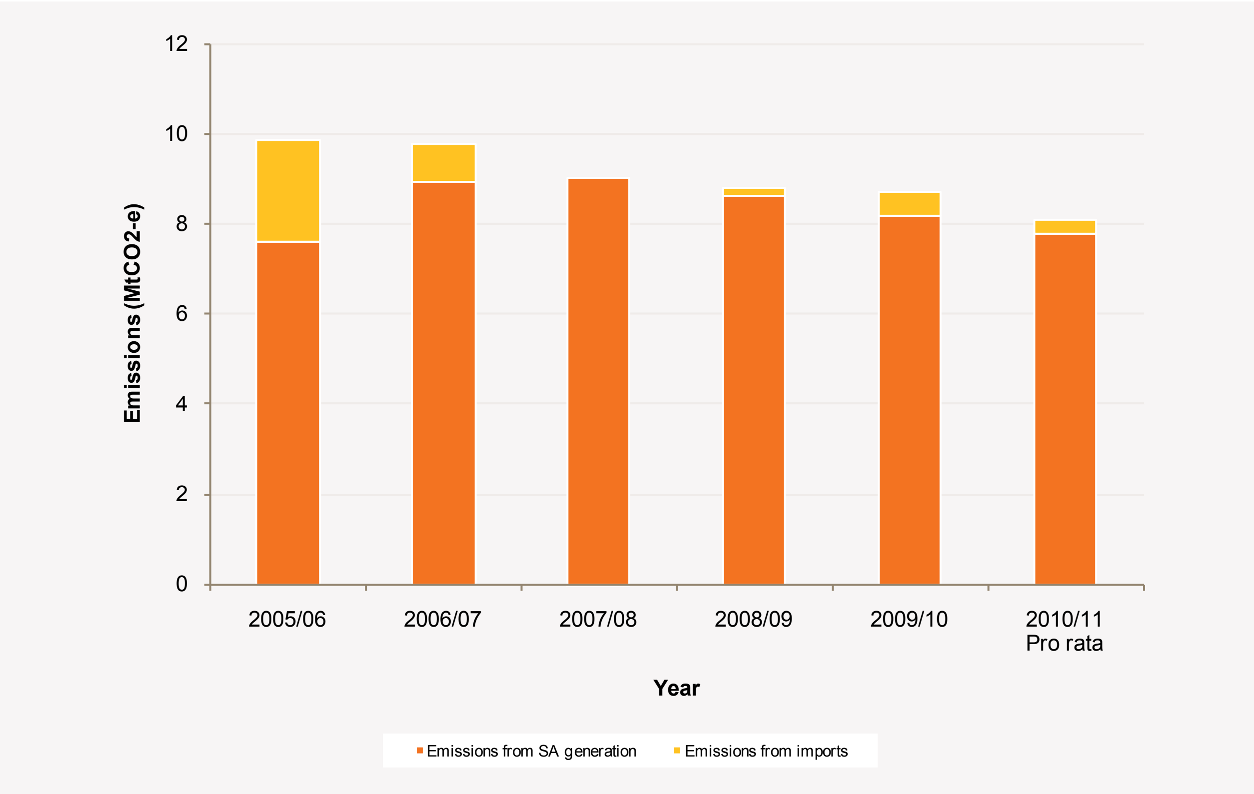
In terms of emissions calculations:

- local estimates apply known generating system heat rates, actual half-hourly generation and emission rates for the fuels used, including South Australian energy exports (because exported energy is generated within the state), and
- estimates for other states are calculated half-hourly, and the average emission level applied to imports into South Australia. This assumes that import emission levels are the same as the NEM average (excluding South Australia).

The CO2-e emissions calculations use emissions factors published in the Australian National Greenhouse Gas inventory.[26]

[26] Department of Climate Change and Energy Efficiency, http://www.climatechange.gov.au/publications/greenhouse-acctg/national-greenhouse-gas-inventory-2009.aspx.

Figure 4-3 — South Australian annual emissions



4.3 Fuel and resource availability

This section provides an overview of the availability of the primary fuels in South Australia, highlighting:

- that coal supplies are limited (while identifying a number of options for future coal supplies for the coal-fired generators at Port Augusta)
- the availability of gas resources within South Australia, and the infrastructure in place to supply gas into South Australia from Queensland and Victoria, and
- renewable energy resources.

While this information is based on the current policy environment, the assessment of the available reserves and resources in the mining industry relates to the economically recoverable quantities of fuel. Future policies that may put a price on carbon emissions are likely to alter the economic viability of different types of generation and the resources that are developed and utilised. Specifically, the introduction of a carbon price may affect the relative costs of fuel for gas and coal-fired generators.

4.3.1 Coal availability in South Australia

South Australia has two coal-fired generators, Northern Power Station and Playford B Power Station, which are located at Port Augusta, 320 kilometres north of Adelaide, and are supplied from the Leigh Creek open cut coal mine (comprising the Copley, North Field, and Telford Basins) via a 280 kilometre rail line.

The Leigh Creek coal mine is the state’s only operating coal mine comprising a number of seams of sub-bituminous black coal, 567 kilometres north of Adelaide. Leigh Creek coal is of a lower quality than New South Wales or Queensland black coal, but a higher quality than Victorian brown coal. The Leigh Creek mine is currently limited to the main and upper series coal seams of Lobe B in the Telford Basin, with the potential to access the lower seam in the future. While there are approximately 150 million tonnes of inferred resources at Leigh Creek, much of this is not economically recoverable.

AEMO commissioned a report to investigate the situation for the supply to these power stations and what options might be viable should the Leigh Creek mine cease to be an economic source of coal.[27]

This report provided estimates of the economically recoverable coal resources at Leigh Creek that include the:

- upper seam, currently estimated at 6 million tonnes, with an annual usage of around 1.2 million tonnes
- main seam, currently between 14.5 million tonnes and 17.5 million tonnes, with an annual usage of around 1.4 million tonnes, and
- lower seam, currently estimated at between 32 million tonnes and 62 million tonnes, but not currently mined.

The report indicates that Northern and Playford Power Stations consume approximately 3.8 million tonnes of coal annually. With between 50 and 85 million tonnes remaining at the Leigh Creek mine, the remaining life would be approximately 15 years depending on the operating regime of the power stations.

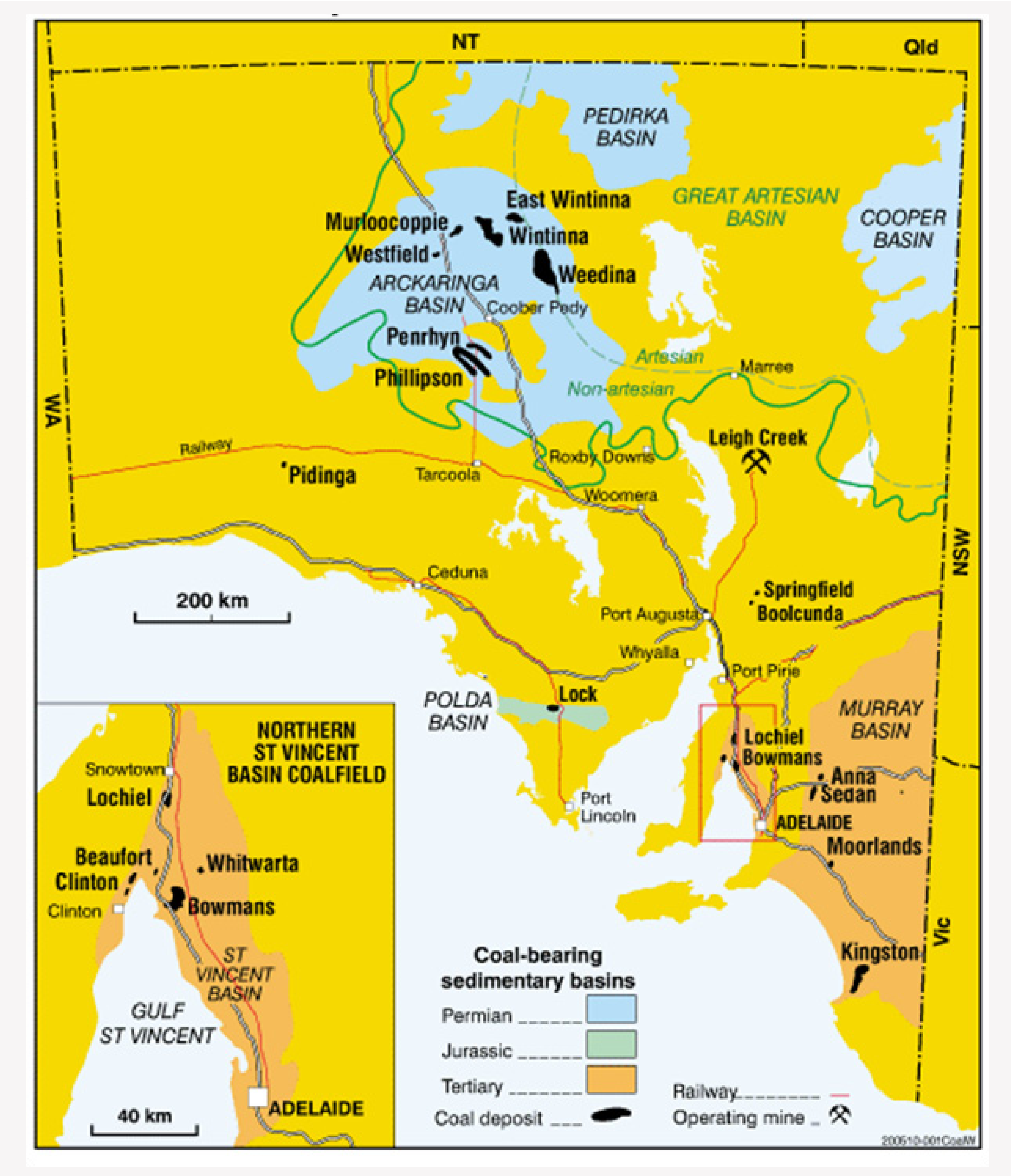
The report further indicates options are available for alternative coal supplies for Northern and Playford Power Stations into the future. These include new mine development in South Australia, and coal imports from Western Australia, New South Wales, or from overseas. The owner of the power stations, Alinta Energy, is reported to be investigating alternate coal supplies within South Australia.[28]

Figure 4-4 published by the South Australian Department of Primary Industries and Resources (PIR), and Table 4-1 show the range of South Australian coal resources.

[27] CQ Partners, "Leigh Creek Life Study", March 2011.

[28] http://www.adelaidenow.com.au/business/alinta-seeks-coal-to-keep-power-plant-going/story-e6frede3-1226038658107, accessed 16 May 2011.

Figure 4-4 — South Australian coal deposits[29]



29 http://www.pir.sa.gov.au/minerals/geology/mineral_resources/commodities/coal accessed 20 April 2011.

Table 4-1 — South Australian coal resources[30]

Deposit	Geological age	Rank	Coal tonnage		Proximate analysis				Heat value (MJ/kg)	Impurities		
			Measured Indicated (million tonnes)	Inferred (million tonnes)	Moisture (%)	Ash (%)	Volatile manner (%)	Fixed carbon (%)		Total sulphur (%)	Chlorine (%)	Sodium-in-ash (%)
Wintinna	Permian	Sub-bituminous	1,870	2,270	38	6	23	33	17.5	1.1	0.04	2
East Wintinna			975	1,200	38	5	23	34	17.6	0.5	0.01	1
Murioocoppie			940	2,690	37	9	22	32	16.1	1.8	-	2
Westfield			313	470	38	6	22	34	16.7	2.7	0.06	1
Weedina			1,200	6000	38	8	22	32	16.5	0.5	0.04	1
Philipson			-	5000	35	11	25	29	16.2	0.7	1.24	12
Copley Basin Lobe A	Triassic		11	-	37	12	20	31	15.2	2.9	-	-
Copley Basin Lobe E			21	2	32	22	24	34	12.7	3.4	0.07	-
Copley Basin Lobe C			12	-	29	22	22	27	13.3	3.0	-	-
Telford Basin Lobe B			150	350	31	13	21	35	15.2	0.5	0.30	4
Lock	Jurassic		320	-	26	23	30	21	14.6	0.4	0.23	2
Bowmans	Tertiary	Lignite	1,250	350	56	6	21	17	10.6	2.2	0.67	11
Clinton			340	440	53	9	18	20	9.4	1.9	-	16
Beaufort			255	45	-	-	-	-	-	-	-	-
Whitwarta			145	185	55	12	19	14	9.4	2.6	-	9
Lochiel			625	-	61	6	19	14	9.1	1.1	0.20	7
Kingston			985	-	53	7	22	18	10.6	1.5	0.11	6
Anna			58	-	54	11	21	14	9.9	1.8	-	2
Sedan			184	-	58	9	19	14	9.4	2.3	0.08	3
Moorlands			32	-	55	9	18	18	9.9	1.8	0.14	3

The report to AEMO[31] identifies three sources of coal within South Australia at Lake Phillipson, the Polda Basin (Lock), and Wintinna, and investigated for use by the current South Australian coal-fired power stations. Options to import coal from Western Australia and the New South Wales Ulan region are also considered.

30 Reproduced from Primary Industries and Resources SA. PIRSA Minerals. http://www.pir.sa.gov.au/minerals/geology/mineral_resources/commodities/coal accessed 20 April 2011.

31 CQ Partners, "Leigh Creek Life Study", March 2011.

South Australia – Lake Phillipson

This deposit is high in sodium and chlorides, and will require washing to bring it up to specification for use in the power station. Work is being undertaken to determine feasibility, and while the results are promising, the limited water supplies could cause washing costs to be high.

South Australia – Polda Basin (Lock)

This deposit appears to be suitable for use, and one seam in particular has been identified as having economic potential. Additional boreholes will be needed to prove up the resources in this region. The deposit is remote from the power station and significant capital will be needed to deliver the coal. Options for this include:

- utilisation of the narrow gauge railway line to Port Lincoln followed by tug and barge to Port Augusta, and the construction of suitable unloading and handling facilities at Port Augusta
- construction of a new standard gauge railway line near to Whyalla, and use of the standard gauge line to Northern Power Station, and
- construction of a 260 kilometre conveyer belt from the mine to the power station stockpile.

South Australia – Wintinna

Wintinna coal has been previously investigated as a source for South Australian coal-fired power stations, but was rejected due to its remoteness and mining costs. Altona Energy and China National Offshore Oil Corporation's New Energy Investment Company are joint venture partners investigating options to develop the site.[32] The project is known as the Arkaringa Project (more information on the generation proposal at Arkaringa is available in Section 3.6.3).

Western Australia

The Collie coal fields produce coal that may be suitable for the South Australian coal-fired power stations, but the sale of Griffith Coal in Western Australia to Lanco Infratech from India is likely to tie coal from the Collie mines to projects in India. Export from the Westfarmers Western Australian coal mine has been minimal to date, and the high transport costs are anticipated to make it unviable as a supplier to South Australia.

New South Wales – the Ulan region

Coal from the Ulan region can be shipped to South Australian coal-fired power stations on a rail line via Broken Hill. Sending coal west from Ulan avoids the congestion faced by export coals in New South Wales. This coal has a higher heating value than Leigh Creek coal, and to be usable requires blending with lower-quality Leigh Creek lower-series coal, or modifications to the power stations' boilers.

Evaluation of coal supply options

Due to uncertainties surrounding the cost and timing of alternate coal supply options, it is difficult to develop a solid coal price forecast. High-level estimates, however, show that the price of coal to supply South Australian coal-fired power stations will rise depending on the alternatives considered.

The implementation of a carbon tax or emissions trading scheme will also impact these options differently, the higher heating value coals attracting less carbon costs per megawatt hour of generation, but potentially being off-set by higher, long-distance transport costs.

4.3.2 Gas availability in South Australia

South Australian gas consumption was approximately105 PJ in 2010, 61% of which was used for electricity generation. Demand is generally higher in the winter months in South Australia, as gas is used for both heating and electricity generation. However, peak daily demand can occur during summer heat waves, when more gas powered electricity generation is needed to meet demand.

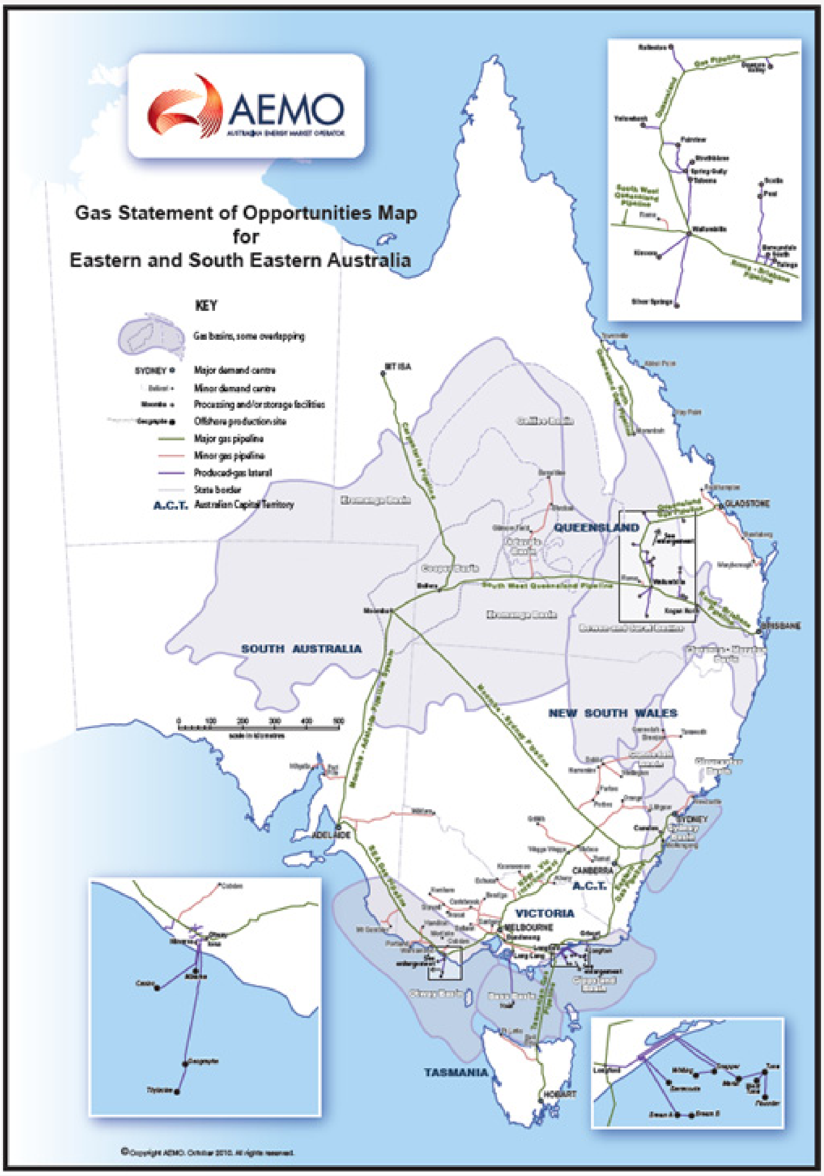
32 http://www.altonaenergy.com/index.php.

South Australia's gas is obtained via an interconnected pipeline network, with gas supplied from the Cooper Basin, Victoria, and Queensland.

Gas resources in Eastern and South Eastern Australia

Figure 4-5 illustrates major natural gas producing basins and gas transmission infrastructure in Eastern and South Eastern Australia, which is also described in AEMO's 2010 Gas Statement of Opportunities (GSOO).[33]

Figure 4-5 — Gas producing basins and infrastructure[34]



Eastern and South Eastern Australia gas reserves classified as 'proven plus probable' or '2P' totalled 43,798 PJ as at 31 December 2010. These reserves represent over 70 years of gas supply at the current rate of consumption.

33 http://www.aemo.com.au/planning/gsoo2010.html.
34 http://www.aemo.com.au/planning/gsoo2010.html.

Figure 4-6 shows the distribution of gas reserves occurring in the major gas basins. Coal seam gas makes up 84% of the reserves.

Figure 4-6 — Eastern Australia 2P gas reserves (as at 31 December 2010)[35]

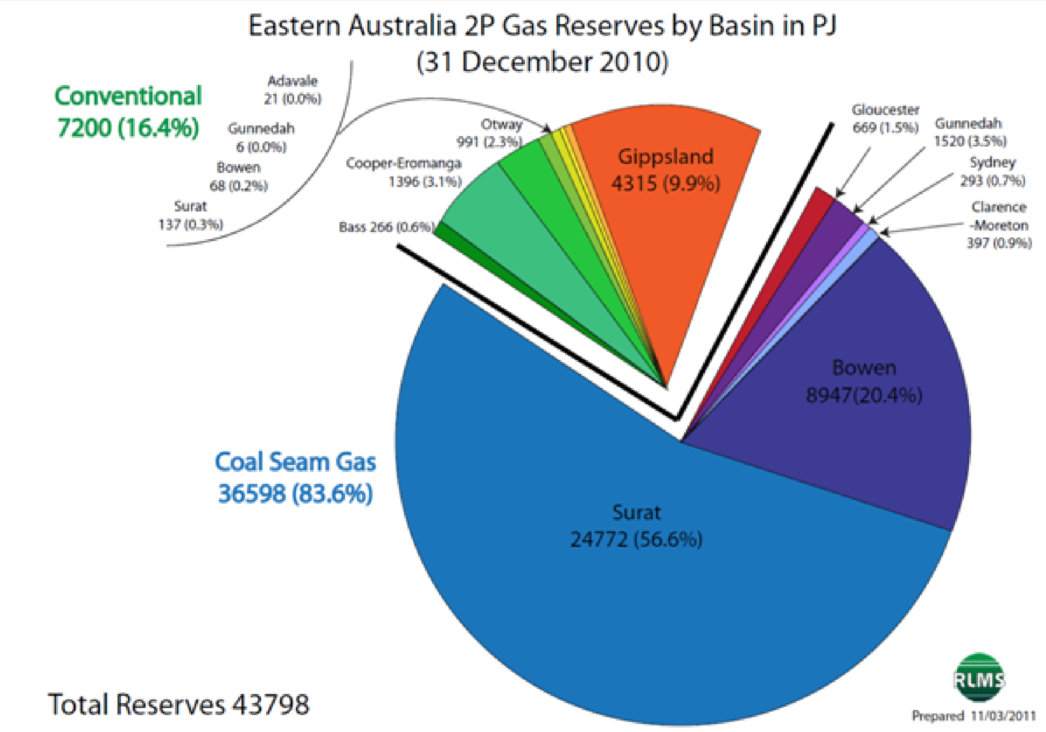
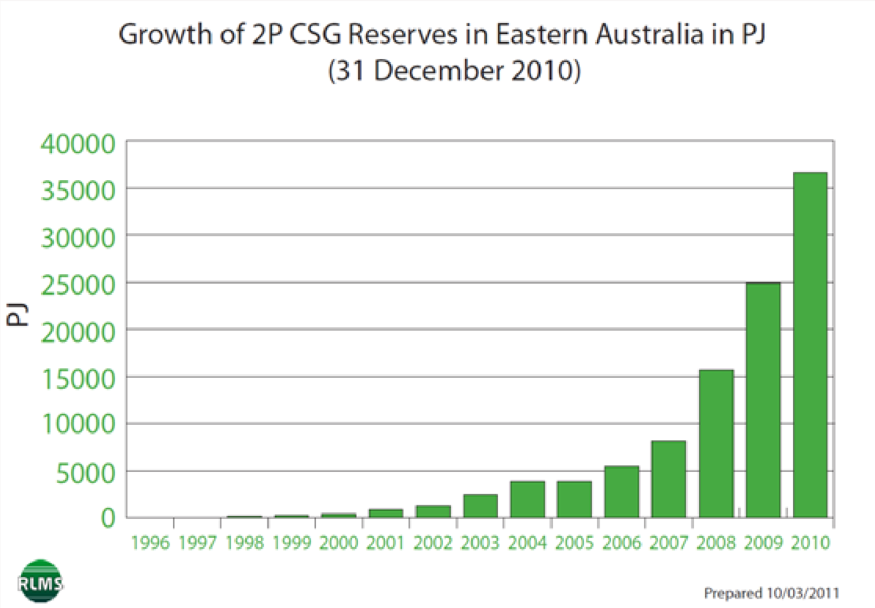


Figure 4-7 shows the growth in coal seam gas reserves from 1996 to 2010, demonstrating the recent increase in coal seam gas reserves in Queensland and New South Wales.

35 Resource Land and Management Services (RLMS), March 2011.

Figure 4-7 — Growth in coal seam gas reserves[36]



Much of Queensland's coal seam gas is likely to be exported as Liquefied Natural Gas (LNG) from facilities planned for Gladstone in Queensland. However, even allowing for LNG exports, the 2010 GSOO found that Eastern and South Eastern Australian gas reserves were sufficient to satisfy domestic and export demand projections until 2030. When less-certain resources are included, gas reserves and resources (as at 31 December 2009) totalled over 274,000 PJ, or nearly 400 years supply at the current consumption rate. The planned LNG facilities, however, will shorten that time.

In addition to coal seam gas, other unconventional gas sources (such as shale gas) are under investigation. A recent report by the US Energy Information Agency[37] reported more than 400,000 PJ of technically recoverable shale gas resources in four assessed Australian basins, including the South Australian Cooper basin, the Queensland Maryborough Basin, and the Western Australian Canning and Perth basins.

South Australian gas resources

Conventional gas

South Australia has traditionally sourced natural gas from the Cooper and Eromanga Basins. As shown in Figure 4-6, 2P reserves for the Cooper Basin are reported at 1,396 PJ or the equivalent of 13 years of South Australian gas consumption at the current rate. 2P reserves have increased by 185 PJ (15%) since 2009. Reserves from the Cooper and Eromanga basins represent only 3% of Eastern Australia's 2P gas reserves. Production from these basins reached a peak of 278 PJ/annum in 2001, but reached only 97 PJ/annum in 2010 (15% of east coast production) due to flooding and natural field decline.[38]

Unconventional gas sources in South Australia

Sources of unconventional gas (coal seam and shale gas) are being investigated, although there are large coal seam gas developments already planned for Queensland and New South Wales.

36 Resource Land and Management Services (RLMS), March 2011.
37 http://www.eia.doe.gov/todayinenergy/detail.cfm?id=811.
38 Energy Quest Energy Quarterly, February 2011, page 56.

Coal seams suitable for gas production are expected to exist in South Australia. According to the South Australia Department of Primary Industries and Resources, 15 coal seam gas exploration wells were drilled in 2009. Resources in excess of 20,000 PJ have been claimed, and drilling continues in 2011.

Shales generally have insufficient permeability to allow significant fluid flow to a well bore, making shale gas a historically difficult resource to access. Advances in hydraulic fracturing technology, however, have made economic extraction possible. The United States Energy Information Administration assessed technically recoverable shale gas reserves in the Cooper Basin at 90,000 PJ.[39]

Gas transmission infrastructure connecting South Australia to other regions

Gas is imported from Queensland and Victoria, making up for any shortfall within South Australia. Gas producers are also investigating additional conventional and unconventional gas resources within South Australia.

Table 4-2 lists the major gas pipelines relating to South Australia. As Figure 4-5 shows, gas can flow from Queensland to South Australia via the South West Queensland Pipeline and on to the Adelaide demand centre via the Moomba to Adelaide Pipeline (MAP). Gas can also be imported to South Australia from Victoria via the South East Australia Gas Pipeline (SEAGas). Gas is exported from South Australia to New South Wales via the Moomba to Sydney Pipeline (MSP).

Table 4-2 — Major gas pipelines relating to South Australia

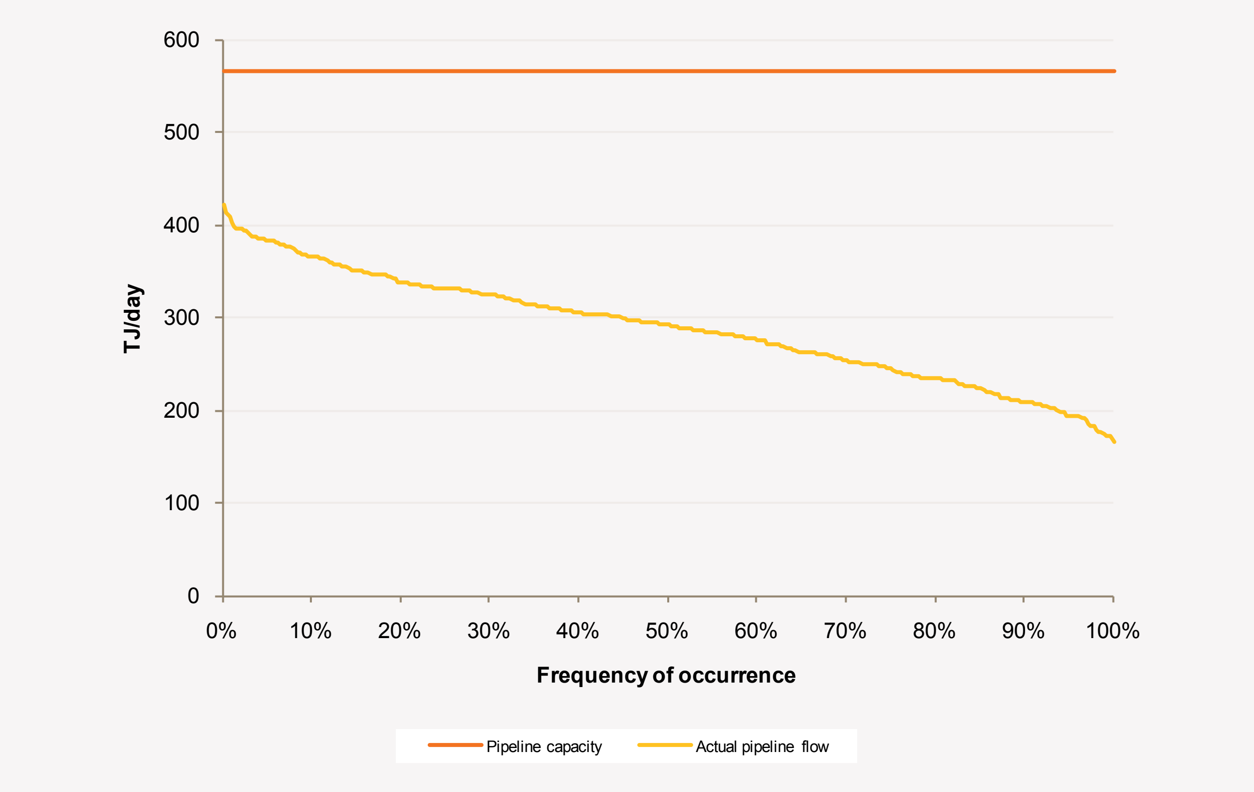
Gas pipeline	Length (km)	Diameter (nominal bore) (mm)	Year of initial construction	Capacity reported as at end of 2010 (TJ/Day)
South West Queensland Pipeline	935	400	1996	181
Moomba to Adelaide Pipeline	1,185	150, 200, 550	1969	253
Moomba to Sydney Pipeline	2,029	150, 200, 250, 300, 450, 850	1976	439
South East Australia Gas Pipeline	680	350, 450	2003	314

In 2010, South Australia exported 66 PJ of gas via the MSP, while importing approximately 71 PJ via the South West Queensland Pipeline and SEAGas Pipeline.

Regarding the major pipelines supplying the Adelaide demand centre, in 2010, the MAP operated at approximately 50% of full capacity, with flows ranging from 78 TJ/d to 198 TJ/d. In 2010, the SEAGas pipeline also operated at approximately 50% of full capacity, with flows ranging from 60 TJ/d to 245 TJ/d. Figure 4-8 shows the flow duration curve for the two pipelines combined, and the total pipeline capacities, which indicates there is generally spare capacity in the pipeline systems supplying gas to the Adelaide demand centre.

[39] U.S. EIA, "World Shale Gas Resources: An Initial Assessment of 14 Regions Outside the United States, April 2011.

Figure 4-8 — Combined SEAGas and MAP pipeline capacity and flow duration (2010)



For more information about these pipelines, see the 2010 GSOO.

Additional gas storage infrastructure

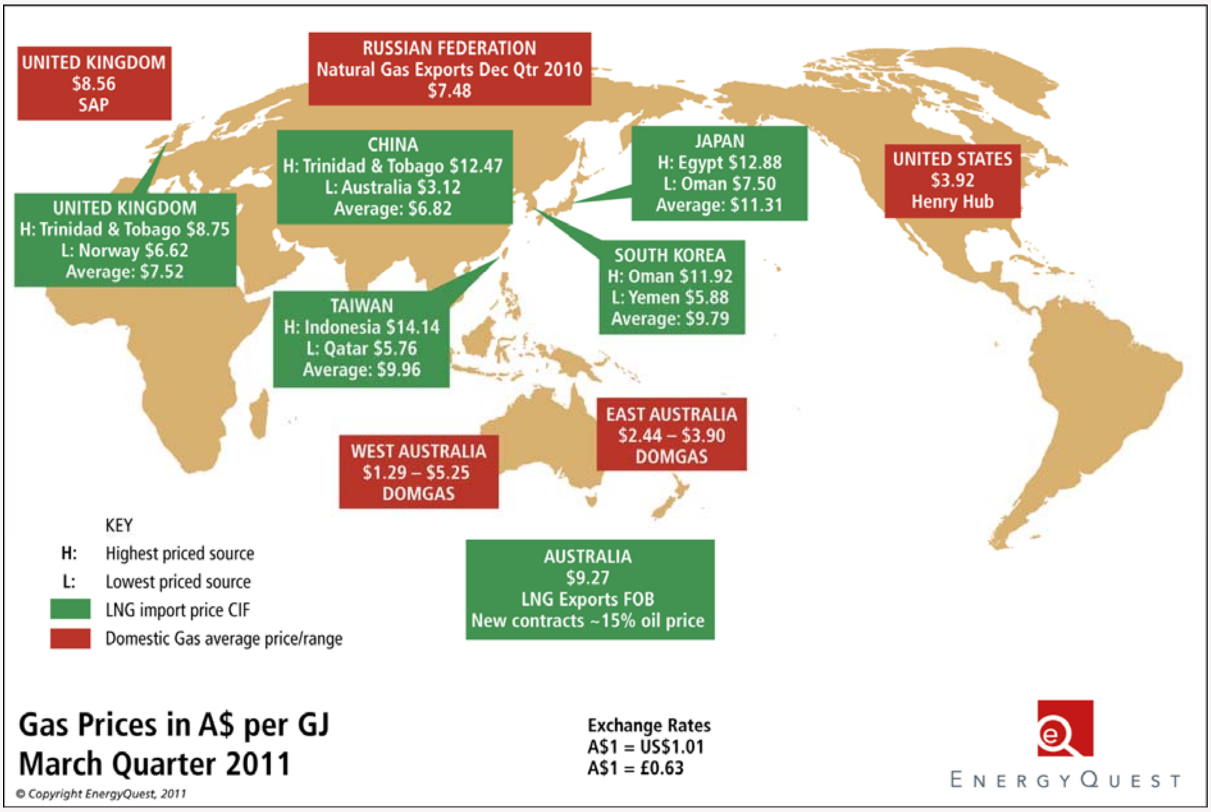
Gas storage facilities exist at the upstream ends of the MAP and SEAGas pipelines, at Moomba and at Iona. Other than line pack, there is no significant gas storage close to the Adelaide demand centre. Should meeting peak gas demand become an issue then options such as looping of the pipelines, additional compressors, and gas storage close to the point of consumption would provide additional capacity. AGL have already discussed plans to construct an LNG storage facility to support the development of an additional 700 MW of gas generation in Adelaide.[40]

Gas price commentary

Figure 4-9 shows international and Australian gas prices in $/GJ for the December quarter 2010. The international figures include the UK system average price (labelled 'SAP' in Figure 4-9), US Henry Hub spot gas price, the average export price for gas (predominantly pipeline gas) from Russia, and the average prices including cost, insurance, and freight (CIF) for LNG exported from Australia, and also for LNG imported into the European Union, Japan, Korea, Taiwan, and China.

[40] http://www.agl.com.au/about/EnergySources/indevelopment/Pages/TorrensIslandEnergyPark.aspx.

Figure 4-9 — International gas prices[41]



International prices have traditionally been higher than Australian domestic gas prices, leading to speculation that Eastern Australian gas prices may rise to export parity, as LNG facilities are built on the East Coast. Countering that view is the significant ongoing and potential development of coal seam gas reserves in Eastern Australia.

4.3.3 Liquid fuel availability in South Australia

Liquid fuels are used to generate electricity in both gas turbines and internal combustion engines. Some power stations in the state have a diesel/gas dual-fuel capability, and the coal-fired generators use fuel oil to start and for temporarily maintaining flame stability when changing output.

Approximately 40% of Australia's liquid fuels are imported. As these fuels are more expensive than generation from coal or natural gas, generation run solely on liquid fuel is limited to peak or emergency generation, or remote off-grid power generation (where the lower cost of providing fuel transport infrastructure is an issue).

Since the construction of the SEAGas pipeline, curtailments of gas supplies for electricity generation have been very rare and driven primarily by gas network emergencies. When gas supplies are restricted or contract quantities are reached, the open-cycle gas turbines (OCGT) at Hallett can use diesel, and the boilers supplying the steam turbines at Torrens Island A can use fuel oil. None of the current NEM combined-cycle gas turbine (CCGT) plants, including Pelican Point Power Station, have dual fuel capability.

Stockpiles of diesel are limited, and a project for the development of diesel fuel off take, storage and distribution facilities with potential subsequent stages for additional storage and refining facilities to be built at Port Bonython in

[41] Energy Quest Energy Quarterly, February 2011.

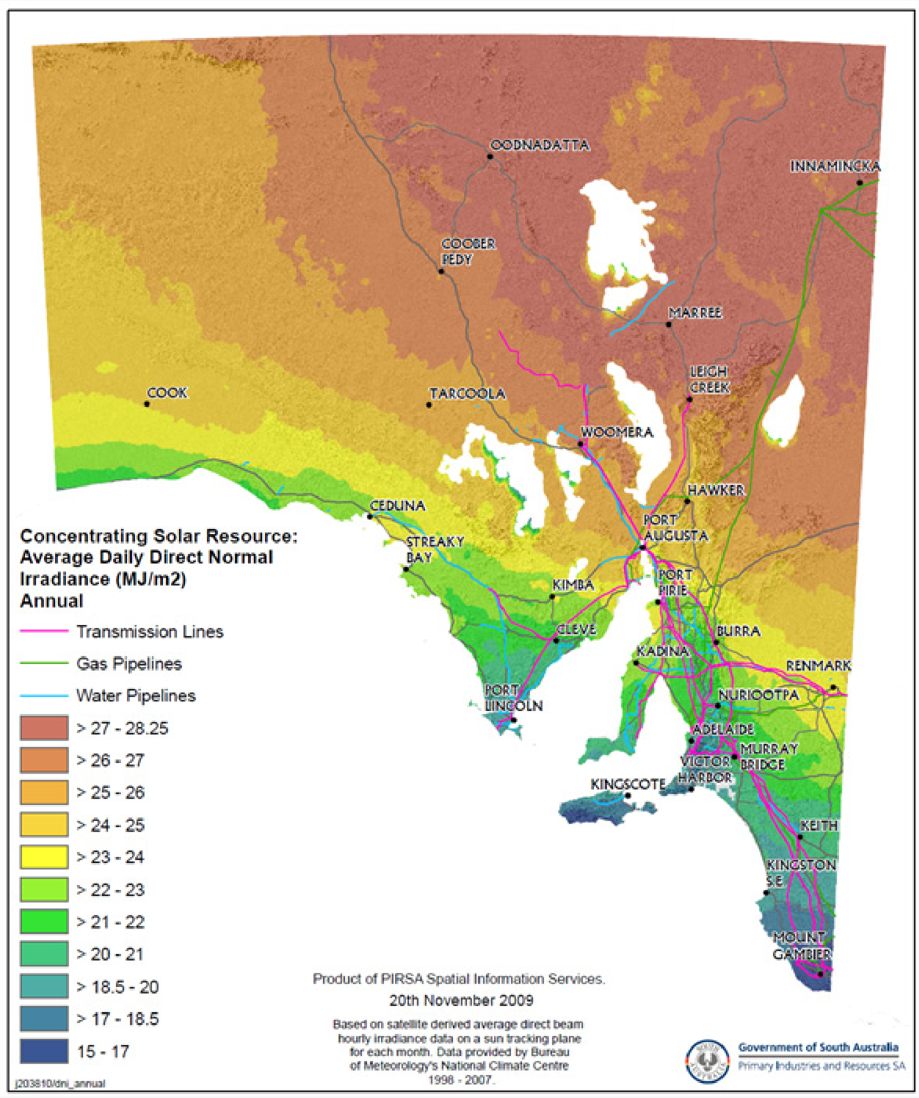
the upper Spencer Gulf in South Australia[42] has been awarded 'Crown Sponsored Development' status and has received development approval. The construction of this project would help alleviate this issue.

4.3.4 Renewable energy resource availability in South Australia

Solar

South Australia has significant solar resources, particularly in the more remote areas of the state. The output from solar generation, either from large utility-sized installations, or cumulatively, from domestic installations, varies with time. Figure 4-10 shows the average daily direct normal irradiance across the region. While this is a high quality resource, and has the potential to supply large quantities of energy, the capital costs of either solar photovoltaic or solar thermal technologies are still high and it may not be economic to exploit them at this stage without government support for sites other than some off-grid locations.

Figure 4-10 — Solar irradiance across South Australia[43]



[42] http://www.stuartpetroleum.com.au/content.aspx?p=103.

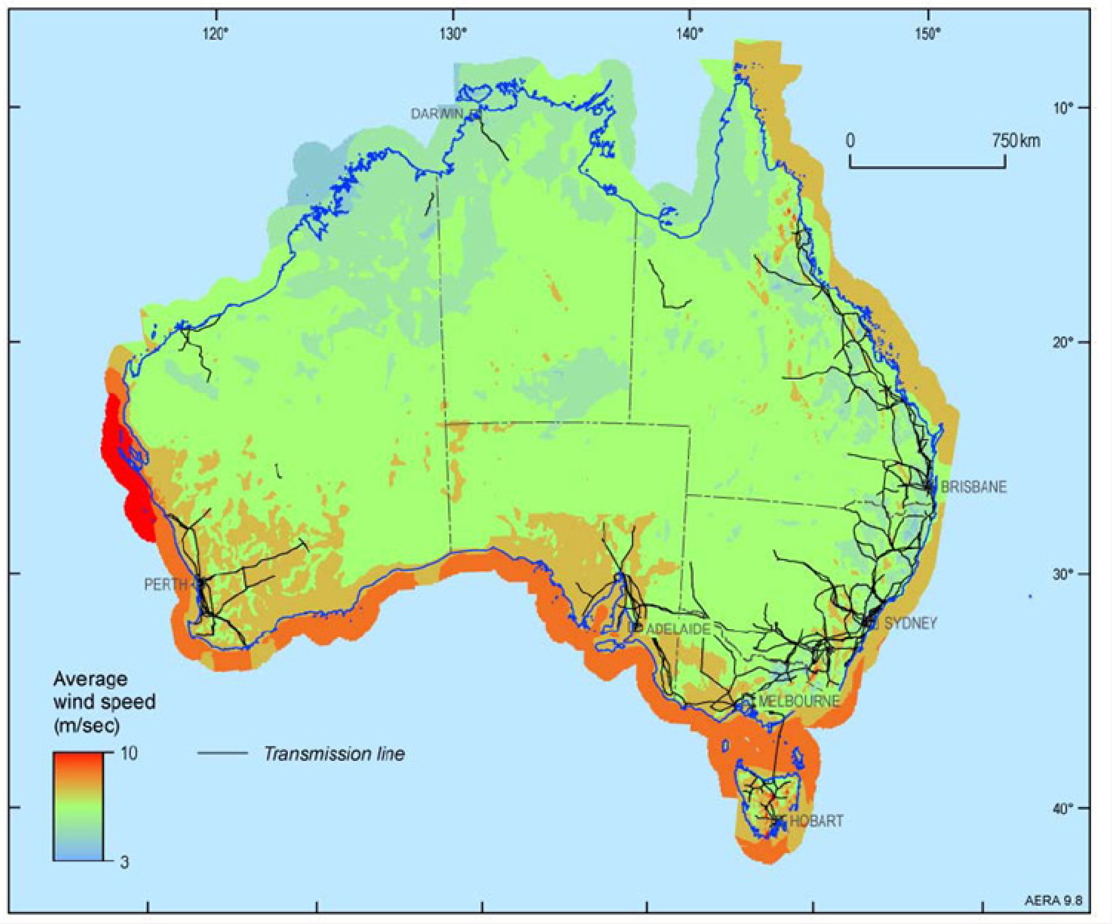
[43] http://www.renewablessa.sa.gov.au/investor-information/resources accessed 20 April 2011.

Wind

South Australia's wind resources largely derive from the Roaring Forties (strong westerly winds generally found between the latitudes of 40° and 49°), particularly along the coast, but also extending inland. Figure 4-11 provides an overview of wind resources in Australia. Wind generation is the most mature of the available renewable energy sources in South Australia, and significant quantities of wind generation already operate in the state. Wind farm developers have identified numerous potential sites for future projects.

The output of a wind farm varies over time as wind speeds change, and AEMO uses the Australian Wind Energy Forecasting System to predict individual wind farm output for market dispatch purposes and to manage this variability. All new large wind farms are required to be registered as semi-scheduled generators and, if necessary, usually at times of high wind and low demand, wind farms may be constrained to a lower output level to help manage the network and power system security.

Figure 4-11 — Predicted average wind speed at a height of 80 metres[44]



Geothermal

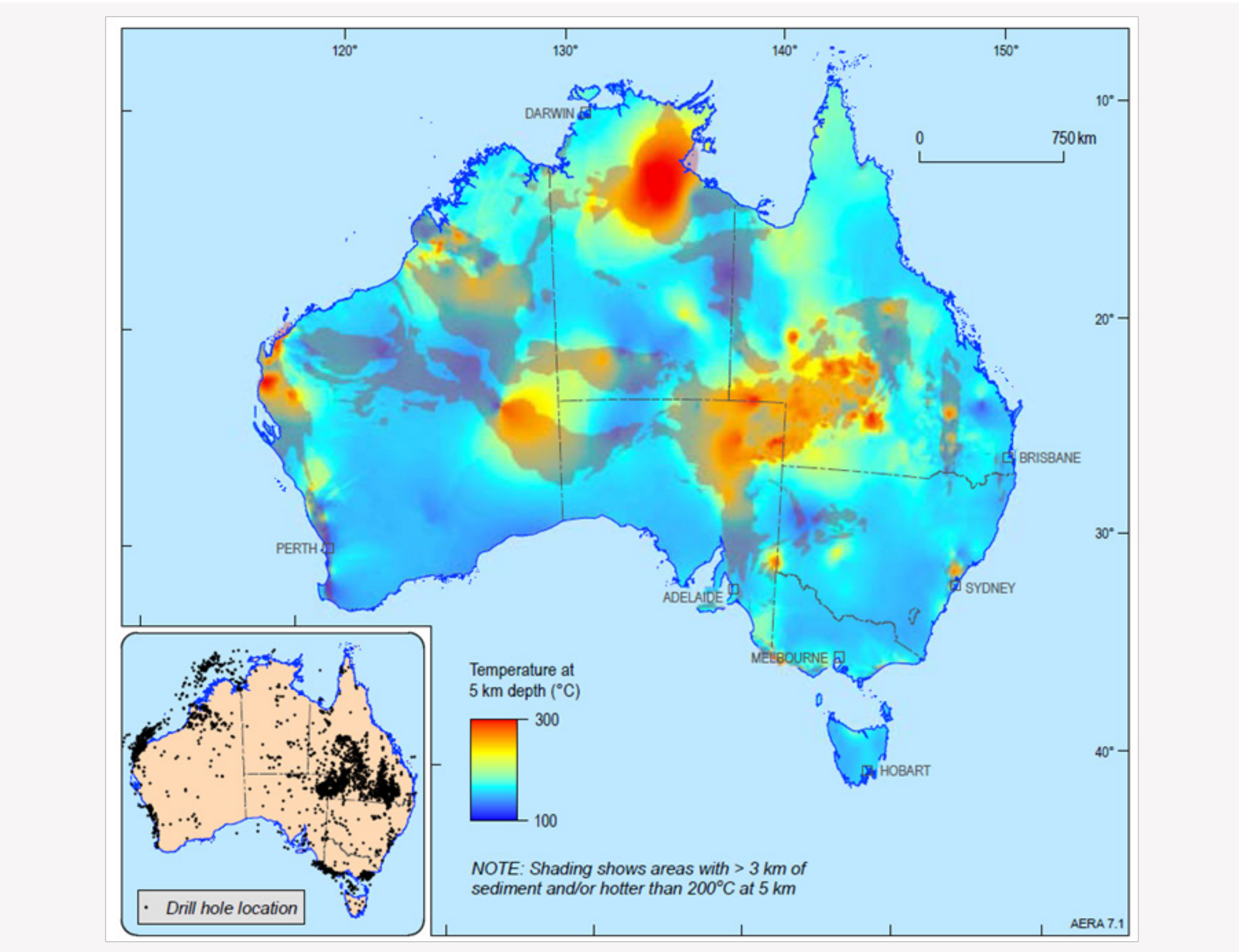
Australia has significant potential geothermal resources associated with high-temperature granites, and lower temperature geothermal resources associated with naturally-circulating waters in aquifers deep in sedimentary basins.

44 Geoscience Australia and ABARE, 2010, Australian Energy Resource Assessment, Canberra, based on data from Windlab Systems Pty Ltd.

Australian geothermal sources differ from traditional volcanic geothermal systems such as those found in New Zealand. In Australia, the proposed enhanced geothermal systems sites require drilling to depths of over 4,000 metres to obtain temperatures of approximately 250 ºC, while hot sedimentary aquifers provide lower temperatures (approximately 150 ºC) at a depth of approximately 3,000 metres. Appendix B - Technology discussion provides more information about these types of geothermal systems.

Figure 4-12 shows the geothermal resource distribution throughout Australia, and the significant South Australian area of high temperature rocks that appear to be suitable for geothermal energy extraction. A number of companies are developing projects to exploit this low marginal cost, zero emission fuel. Geothermal energy will provide a constant source of heat with the potential to provide high capacity factor electricity supplies. However, the geothermal technologies have yet to be proven at scale and it may not be economic to exploit this resource at this stage without government support.

Figure 4-12 — Predicted temperature at five kilometres depth[45]



For more information about renewable technologies, see Appendix A.

[45] Geoscience Australia and ABARE, 2010, Australian Energy Resource Assessment, Canberra based on data from EarthEnergy Australia Pty Ltd.

4.3.5 Fuel supply policy linkages

The Short-Term Trading Market for Gas

The Short-Term Trading Market for Gas (STTM) is a wholesale market system operated by AEMO[46], and is designed to facilitate short-term gas trading using daily, market-driven prices. The STTM has operated at hubs based around Adelaide and Sydney since September 2010, and is expected to commence operating at a Brisbane hub from 1 December 2011. AEMO is currently investigating the potential to expand the STTM to other hubs, including possibly hubs based around production centres. The Declared Wholesale Gas Market, covering much of Victoria, has been in operation since 1999.

The STTM operates in conjunction with underlying gas supply, transportation, and network contracts. The physical operation of pipeline or network assets is maintained by owners of the infrastructure. The existing retail gas market in South Australia operates in conjunction with the STTM.

The Australian Energy Regulator (AER) publishes weekly gas market reports on the STTM and Victorian Wholesale Gas Market. For more information about these reports, see the AER website.[47]

Carbon price

The Australian Government intends to introduce legislation later this year to establish a carbon pricing mechanism commencing on 1 July 2012. While final details of the legislation have not yet been released, public statements from the government have suggested its high level architecture, start date, potential mechanisms to allow flexibility to move to emissions trading, sectoral coverage, and international linking arrangements.

The proposed mechanism involves commencing with a fixed price before converting to a cap-and-trade emissions trading scheme at some future date. The government has not determined the details of the fixed price or the mechanisms or triggers to transition to a variable price trading scheme, and is still considering the details of assistance mechanisms, but has indicated that more than 50% of revenues will be used to compensate households, and there will be further compensation for trade-exposed industries and electricity generators.

Renewable energy target

As of 1 January 2011, the Australian Government Renewable Energy Target (RET) scheme was split into two parts: the Large-scale Renewable Energy Target (LRET), and the Small-scale Renewable Energy Scheme (SRES).

The SRES is designed to provide installation support for eligible small-scale devices such as solar water heaters, air-sourced heat pumps, and small generation units (small-scale solar panel, wind, and hydroelectric systems). The SRES provides an upfront deemed number of certificates that can be sold either directly to eligible parties at the current market price, or through a facilitated clearing house for a fixed price at sometime in the future.

The LRET is designed to provide an incentive for large-scale renewable power stations such as wind, solar, and hydroelectricity. Generators create certificates based on the energy they actually generate, which are sold on the open market.

For more information, see the Office of the Renewable Energy Regulator.[48]

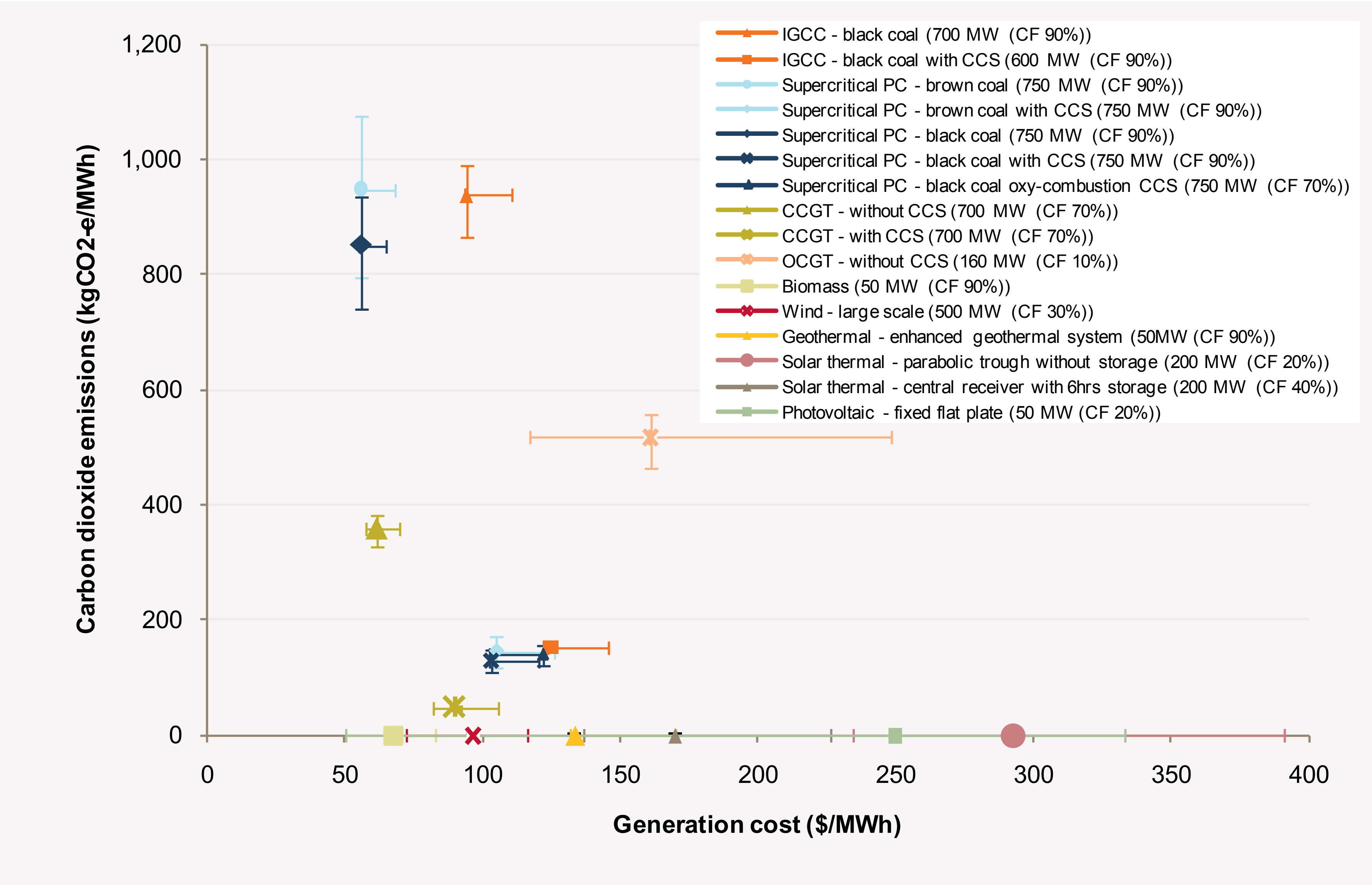
New entry technologies and emissions

Ahead of a potential carbon pricing mechanism, there is continuing interest in new generation technologies, their costs, and emissions. AEMO has analysed the relative costs of new generation from a range of different technologies, and the associated carbon emissions. To the extent possible, the data has been modelled on a consistent basis to provide comparative costs and emissions estimates.

Figure 4-13 shows the cost variations (as horizontal error bars) representing the range of potential long-run cost recovery requirements expected to occur across the normal annual operational range, and the variation of emissions (as vertical bars) expected from a reasonable range of generation efficiencies.

[46] http://www.aemogas.com.au/index.php?sectionID=9948&pageID=9954.
[47] http://www.aer.gov.au/content/index.phtml/itemId/729309.
[48] www.orer.gov.au.

Figure 4-13 — New entry generation technologies and emissions



[This page is left blank intentionally]

CHAPTER 5 - HISTORICAL GENERATION AND PERFORMANCE

5.1 Summary

This chapter provides information about historical levels of generation and performance of the supply sector in South Australia.

This year the approach to calculating figures for a “firm” contribution to wind generation has changed. Last year, a 95% confidence level was used to indicate an acceptable level of performance compared to conventional generation (meaning that the firm or reliable contribution was measured as the amount of generation that was likely to be available 95% of the time). Following research into alternate methods of calculating wind contributions to peak demand periods, this confidence level has been reassessed to 85%. Consequently the proportion of installed wind capacity considered to be firm in South Australia is calculated to be 5% in summer and 3.5% in winter.

The capacity of wind generation in South Australia continues to grow and wind energy has now reached 20% of energy production, There is now 1,150 MW of wind generating capacity in the state. According to the World Wind Energy Association’s data[49] this puts South Australia second behind Denmark in terms of penetration and the per capita figure of 0.702 kW per person is now higher than any major country in the world.

The Australian Energy Market Operator (AEMO) has analysed a number of parameters, such as variability and contribution to maximum and minimum demand, in the assessment of wind generation. The analysis found that the magnitude of fluctuations in wind generation increased when assessed over longer time intervals. The general trend shows variability falling as the number of wind farms increases, however, the reduction in variability is larger between 3 to 6 wind farms than between 6 to 9 wind farms. The reduction in variability between 6 to 9 wind farms and 9 to 14 wind farms is similar.

An analysis of energy demand and prices in South Australia indicated similar frequency demand levels over the past three years. However, South Australian wholesale electricity market prices for 2010/11 are lower than they have been since the start of the market and the relative gap between the volume weighted earnings price received by fossil fuelled generators (at 50.78 $/MWh) and the renewable generators (at 22.82 $/MWh) has widened.

5.2 Historical generation

Table 5-1 lists historical generation (energy) for South Australian power stations from 2005/06 to 2010/11. Figures for 2010/11 have been calculated on a pro-rata basis from data until 31 March 2011.

Table 5-1— Historical generation (energy) for South Australian power stations

	2005/06 (GWh)	2006/07 (GWh)	2007/08 (GWh)	2008/09 (GWh)	2009/10 (GWh)	2010/11 pro-rata (GWh)
Angaston	2	4	2	2	0	1
Dry Creek	1	16	10	6	9	3
Hallett	22	151	28	23	28	28

49 http://www.wwindea.org/home/index.php.

	2005/06 (GWh)	2006/07 (GWh)	2007/08 (GWh)	2008/09 (GWh)	2009/10 (GWh)	2010/11 pro-rata (GWh)
Ladbroke Grove	348	249	141	192	191	154
Mintaro	1	36	8	4	8	3
Northern	3,997	4,466	4,013	4,213	3,542	4,102
Osborne	1,176	1,251	1,230	1,244	1,189	998
Pelican Point	1,620	2,775	3,281	3,281	2,970	2,997
Playford	541	722	870	695	1,011	421
Port Lincoln	1	1	2	2	2	2
Quarantine	128	80	84	97	297	135
Snuggery	0	1	2	2	3	0
Torrens A	396	376	527	538	444	660
Torrens B	2,141	2,350	2,782	1,976	1,709	1,699
Clements Gap	0	0	0	3	165	173
Hallett 1	0	0	91	327	336	317
Hallett 2	0	0	0	16	250	242
Hallett 4	0	0	0	0	0	257
Lake Bonney S2	0	3	230	342	273	361
Lake Bonney S3	0	0	0	0	0	86
Snowtown	0	0	11	320	360	345
Waterloo	0	0	0	0	0	209
Non-scheduled wind	765	901	995	1,000	1,007	1,004
Total[a]	**11,140**	**13,382**	**14,305**	**14,282**	**13,792**	**14,198**

[a] Figures in this table are rounded to the nearest whole number and the table calculated prior to rounding.

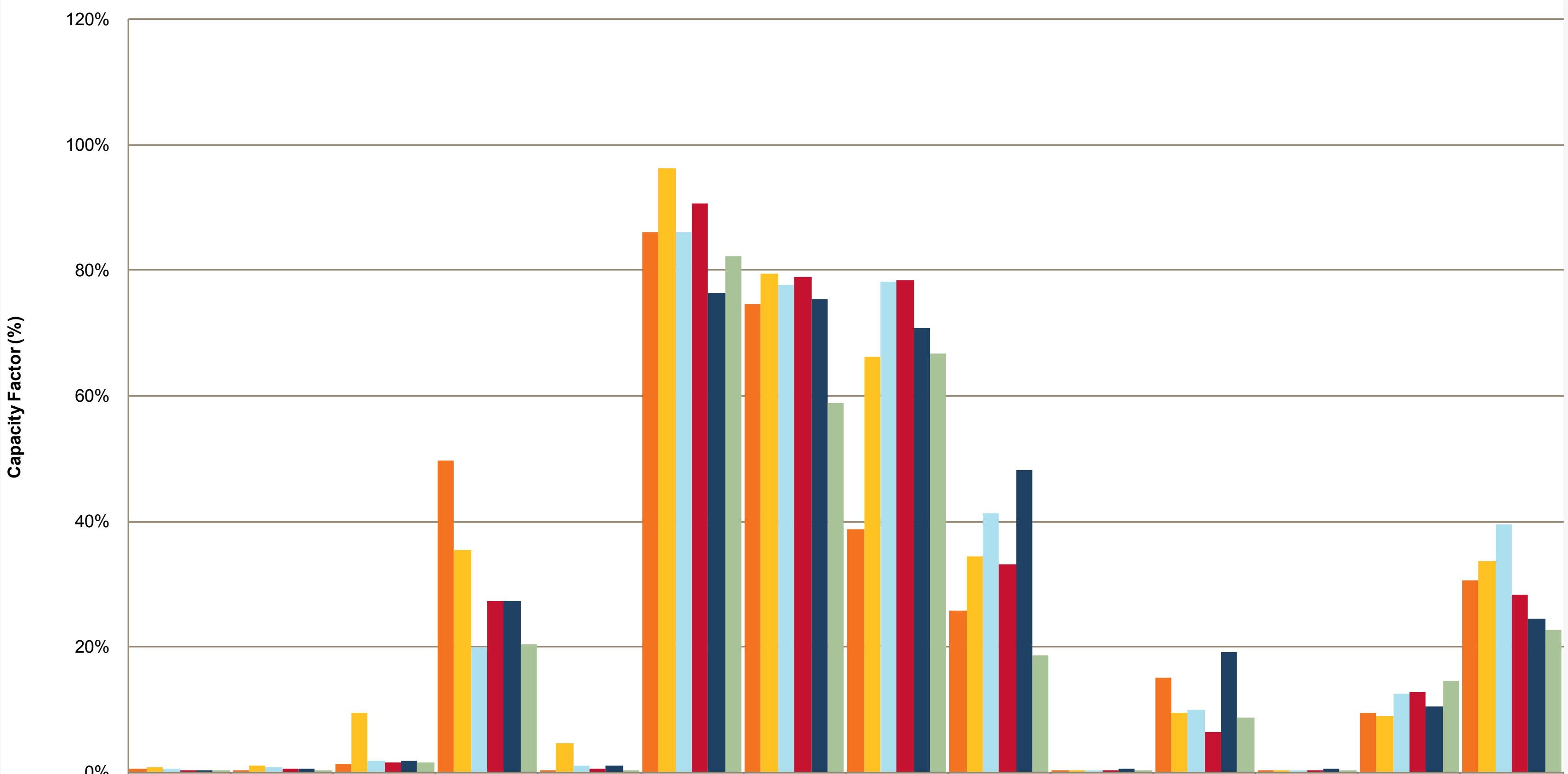
5.2.1 Capacity factors

Figure 5-1 and Figure 5-2 show the capacity factors for South Australia generation based on each power station's historical registered capacity. Plants that respond to peak demand generally have very low capacity factors, as they only operate for short periods and are idle for most of the year. Plants providing base load power have higher capacity factors, and tend to produce power continuously, unless shut down for maintenance.

Wind farm capacity factors primarily depend on wind speed and availability, although temperature and transmission network limitations can also affect the output. Some farms switch off or reduce their output during high temperatures to prevent temperature-related equipment damage.

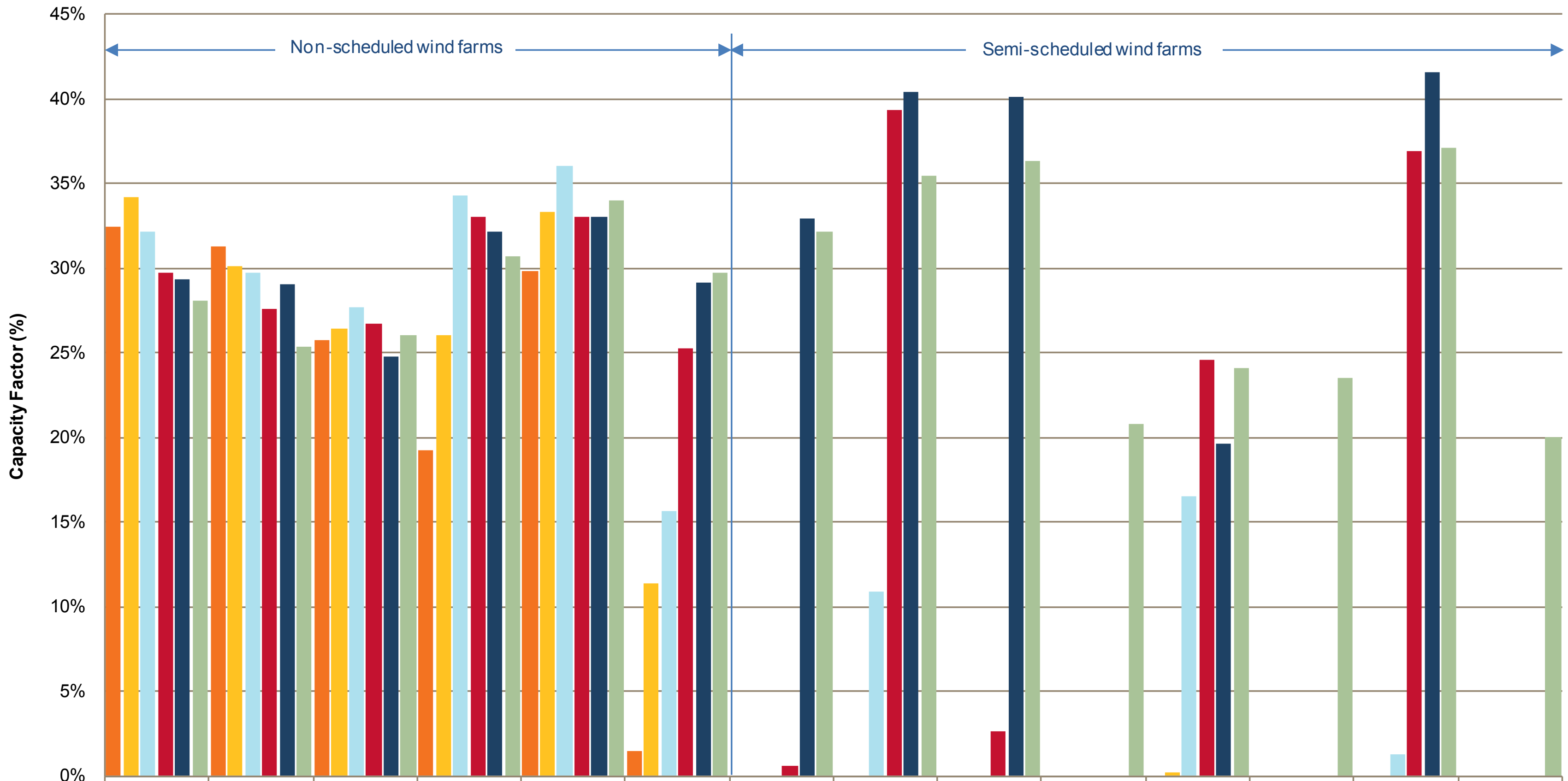
Hallett 1, Hallett 2, and Snowtown Wind Farms have the highest capacity factors, ranging from 35.5% to 41.5% over the past two years. Of the wind farms that have had at least a full year of operation, Lake Bonney 2 has the lowest capacity factor (24.1%). Lake Bonney 3, Waterloo, and Hallett 4 (North Brown Hill) have only been fully commissioned within the past year, and may have lower capacity factors due to being incomplete or not generating for part of the year.

Figure 5-1 — Financial year capacity factors for scheduled generators



	Angaston	Dry Creek	Hallett	Ladbroke Grove	Mintaro	Northern	Osborne	Pelican Point	Playford	Port Lincoln	Quarantine	Snuggery	Torrens A	Torrens B
2005/06	0.6%	0.1%	1.4%	49.7%	0.2%	86.1%	74.6%	38.7%	25.7%	0.1%	15.2%	0.1%	9.4%	30.6%
2006/07	0.8%	1.1%	9.6%	35.5%	4.5%	96.2%	79.4%	66.3%	34.4%	0.1%	9.5%	0.2%	8.9%	33.5%
2007/08	0.5%	0.7%	1.8%	20.0%	1.0%	86.2%	77.8%	78.1%	41.2%	0.4%	10.0%	0.4%	12.5%	39.6%
2008/09	0.4%	0.4%	1.5%	27.3%	0.5%	90.8%	78.9%	78.4%	33.1%	0.4%	6.4%	0.3%	12.8%	28.2%
2008/10	0.1%	0.7%	1.8%	27.2%	1.0%	76.3%	75.4%	70.9%	48.1%	0.5%	19.1%	0.5%	10.6%	24.4%
2010/11	0.2%	0.2%	1.7%	20.5%	0.4%	82.3%	59.0%	66.7%	18.6%	0.3%	8.8%	0.1%	14.6%	22.6%

Figure 5-2 — Financial year capacity factors for non-scheduled and semi-scheduled generators (wind farms)



	Canunda	Starfish Hill	Lake Bonney	Cathedral Rocks	Wattle Point	Mt Millar	Clements Gap	Hallett 1 (Brown Hill)	Hallett 2 (Hallett Hill)	Hallett 4 (Nth Brown Hill)	Lake Bonney 2	Lake Bonney 3	Snowtown	Waterloo
2005-06	32.4%	31.3%	25.8%	19.3%	29.8%	1.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2006-07	34.2%	30.1%	26.4%	26.0%	33.3%	11.4%	0.0%	0.0%	0.0%	0.0%	0.2%	0.0%	0.0%	0.0%
2007-08	32.2%	29.7%	27.6%	34.3%	36.1%	15.6%	0.0%	10.9%	0.0%	0.0%	16.5%	0.0%	1.2%	0.0%
2008-09	29.7%	27.6%	26.7%	33.0%	33.0%	25.3%	0.6%	39.3%	2.6%	0.0%	24.5%	0.0%	36.9%	0.0%
2009-10	29.3%	29.0%	24.7%	32.2%	33.0%	29.2%	33.0%	40.4%	40.1%	0.0%	19.6%	0.0%	41.5%	0.0%
2010-11	28.1%	25.3%	26.0%	30.7%	34.0%	29.7%	32.2%	35.5%	36.3%	20.7%	24.1%	23.5%	37.1%	20.0%

5.3 Inter-regional supply

South Australia is connected to the rest of the NEM via the Victoria-South Australia (Heywood and Murraylink) interconnectors.

5.3.1 Heywood

The Victoria-South Australia (Heywood) interconnector has a nominal dispatch limit of 460 MW, but the actual limit can vary in response to local network thermal ratings, voltage and reactive power limits, system demand and generation in the south east of South Australia.

5.3.2 Murraylink

The Murraylink interconnector connects Victoria and South Australia via the Riverland. While it is nominally rated at 220 MW the actual limit depends on the direction of flow and local conditions. For power flows from South Australia to Victoria, thermal limits on the 132 kV transmission system in the Riverland region area restrict power flows on Murraylink to less than 180 MW (with runback schemes in place). At times of low demand, power flows from Victoria to South Australia can be limited by transient stability limitations in Victoria or South Morang 500/330 kV transformer thermal limits, and at times of high demand, flows can be limited to less than 50 MW by voltage collapse constraint equations applied to Victoria.

5.3.3 Combined Heywood and Murraylink interconnector limits

As well as individual capabilities, there is a maximum combined transfer capability for the Murraylink and Heywood interconnectors. On 6 January 2011, the combined nominal maximum transfer capability for South Australia to Victoria was increased from 420 MW to 580 MW. This combined limit is affected by a number of physical and electrical limits, which are described by a series of specific constraint equations that include operational factors, such as demand, the output from certain power stations, and the status of specific items of transmission plant in both regions.

These constraint equations have been developed by the transmission entities in South Australia and Victoria for use by AEMO in determining dispatch patterns. There are many limitations that can reduce the maximum power transfer capability of the interconnectors under certain circumstances. Constraint equations also change over time to address specific transmission network alterations, including network augmentations, the connection of new loads, and the commissioning of new generation.

Power transfers between regions are managed by AEMO, within the limits defined by these constraint equations, in the National Electricity Market Dispatch Engine (NEMDE).

5.3.4 Historical interconnector flows

Table 5-2 and Table 5-3 show the total energy imported and exported, and the average power flow rates for both the Murraylink and Heywood interconnectors for each financial year.

Table 5-2 — Historical Heywood interconnector power flow

Financial year	Total imports (GWh)	Total exports (GWh)	Import average (MW)	Export average (MW)
1999/2000	3,574	1	408	63
2000/01	2,471	18	291	69
2001/02	1,439	123	198	83
2002/03	2,191	54	272	77
2003/04	2,554	31	305	74
2004/05	2,214	59	272	95
2005/06	2,374	35	285	83
2006/07	1,246	235	193	102
2007/08	657	526	140	129
2008/09	829	436	156	119
2009/10	1,109	304	182	114
2010/11 pro-rata	829	313	192	138

Table 5-3 — Historical Murraylink interconnector power flow

Financial year	Total imports (GWh)	Total exports (GWh)	Import average (MW)	Export average (MW)
2002/03	206	10	86	35
2003/04	217	60	46	28
2004/05	305	38	46	22
2005/06	270	31	41	20
2006/07	87	156	30	33
2007/08	40	176	20	29
2008/09	52	218	24	35
2009/10	80	267	31	43
2010/11 pro-rata	63	241	42	43

Figure 5-3 shows total imports and exports into South Australia from 1999/2000 to 2010/11. Energy imported into South Australia from Victoria during the year is plotted in orange column bars above the (zero) 0 GWh line (x-axis), and energy exported from South Australia to Victoria is shown below the line.

Historically, South Australia has imported electricity from Victoria, with net imports decreasing from 2006/07 to 2010/11. At the same time, the number of periods where South Australia exported energy to Victoria has increased. This corresponds with recent increases in wind generation in South Australia, and may have been influenced by drought conditions affecting supply in the eastern states.

Figure 5-3 — Total interconnector exports and imports

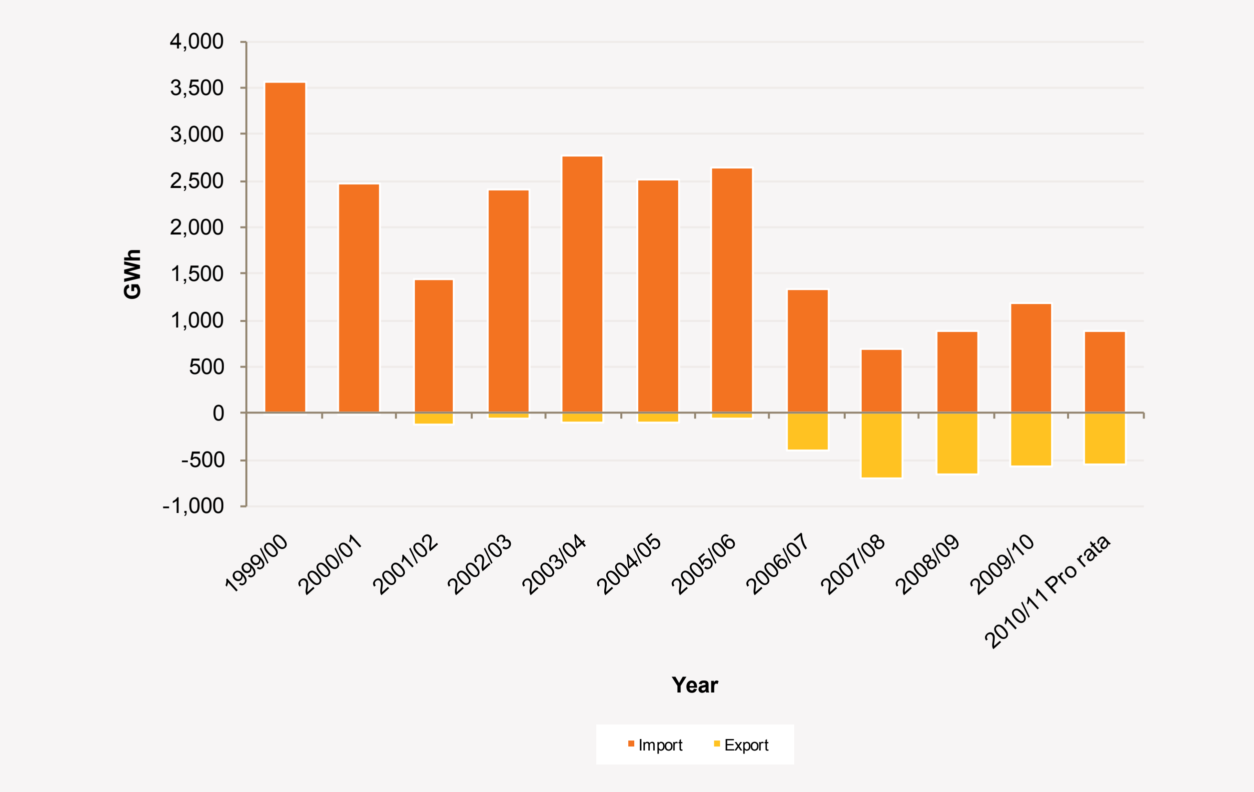
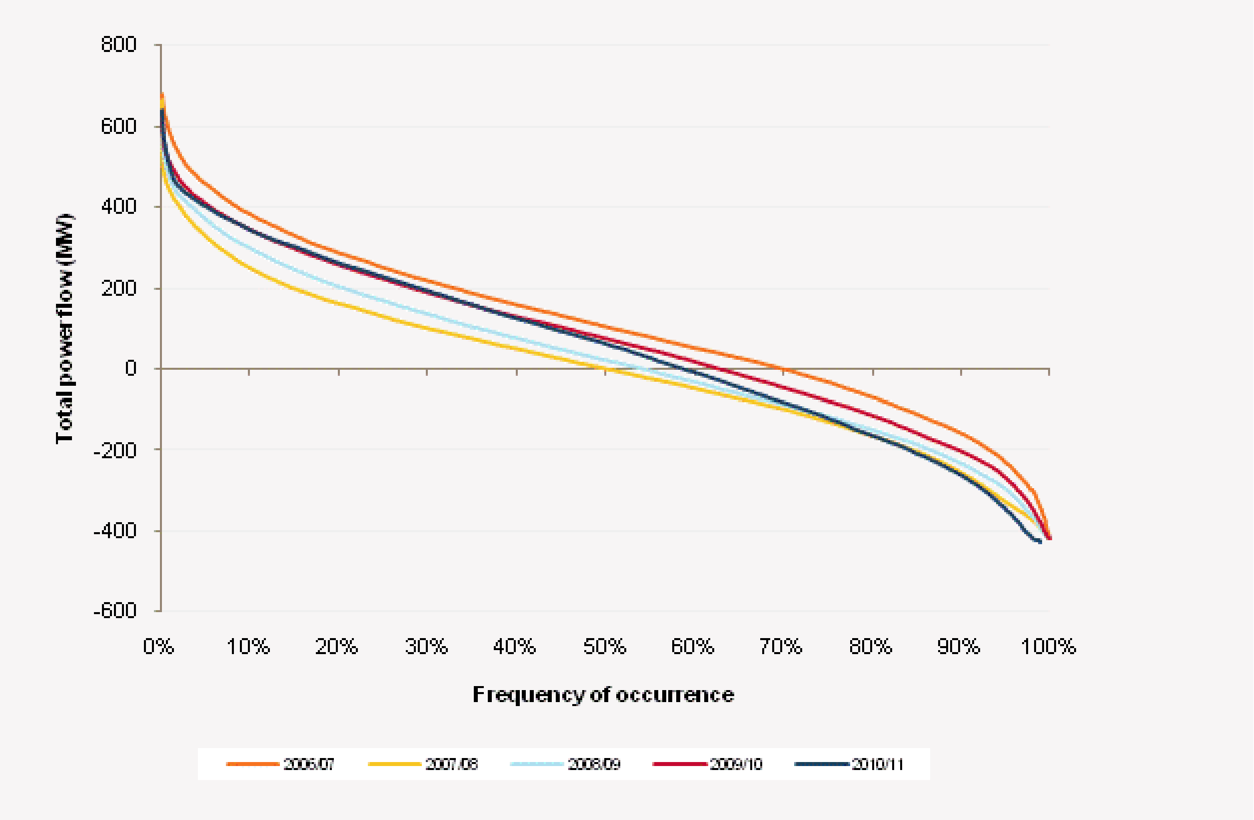


Figure 5-4 shows the combined flow duration curves for the Heywood and Murraylink interconnectors for the years from 2006/07 to 2010/11. Flow duration curves are a graphical representation of the frequency that the interconnectors were transferring specific amounts of power. The area between each curve and the x-axis represents the amount of energy transferred between South Australia and Victoria. If the area above the x-axis to the curve is greater than the area below the x-axis to the curve, it means that South Australia has imported energy from Victoria (net imports).

Figure 5-4 — Combined Heywood and Murraylink interconnector flow duration curve



Prior to 2006, South Australia was a large importer of power from Victoria when the interconnector contributed almost a fifth of state's energy needs. The flow duration curve for 2006/07 sits to the right of the other curves, demonstrating the tail end of this trend with high levels of imports (the area between the x-axis and the curve on the right-hand side of the figure for this year is significantly smaller than the area between the x-axis and the curve on the left-hand side of the figure, indicating net imports). This was followed by a drop to the left in 2007/08, when South Australia became a small net exporter of power to Victoria (5 GWh).

From 2007/08 to 2009/10, the interconnectors were used at progressively higher rates. The 2010/11 curve sits mostly to the left of the previous year, representing fewer periods of high imports and more frequent exports.

5.4 Wind analysis

Generally, across the day, the output from wind farms in South Australia is quite well correlated as all wind farms in the state experience relatively consistent atmospheric conditions. However, their output fluctuates over shorter time frames in response to local conditions. Infrequently these short time-frame fluctuations can be synchronised causing potential system security issues.

5.4.1 Wind Performance

South Australia has the highest penetration of wind generation in Australia, with wind farms contributing a considerable amount of energy, and able to deliver significant combined instantaneous output. Table 5-4 lists the combined maximum half-hourly output for all the wind farms operating in the state.

Table 5-4 — Maximum half-hourly wind farm output from 2004/05 to 2010/11

Financial year	Installed capacity (MW)	Maximum half-hourly output (MW)
2004/05	318	235
2005/06	334	286
2006/07	493	320
2007/08	685	540
2008/09	740	641
2009/10	868	765
2010/11[a]	1,150	978

[a] The end-date of the 2011 data used was 31 March 2011.

The significant growth of wind generation over recent years, and the variability of wind over a short period of time, means that transmission network and power system management is becoming more challenging.

Figure 5-5 shows changes in wind generation (variability) as a percentage of total wind farm installed capacity over different time intervals. The chart shows the number and magnitude of fluctuations over the period 2003 to 2011.[50] This is based on a frequency analysis of the number and magnitude of the fluctuations in wind generation over different time intervals. For example, the half-hourly variability represents the difference between each 30-minute reading. Similarly, the six hourly variability is the difference between wind farm output readings six hours apart. The analysis uses raw generation data and does not take into account any changes in generation caused by bidding behaviour of scheduled or semi-scheduled wind farms or variations caused by the imposition of constraints applied either by AEMO or the network service provider on the output of the generator.

The results show that variability is greater over a longer period of time. The six-hourly variability shows that for approximately 1.2% of the time the fluctuation is 50% of total installed capacity or more, while the half-hourly variability shows that for the same percentage of time the fluctuation is 15% of total installed capacity or less. On a half-hourly basis there were only 16 occurrences where the fluctuation was greater than 50%.

50

Figure 5-5 — Variability as a proportion of installed capacity

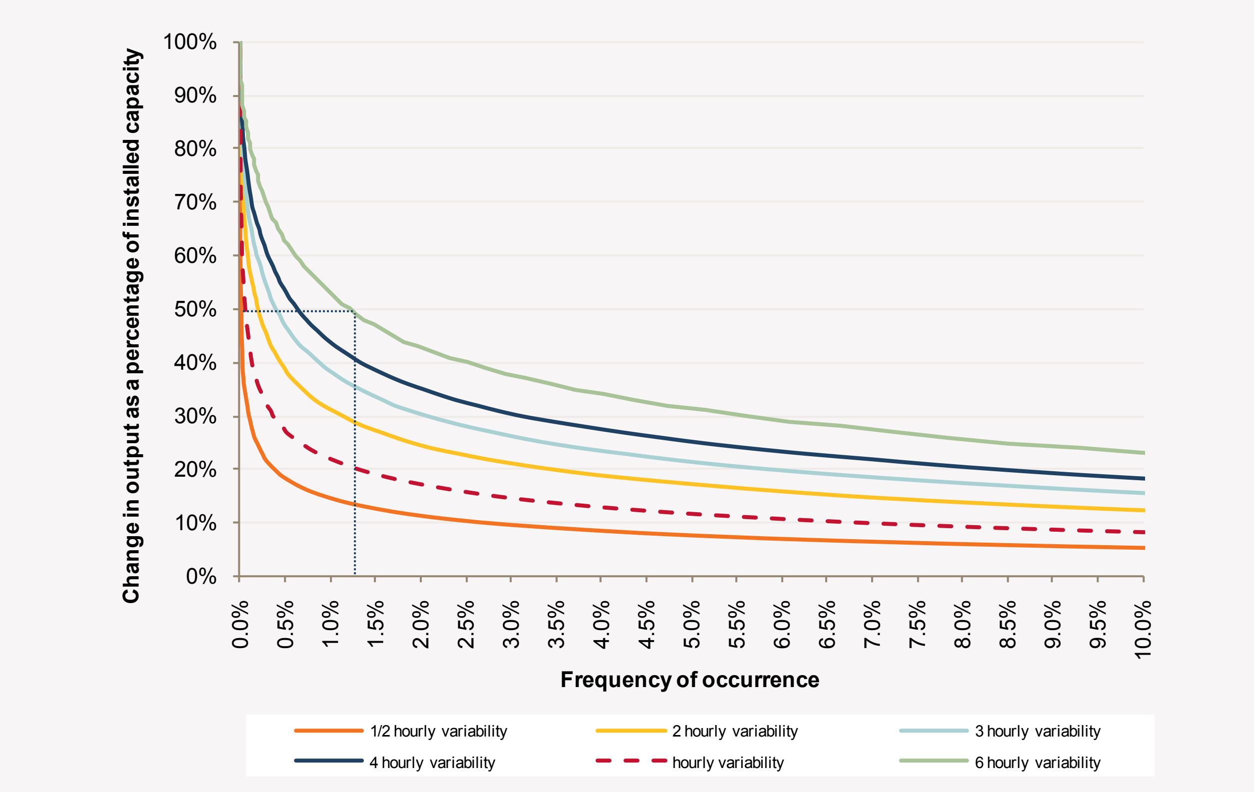


Figure 5-6 shows the variability with increasing numbers of wind farms over different time intervals. Charting intervals ranging from half-hourly to four-hourly, it presents a similar analysis to wind variability as a proportion of installed capacity (Figure 5-5). Examining four different increments of development, the data is divided into subsets based on the number of operating wind farms (three, six, nine, and fourteen), and is designed to highlight the change in variability as more wind farms are connected.

The first and longest data set includes the half-hourly generation readings from the state's first three wind farms, covering the period from when the third wind farm commenced operation to 31 March 2011. The second data set covers the first six wind farms from the time when the sixth wind farm in the state commenced operation to 31 March 2011. The third covers nine wind farms. The fourth data set covers the last eight months when 14 wind farms were operating. The data set for the 14 wind farms may be less reliable as a result.

The general trend shows variability falling as the number of wind farms increases. The most notable and largest reduction occurs between three and six wind farms, reflecting the benefit of diversity. The reduction in variability between six and nine wind farms is significantly less pronounced, and is barely evident with 14 wind farms. The reasons for this are still being investigated.

Variability is higher over the longer time intervals (two and four-hourly), and the reduction in variability on a percentage of installed capacity basis masks the increase in the actual variation that is occurring.

Figure 5-6 — Wind variability charts

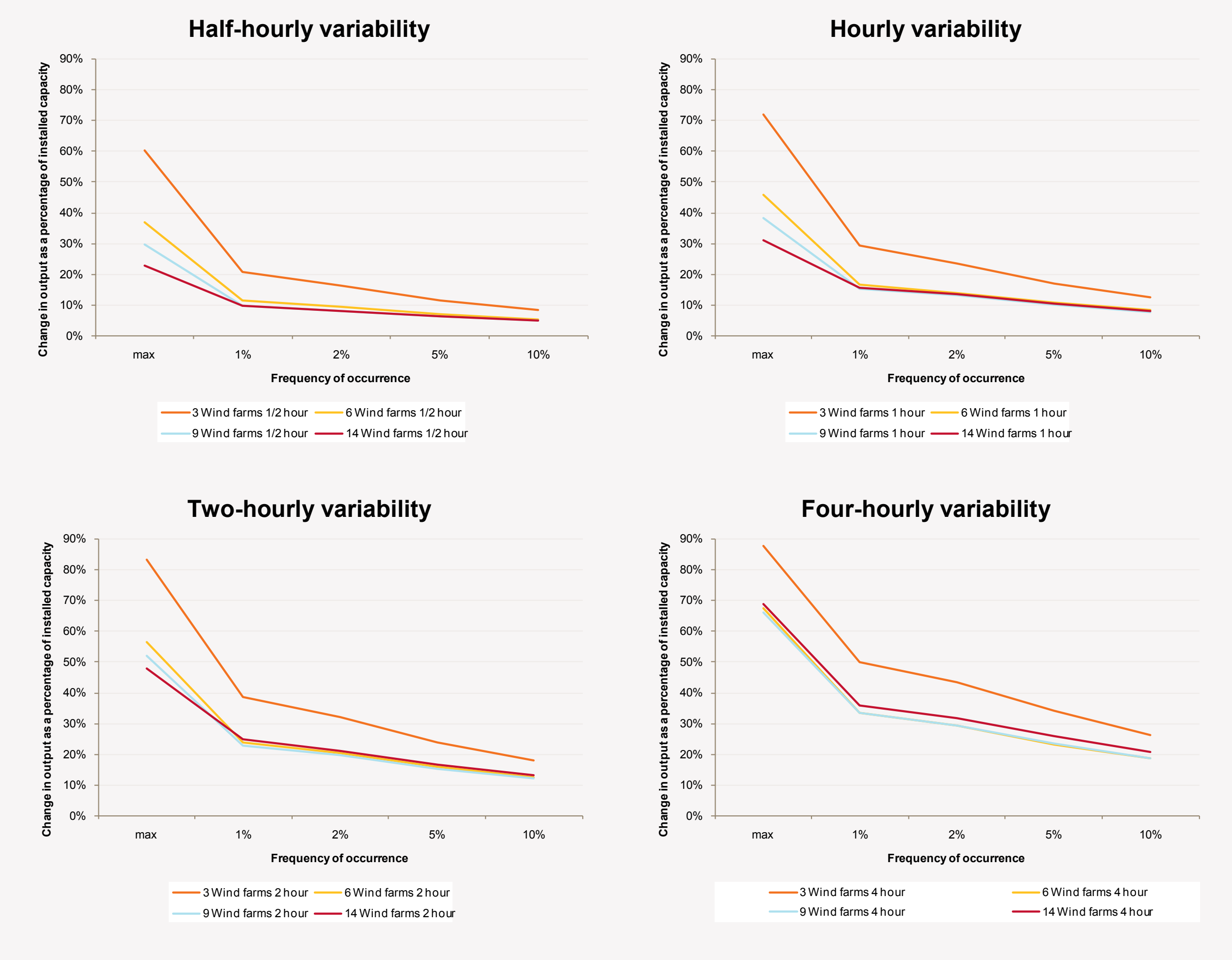


Table 5-5 compares total wind farm installed capacities with variability. For example, with an installed capacity of 1,150 MW across fourteen wind farms, the largest half-hourly change was 253 MW, which is similar in size to the region's largest fossil-fuelled generating unit. The largest four-hourly change, however, was 757 MW, which is approximately the same size as the region's normal daily load variation. The loss of 253 MW over 30 minutes is not as challenging for the market operation as it would be if it was instantaneous. However, managing changes of this magnitude increases the importance of accurate forecasting, particularly with respect to the timing of significant changes.

These results highlight that while variability is relatively small as a percentage of total installed capacity, as installed capacity increases, the magnitude of that variability becomes more challenging to manage.

Table 5-5 — Total installed capacity and maximum half-hourly and four-hourly variability

Wind farms	Installed capacity (MW)	Maximum half-hourly variability (MW)	Maximum 4-hourly variability (MW)
3 wind farms	161	97	141
6 wind farms	388	143	258
9 wind farms	740	220	490
14 wind farms	1,100	253	757

Table 5-6 shows key statistical information about variability over five and ten-minute intervals, contrasting the change in variability as more wind farms have been developed.

The variation as a percentage of installed capacity for the 10% and 5% frequency of occurrence calculations is relatively consistent for six and nine wind farms, but higher for 14. The 1% frequency of occurrence and maximum data set values are showing that over time-frames less than four hours there is a diversity benefit.

Australian and international research into wind variability confirms that the correlation between the behaviour of wind farms reduces significantly with distance and with shorter time periods to the point where some are increasing their output while others are decreasing. That is, as the time frames considered decrease, the correlation between the output of wind farms decreases.

Research is ongoing, with the University of South Australia, School of Mathematics and Statistics, to better understand this outcome. Short-term wind variability and the variation in customer demand are both supplied via the ancillary services market.

Table 5-6 — Five and ten-minute variability[a]

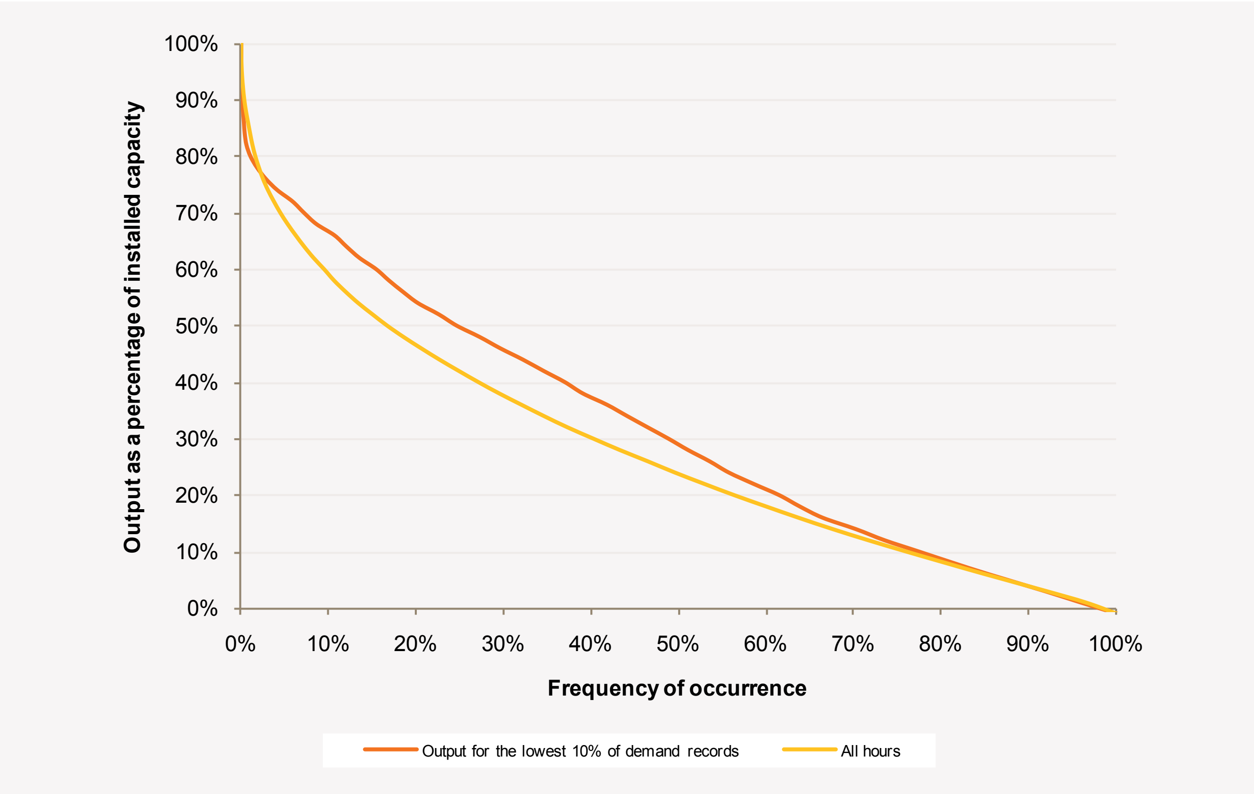
	6 Wind farms		9 Wind farms		14 Wind farms	
	Five-minute	Ten-minute	Five-minute	Ten-minute	Five-minute	Ten-minute
Mean	0.72%	1.09%	0.77%	1.18%	0.85%	1.32%
Median	0.43%	0.65%	0.51%	0.79%	0.60%	0.93%
Standard deviation	0.92%	1.38%	0.88%	1.32%	0.90%	1.36%
Variation as a percentage of installed capacity						
10% frequency of occurrence	1.7%	2.6%	1.7%	2.7%	1.9%	2.9%
5% frequency of occurrence	2.4%	3.6%	2.3%	3.6%	2.5%	3.8%
1% frequency of occurrence	4.4%	6.6%	4.0%	6.2%	4.2%	6.5%
Maximum	28.8%	29.8%	22.6%	26.2%	20.4%	22.1%

a. The analysis datasets were created on the same basis as the longer time intervals. While the size of the fourteen wind farm dataset is limited to the last eight months, the means and medians increase with the number of wind farms, implying more variability as numbers increase.

5.4.2 Wind contribution during low demand periods

Of particular interest for South Australia, where the load factor is quite low, is the output of wind farms during low demand periods where the minimum output of the fossil fuelled generators, interconnector capacity and potential wind generation can result in both network and generation constraints.

Figure 5-7 — Generation duration curve for wind generation during periods of low demand



AEMO has considered the contribution of wind generation at periods of low South Australian demand. Figure 5-7 is a graphical representation of those times when demand was within 10% of the minimum South Australian demand. These periods of low demand tend to be overnight, and the results indicate that wind at these times is more variable than average. However for over 50% of these times, wind generation is above the average. This analysis is based on the actual production from the wind farms and does not account for wind operators reducing their output in response to negative market prices or being constrained off to maintain network security. The results suggest that there may be opportunities for network development to exploit these periods of high wind generation and low demand. This is being further investigated in the 2011 National Transmission Network Development Plan (NTNDP).

5.4.3 Wind contribution during peak demand

Within a planning framework, such as that used to assess where there is sufficient generation to meet demand, it is necessary to calculate a peak demand contribution figure. Wind generation contribution was previously calculated using wind farm outputs during summer peak periods for a given confidence level. The confidence level was set as a percentage that represented the typical reliability of a fossil-fuelled generator. In the past, this level was set at 95%, meaning that the full output of the generator would be available during peak periods at least 95% of the time.

Recently this approach has been more intensively scrutinised and alternate methods have been examined. For the purposes of this analysis, AEMO has used a confidence interval to 85% because a 95% availability is potentially overly conservative. Establishing the contribution from wind on this basis involves mathematically sampling the normalised historical wind generation dataset, and statistically analysing the frequency that different levels of output occur for two subsets.

Another potential approach for the future could be to use a simulation technique where, within the 0.002% Reliability Standard, the contribution at peak demand is determined by calculating the equivalent capacity of a non-stochastic generator, such as an open-cycle gas turbine. This methodology would be highly computationally intensive, likely to be quite specific with respect to the configuration of the wind farms and difficult to generate a statistically significant sample.

Subset 1 involves the wind contribution for periods when demand is within 10% of each financial year's maximum demand.

Subset 2 involves the wind contribution during the top 10% of demand records.

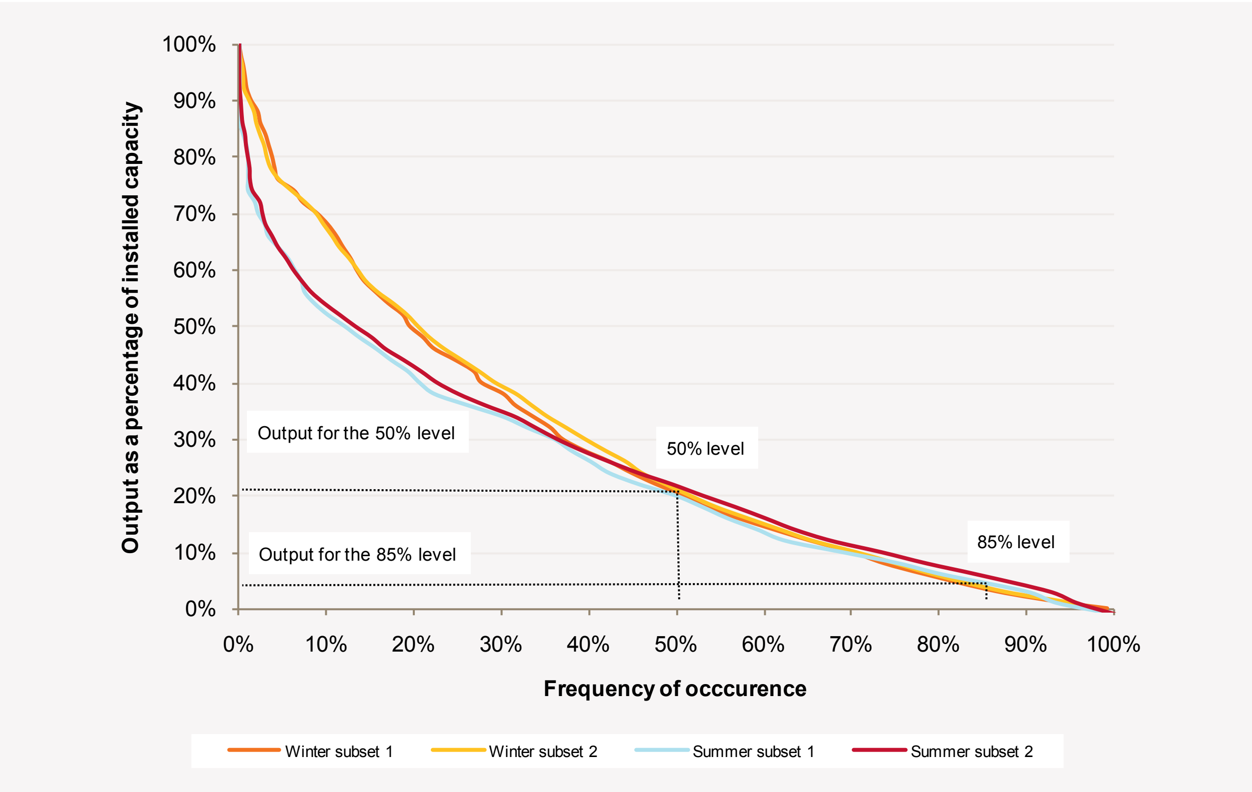
Figure 5-8 shows the contribution of wind generation from the two subsets during summer and winter as a proportion of peak demand. Two points have been marked on the figure (50% and 85%) showing the range of likely outputs during periods of high demand.

Based on the recorded performance of wind generation during the top 10% of summer demand records, wind generation in South Australia contributes at least 5% of its installed capacity for 85% of the time, and at least 20% of its installed capacity for 50% of the time. The results for the 85% level for summer and winter are listed in Table 5-7.

Table 5-7 — Wind contributions

	Summer	Winter
Contribution	5%	3.5%

Figure 5-8 — Peak demand period wind generation duration curves



5.4.4 Period of high temperature January/February 2011

South Australia experienced a short period of high temperatures in late January and early February 2011. Table 5-8 lists the recorded temperatures for the period.

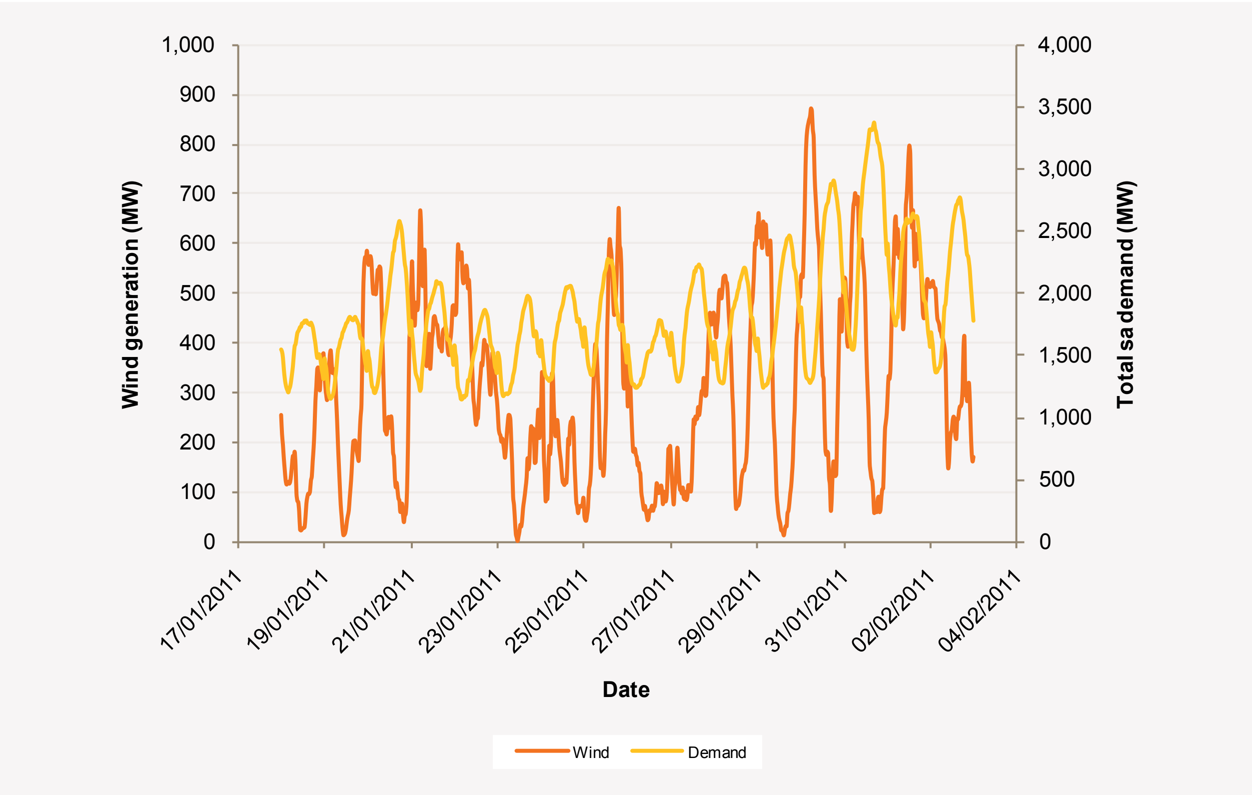
Table 5-8 —January/February 2011 heat wave

Date	20th	21st	22nd	23rd	24th	25th	26th	27th	28th	29th	30th	31st	1st	2nd
Day	Th	Fr	Sa	Su	Mo	Tu	We	Th	Fr	Sa	Su	Mo	Tu	We
Max temp (°C)	37.0	29.2	32.1	32.0	27.3	32.5	29.6	32.0	31.8	37.7	42.5	42.9	33.2	36.0

Figure 5-9 shows wind generation and total South Australian demand for the same period. The maximum contribution from wind during this period was 873 MW at 5:30 AM on 30 January 2011, and peak demand (the demand supplied by scheduled, semi-scheduled, and significant non-scheduled generating units) was 3,433 MW at 4:30 PM on 31 January 2011.

The figure, which demonstrates the correlation between demand and wind generation, shows that as demand increased, the contribution from wind generation fell. While the output of some wind turbines is limited during periods of high temperature, the output of the wind farms increases due to local winds created by heating and cooling of the land mass at sunrise and sunset.

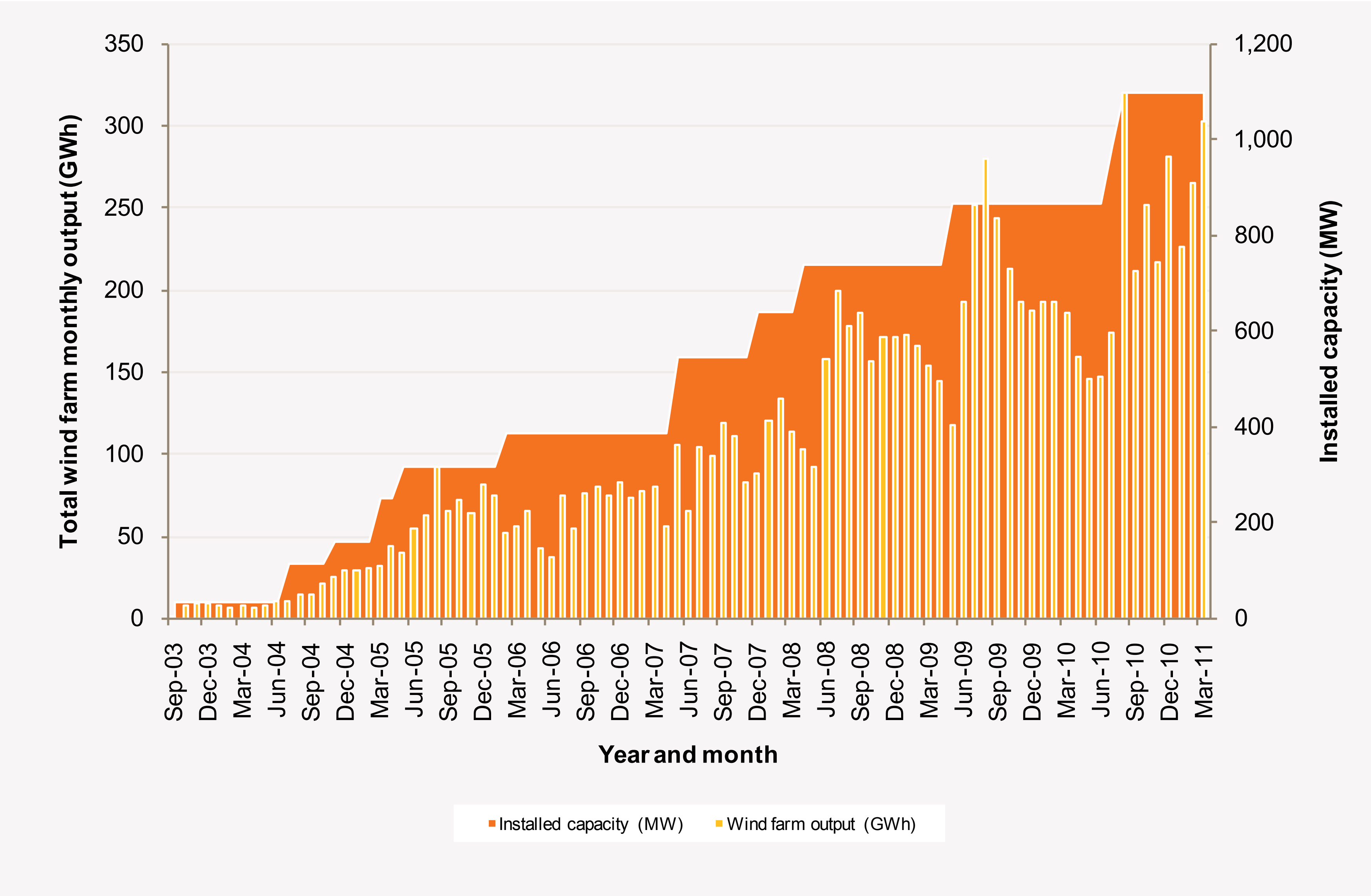
Figure 5-9 — Wind generation and total South Australian demand from 20 January 2011 to 2 February 2011



5.4.5 Seasonal variations in wind generation

Figure 5-10 shows the monthly energy production figures from wind farms operating in South Australia since September 2003. The highest output generally occurs during the winter months, and prominent heatwaves cause a significant decline in monthly output.

Figure 5-10 — South Australian total wind generation September 2003 to March 2011



ATTACHMENT A1 - ENERGY POLICIES AND FORECAST ASSUMPTIONS

A1.1 Energy policies and market trends

A1.1.1 Emissions trading/carbon price assumptions

It is important to highlight that any emissions policies and reduction targets set in Australia will be dependent on the nature of agreements reached at the international level.

In Australia, efforts to introduce an emissions trading scheme have suffered setbacks over the last two years, with the original Carbon Pollution Reduction Scheme Bill failing to pass the senate on three separate occasions in 2009 and 2010. This led the Australian Government to announce in April 2010 that the introduction of a carbon policy would be delayed until at least 2013. However, in February 2011, the Australian Government announced its intention to implement a carbon price by 1 July 2012 and a cap and trade[51] system within three to five years. Considerable progress still needs to be made to obtain agreement on the details of the policy. The government has yet to announce a final emissions target, although it has committed to an unequivocal reduction of 5% below 2000 levels by 2020.

The assumptions used in the 2011 South Australian Supply and Demand Outlook (SASDO) present a significant impact on energy and maximum demand electricity consumption in South Australia when the carbon policy is introduced, due to the forecast increase to the average electricity retail price. It should be noted that while the economic forecasts were developed before the government's February announcement, the starting carbon price and the length of the fixed period are still to be determined. Therefore, the regional energy and maximum demand projections assume that a carbon price will come into effect from 2013/14.

To manage the uncertainty surrounding the future economic outlook and, more specifically, developments within the stationary energy sector, the Australian Energy Market Operator (AEMO) has developed a set of scenarios that incorporate a range of different assumptions about key drivers of economic growth.

In addition to external drivers of growth, the scenarios incorporate assumptions of domestic productivity growth. The inclusion of productivity assumptions manages the uncertainty associated with future technological innovations, business investment, labour force skill development, and government policy aimed at enhancing productivity.

Table A1-1 lists the assumptions relating to the carbon price that have been incorporated into the three economic scenarios used for the energy forecasts. The baseline scenario assumes that an international agreement on emissions reductions is reached, but most countries advocate a slow and steady approach to mitigation. Carbon price paths are universally adopted by the international community, but the overall price level is only moderate. In Australia, the carbon price (in 2009/10 prices) is set at 37.44 \$/t CO2-e in 2014/15.

The high growth scenario assumes a strong international agreement on emissions reduction targets, with relatively high carbon prices imposed within Australia and the rest of the world. Accordingly, the carbon price in Australia is set at 49.97 \$/t CO2-e in 2014/15. Conversely, the low growth scenario assumes that there is little support for emissions reduction policies, both within Australia and internationally. As a result, only a low carbon price is introduced in Australia (26.91 \$/t CO2-e in 2014/15) with a minimal response from the rest of the world.

51 A 'cap and trade' emissions trading scheme allows the issuer of permits (the Australian Government) to restrict the volume of emissions, while the price of the obligatory emissions permits are determined by the market. The cost of purchasing permits (or reducing emissions) is legally borne by particular entities, including electricity generators, but passed on to energy consumers. As a result, an emissions trading scheme will affect both NEM energy and demand indirectly, through the general economic impact; and directly, through electricity prices.

Table A1-1 — Carbon price assumptions

Low scenario	Medium scenario	High scenario
• Low emissions reduction targets agreed internationally.	• Moderate emissions reduction targets in Australia and internationally.	• International agreement of strong emissions reduction targets.
• Carbon price based on Treasury estimates for a cut in emissions of 5% on 2000 levels by 2020.	• Carbon price based on Treasury estimates for a cut in emissions of 15% on 2000 levels by 2020.	• Carbon price based on Treasury estimates for a cut in emissions of 25% on 2000 levels by 2020.
Carbon prices		
• Carbon price grows by real rate of 4% p.a. from 2014/15 onwards.	• Carbon price grows by real rate of 4% p.a. from 2014/15 onwards.	• Carbon price grows by real rate of 4% p.a. from 2014/15 onwards.
• Peaks at 48.46 \$/t CO2-e in 2030.	• Peaks at 67.36 \$/t CO2-e in 2030.	• Peaks at 90.00 \$/t CO2-e in 2030.

Carbon prices considered by AEMO were established by the Australian Government Treasury[52] and the Department of Climate Change and Energy Efficiency, analysing the economic impacts of mitigation policies, particularly a carbon price, to reduce greenhouse gas emissions.

The high, medium and low carbon price trajectories are listed in Table A1-2. In each case it is assumed that a transitionary scheme is put in place, whereby a carbon price is initially introduced at 10 \$/t CO2-e in 2013/14, before the full scheme is implemented in 2014/15. Further, the carbon price under each scenario is assumed to grow by a real rate of 4% per annum from 2014/15 onwards, reflecting the fact that carbon permits are financial assets and are bankable over time. This assumption is based on a 2% annual return and 2% risk premium.

Table A1-2 — Carbon price trajectories (2009/10 AUD)

	Low	Medium	High
2013/14	10.00	10.00	10.00
2014/15	26.91	37.44	49.97
2015/16	27.98	38.93	51.97
2016/17	29.10	40.49	54.05
2017/18	30.27	42.11	56.21
2018/19	31.48	43.79	58.46
2019/20	32.74	45.55	60.80
2020/21	34.05	47.37	63.23
2021/22	35.41	49.26	65.76
2022/23	36.82	51.23	68.39
2023/24	38.30	53.28	71.13
2024/25	39.83	55.41	73.98
2025/26	41.42	57.63	76.93
2026/27	43.08	59.94	80.01

52 The Australian Government Treasury and the Department of Climate Change and Energy Efficiency modelled the potential economic impacts of reducing emissions over the medium and long term and released the Report Australia's Low Pollution Future: The Economics of Climate Change Mitigation on the 30 October 2008.

	Low	Medium	High
2027/28	44.80	62.33	83.21
2028/29	46.59	64.83	86.54
2029/30	48.46	67.42	90.00
2029/31	50.40	70.12	93.60

Considering the Australian Government announcement that a carbon price could be implemented by 1 July 2012, some alternative potential carbon prices for the years to 2014/15 are shown in Table A1-3.

Table A1-3 — Carbon price trajectories under a potential carbon price implementation for 1 July 2012 (2009/10 AUD)

	Low	Medium	High
2012/13	20.00	20.00	20.00
2013/14	20.00	20.00	20.00
2014/15	26.91	37.44	49.97

The change would impact South Australian electricity prices for the financial years 2012/13 and 2013/14, while for 2014/15 onwards carbon prices are forecast to remain at the same level as under the initial trajectories. Since the long-term carbon price is substantially the same as that used in the initial analysis, it will not affect the macro-economic parameters and as such the proposed new arrangements would have a very small impact on electricity prices. Therefore, these alternative carbon prices have not been incorporated in the electricity forecasts.

A1.1.2 Other energy policy assumptions

Renewable Energy Target

The national Renewable Energy Target (RET) scheme was implemented by the Australian Government in August 2009[53] to ensure that 20% of Australia's electricity supply will come from renewable sources by 2020.

In June 2010, the RET was divided into two parts, the Large-scale Renewable Energy Target (LRET) and the Small-scale Renewable Energy Scheme (SRES), from January 2011. This modification is expected to deliver more renewable energy than the mandatory production target of 45,000 GWh in 2020 (estimated to be 20% of electricity supply).[54]

Later, in December 2010, the Australian Government announced amendments to the solar credits multiplier, which will apply from July 2011, in recognition of significant reductions in the cost of solar panels.

Current estimates suggest there is approximately 72 MW worth of roof-top solar photovoltaic panels installed in South Australia.

In other words, solar photovoltaic (PV) penetration has been experiencing a remarkable growth that is likely to continue increasing over the coming years, not only for residential but also for commercial utility-scale applications, depending on Government policies.

Government initiatives and independent market trends could have an impact on energy markets. For this reason, AEMO engaged KPMG to evaluate the potential effect of developments, such as the Australian Government's RET

53 The national RET scheme expands on the previous Mandatory Renewable Energy Target (MRET), which began in 2001.

54 Further details on the new national RET scheme arrangements are described in Attachment 1 NEM governance and market development, Section 1.3 Current policy and regulatory developments.

scheme and the South Australian Government's Residential Energy Efficiency Scheme (REES). Attachment A3 - Economic outlook provides more information about these policies.

The impacts of these policies were tested by the low growth scenario, which estimates a cut in emissions of 5% on 2000 levels by 2020.[55] Therefore, the carbon prices are assumed to be lower than the impact of the renewable energy certificate prices. This assumption showed the effect of the RET and/or REES policies on the electricity price forecasts was insignificant. Furthermore, the enhanced national RET scheme (which commenced on 1 January 2011) impacts relative to the previous RET policies were also shown to be irrelevant.

Consequently, the energy price forecasts did not incorporate the RET and/or REES implications as part of the assumptions/key drivers to be taken into account in the modelling process. However, the carbon price assumptions specified by AEMO scenarios are explicitly taken into account.

A1.1.3 South Australian Residential Energy Efficiency Scheme (REES)

The REES was established on 1 January 2009, as a condition for an energy provider to get a licence to sell electricity and gas in South Australia.

There are two types of targets under the REES:

- Greenhouse gas reduction – Energy providers are required to save a set number of tonnes of carbon dioxide equivalent (tCO2-e). Energy providers must also achieve a set proportion of these savings in low income households, and
- Energy audits – Energy providers are required to deliver a set number of energy audits to low-income households.

The government will concentrate on energy saving measures related to lighting, showerheads, ceiling insulation, draught proofing, fridges and freezers, heating and cooling systems, and water heaters.

The Minister for Energy has set targets for each of the next three years: reductions in greenhouse gas emissions of 155,000, 235,000 and 255,000 tonnes for 2009, 2010 and 2011 respectively (255,000 tonnes is equivalent to around 2% per annum of South Australia's electricity demand based on 2008 levels). The Minister will set targets for 2012 to 2014 during 2011.

Following KPMG's evaluation, AEMO considers that any increased commitment in the near future would be insignificant and uncertain, so this has not been directly taken into account as part of the forecast assumptions. The information related to the policy has been provided for descriptive purposes.

[55] KPMG included the impacts of the expanded RET scheme based on the RET legislation passed in August 2009 and the low growth scenario commencing 1 July 2013 as well as on 1 July 2014. The consultant also included the enhanced RET case (LRET/SRES) undertaking the changes to the scheme to commence 1 January 2011.

ATTACHMENT A2 - ECONOMIC OUTLOOK

A2.1 Economic outlook

Economic activity is strongly correlated with energy usage because increases in production usually require more energy and increases in income result in higher consumption, stimulating production and further energy use. Population growth also contributes directly to new electricity and gas connections as well as indirectly through the demand for more goods and services.

With these principles in mind, the forecasts presented within this report have been developed not only in the context of the economic outlook for South Australia, but of the broader Australian economy as well.

A2.1.1 Australian economy

Figure A2-1 shows Australia's historical and projected gross domestic product (GDP) growth for the low, medium and high growth scenarios. GDP grew between 3% and 4% each year from 2004/05 to 2007/08 driven by record commodity prices supported by a rising oil price, a weak US dollar and strong demand from developing countries.

GDP growth decreased sharply, but remained positive, during 2008/09 as a result of the global financial crisis. It increased to 2.2% in 2009/10 as the Australian economy started to show signs of recovery supported by fiscal and monetary stimulus, low interest rates and government incentives. Other key drivers were the strong performance of Asian countries and an improved trade balance, with a resurgent global demand for commodities pushing up Australia's terms of trade and contributing to growth in exports.

GDP growth is projected to increase for 2011/12 under all three scenarios. Despite disruptions to agricultural and mining output associated with flooding in the eastern states, agricultural and mining production is projected to increase, driving GDP growth, as these sectors recover over the second half of 2011. GDP growth is also forecast to temporarily increase due to construction activity required to rebuild flood-damaged infrastructure, houses and businesses.

Under the medium growth scenario, GDP growth is projected to return to approximately 3%, driven by solid export growth, recovering business investment and healthy consumption expenditure from ongoing household income growth. These drivers will be partially offset by increases in imports, which tend to reduce GDP growth, due to the Australian dollar remaining strong against its major counterpart currencies.

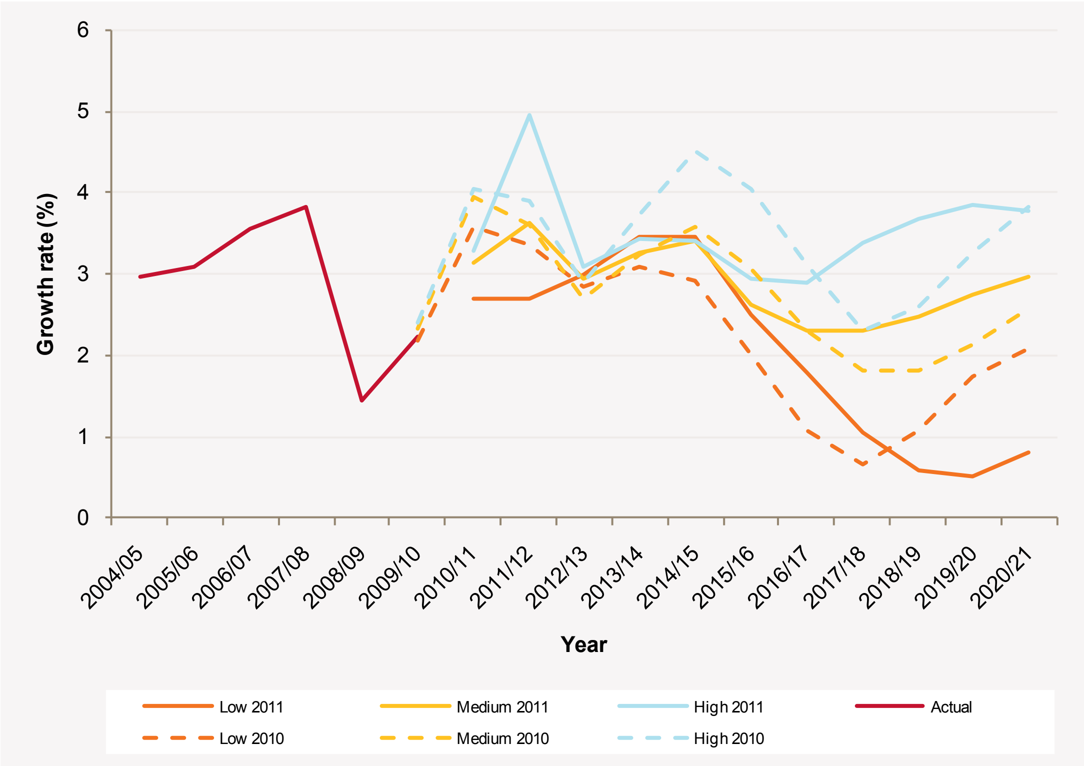
GDP growth varies significantly among the three scenarios after 2016/17 due to different assumptions for credit risk premiums that lead to a wide divergence in estimated levels of business investment. Under the medium and low growth scenarios a rise in risk premiums leads to a contraction in business investment. Under the high growth scenario, however, lower risk premiums lead to increased business investment, which increases GDP growth.

Comparison with 2010 projections

The 2010 projections assumed an even recovery from the global financial crisis in the first three to five years under all scenarios and then a slight divergence following a similar trend to an average GDP annual growth rate of 2.2%, 2.8% and 3.5% over the next 10 years, for the low, medium and, high growth scenarios, respectively.

The 2010 assumptions were focused on the speed of recovery from the global financial crisis as a key determinant of domestic economic growth over the short to medium term, incorporating a range of assumptions regarding credit availability, risk premiums and global growth. In this context, growth under all scenarios moderates between 2010/11 and 2012/13, reflecting a return to normal macroeconomic conditions following above trend growth associated with a recovery in 2010/11. This result was explained by the positive impact of stronger external demand and easing credit conditions. Later in the outlook period a continued divergence between the low, medium and high growth scenarios was expected to be underpinned by demographic and technological factors.

Figure A2-1— Projected real growth of Australian GDP



A2.1.2 South Australian economy

Table A2-1 summarises the average growth assumptions made for the key economic indicators for South Australia over the forecast period.

Table A2-1— Average annual growth of some key indicators over the next 10 years - South Australia

	Low	Medium	High
Gross domestic product	1.80	2.62	3.35
Total electricity price	0.47	0.73	1.01
Consumer price index	3.00	2.11	1.74
Population	0.63	0.85	1.05
Manufacturing output	-0.30	1.46	2.17

Figure A2-2 shows South Australia's historical gross state product (GSP) growth and the projected rates for the three scenarios for the energy forecasts. The South Australian economy slowed in 2009/10, as relatively resilient consumer demand was offset by a scaling back of production in South Australia's automotive manufacturing sector. Weak growth in 2009 also reflects the impact of weakened mining activity, as production at the Olympic Dam mine was impeded by the damage of a haulage shaft in October 2009.

However, growth is expected to pick up in the short run. Notably, GSP for 2009/10 was boosted by a solid performance by the agricultural sector, as favourable growing conditions across most regions saw winter crop production expand by an estimated 53%. Targeted stimulus measures have also contributed to growth, with the

Auatralian Government's First Home Owners Boost supporting a spike in dwelling investment in late 2009/10, which was translated into stronger construction activity in 2010/11.

A decline in the South Australian manufacturing industry will continue to impact negatively upon GSP. The strong Australian dollar has reduced wine and automobile exports from South Australia and is expected to continue to erode earnings for these sectors. However the forecasts assumed that growth in population would increase dwelling investment by the end of 2010/11. Combined with stronger business investment and growth in consumer spending, GSP growth is forecast at a relatively fast annual average pace of 3.1% over the next five years.

Under the low growth scenario, GSP forecasts are much slower than the baseline, reflecting weaker business investment due to higher risk premiums, as well as softer dwelling investment and a relatively poor trade performance.

Under the high growth scenario, strong population growth supports fast-paced growth in dwelling investment, whilst a lower risk premium facilitates greater business investment.

Over the medium to longer term, mining exports for the state are expected to grow strongly, which will offset slower growth in wine and automobile exports. Nearly half of South Australia's exports are destined for the power economies of Asia which have navigated the global financial crisis better than most regions. As a result, South Australia's vast minerals and energy resources, coupled with a strong commodity price outlook and the South Australian Government's commitment to investment in mining, should produce healthy growth in the South Australian exports sector.

South Australia has also been successful in developing a specialisation in the defence industry over the past five years, securing a number of large defence and security projects that are expected to support growth and create jobs and other associated flow-on opportunities.[56]

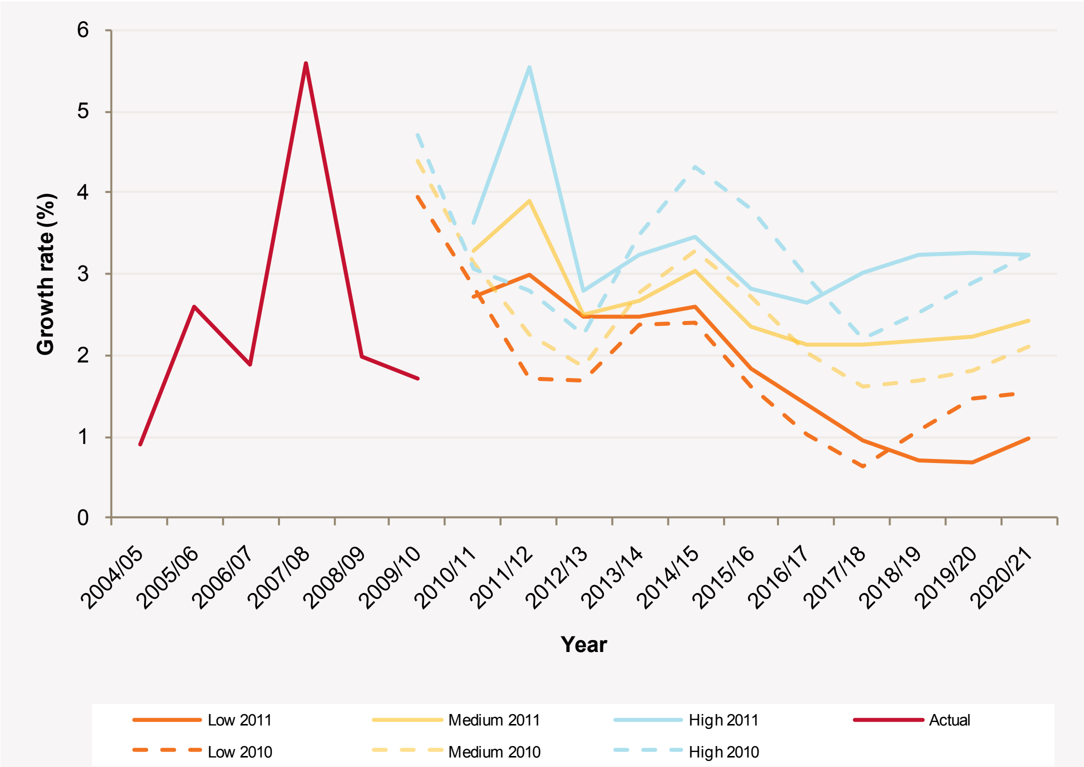
The historically high level of infrastructure spending in the state[57] is also expected to drive medium-term GSP growth. As a matter of fact, there are a number of major projects underway, including the potential expansion of the Olympic Dam.[58]

56 The largest Defence project in SA – the construction of three new warships - is expected to attract investment of $2 billion. In addition, one of three bidders for a $1 billion contract to manufacture 1,300 armoured vehicles for the Australian Army has committed to using South Australia as its base for manufacturing and support operations if it is awarded the contract, which would bolster employment and output for the state.

57 The SA government currently has a record $71.5 billion worth of major projects either underway or in the pipeline, including the Port Stanvac desalination plant and the electrification of the metropolitan train network.

58 The project has a long time horizon, with construction activity expected over an 11-year period.

Figure A2-2— Projected real growth of South Australian GSP



Comparison with 2010 projections

The 2010 forecasts assumed strong growth in 2009/10 followed by healthy but more moderate growth in 2010/11. The 2010 forecasts showed a quick recovery for the South Australian economy with strong growth in state final demand contributing to an expansion in GSP. This growth was explained by high levels of dwelling and business investment within the region, reflecting strong demand for housing as a result of gains in net interstate migration. Consumer demand was also expected to grow at a comparatively fast pace on the back of a strong labour market and a low level of unemployment. Growth was expected in the short run due to improved trade performance following renewed demand for mining outputs and a temporary boost to automotive exports in late 2009. The forecasts assumed that stronger consumer demand would result in further growth in the manufacturing sectors.

Over the longer term, net outflows of interstate migrants were expected to weaken South Australian population growth resulting in sluggish growth in the construction sector.

Assumptions for all the key indicators over the forecast period are summarised below in Table A2 - 2, Table A2 - 3 and Table A2 - 4 for the low, medium and high growth scenarios respectively.

Table A2 - 2— Key indicators for the next 10 years– low growth scenario

Low scenario	Population ('000s)	Gross State Product ($2008/09 m)	Consumer Price Index	Manufacturing output ($2008/09 m)
2009/10 actual	1,638	78,671	173.4	9,163
2010/11	1,651	80,814	177.4	9,139
2011/12	1,663	83,232	180.7	9,423
2012/13	1,674	85,287	183.6	9,697
2013/14	1,685	87,402	187.6	10,057
2014/15	1,695	89,665	193.8	10,525
2015/16	1,706	91,305	201.2	10,606
2016/17	1,716	92,586	209.3	10,406
2017/18	1,726	93,471	218.6	10,007
2018/19	1,736	94,142	227.9	9,521
2019/20	1,746	94,787	235.3	9,082
2020/21	1,755	95,704	240.0	8,812
Average annual forecast growth (% p.a.)	**0.63**	**1.80**	**3.00**	**-0.30**

Table A2 - 3— Key indicators for the next 10 years– medium growth scenario

Medium scenario	Population ('000s)	Gross State Product ($2008/09 m)	Consumer Price Index	Manufacturing output ($2008/09 m)
2009/10 actual	1,638	78,671	173.4	9,163
2010/11	1,653	81,250	177.6	9,252
2011/12	1,667	84,411	181.2	9,690
2012/13	1,681	86,517	184.6	9,803
2013/14	1,695	88,835	188.5	10,072
2014/15	1,710	91,530	193.1	10,498
2015/16	1,725	93,685	197.7	10,569
2016/17	1,739	95,679	201.7	10,494
2017/18	1,754	97,724	205.9	10,444
2018/19	1,768	99,863	210.2	10,439
2019/20	1,783	102,100	214.3	10,530
2020/21	1,797	104,573	218.2	10,735
Average annual forecast growth (% p.a.)	**0.85**	**2.62**	**2.11**	**1.46**

Table A2 - 4— Key indicators for the next 10 years– high growth scenario

High scenario	Population ('000s)	Gross State Product ($2008/09 m)	Consumer Price Index	Manufacturing output ($2008/09 m)
2009/10 actual	1,638	78,671	173.4	9,163
2010/11	1,655	81,519	177.5	9,314
2011/12	1,670	86,040	181.0	10,045
2012/13	1,687	88,447	184.9	9,950
2013/14	1,705	91,310	189.3	10,144
2014/15	1,723	94,470	193.3	10,480
2015/16	1,742	97,129	196.4	10,600
2016/17	1,760	99,692	198.2	10,680
2017/18	1,779	102,688	200.2	10,902
2018/19	1,798	106,019	202.8	11,125
2019/20	1,818	109,486	206.1	11,353
2020/21	1,837	113,035	209.5	11,577
Average annual forecast growth (% p.a.)	**1.05**	**3.35**	**1.74**	**2.17**

Key indicators for 2011 forecasts include:

- **Agriculture:** the South Australian agriculture sector, particularly wine grape production, has grown to constitute a large proportion of output. However, the outlook for the sector is relatively pessimistic, as a high Australian dollar is expected to hurt efforts to grow sales of Australian wines in the US and European markets.
- **Mining:** Mining output for the state is forecast to grow at a pace of 5.1% per annum over the short run, reflecting expected growth in output from the Olympic Dam mine. Greater exploration and development activities over the medium term should support an increase in production over the coming years.
- **Housing:** Dwelling construction is expected to rise in 2010/11 in line with recent population growth, and expansion in the services sector is expected to mirror that in the wider national economy.
- **Population:** While population growth for South Australia remains well below the national average, recent years have seen the growth rate accelerate on the back of increases in net overseas migration. In the year to March 2010, South Australia experienced its most rapid population growth since 1975 at 1.3%. Population growth for the state is now expected to slow in line with a tightening of federal migration policies. Declining fertility is also expected to constrain population growth in the state; South Australia has a lower fertility rate than the national average as it has an older population.

ATTACHMENT A3 - EMBEDDED GENERATORS

Table A3-2 and Table A3-3 below summarise South Australian small (embedded) generators. The following abbreviations are used to describe the source type:

Table A3-1 — Generation technology abbreviations

Abbreviation	Description
ST	Steam turbine
RCP	Reciprocating engine
GT	Gas turbine
Cogen	Cogeneration

Table A3-2 — Market embedded generators (AEMO settles electricity sales)

Scheduled generators (Subject to central despatch with generator greater than 30 MW)			**Non-scheduled generators (Less than 30 MW or greater than 30 MW where it is not practicable to dispatch or the output is intermittent)**		
Operator	**Capacity MW**	**Source type**	**Operator**	**Capacity MW**	**Source type**
Infratil Energy Australia Pty Ltd Angaston	30 x 1.67 MW	Diesel RCP	Emagy Pty Ltd Lonsdale	12 x 1.67 MW	Diesel RCP
			Infratil Energy Australia Pty Ltd, Pt Stanvac A and Pt Stanvac B	36 x 1.8 MW	Diesel RCP
			International Power, Canunda, South East	23 x 2 MW	Wind turbines
			Transfield Services Infrastructure, Starfish Hill, Fleurieu Peninsula	23 x 1.5 MW	Wind turbines
			Joint Venture (SA Water & Hydro-Tasmania)	1.86 MW	Hydro
			Tatiara Meatworks Bordertown Non-Export	1 x 0.48 MW	Diesel RCP

Table A3-3 — Non-market generators (Sells to local retailer or to a customer at the connection point)

Operator/Owner	Location	Export into the National Grid	Capacity (MW)		Source type	
			Renewable	Non-renewable	Renewable	Non-renewable
One Steel Manufacturing	Whyalla	Non-export	-	66.5 MW (2 x 4.5 MW GT, 1 x 15 MW, 1 x 30 MW & 1 x 12.5 MW ST)	-	Natural gas/fuel oil/coke gas
Energy Developments	Wingfield 1	Export	2.1 MW RCP	-	Landfill gas	-
Energy Developments	Wingfield 2	Export	3.9 MW RCP	-	Landfill gas	-
Energy Developments	Highbury	Export	1 MW RCP	-	Landfill gas	-
Energy Developments	Pedler Creek	Export	3.1 MW RCP	-	Landfill gas	-
Energy Developments	Tea Tree Gully	Export	1 MW RCP	-	Landfill gas	-
SA Water	Bolivar Waste Water Treatment Plant	Non-export	3.5 MW GT	-	Sewage gas cogen	-
SA Water	Glenelg Waste Water Treatment Plant	Non-export	1.95 MW RCP	-	Sewage gas cogen	-
AGL	Cooper's Brewery/AGL Regency Park	Export	-	4.4 MW GT	-	Natural gas cogen
St. Andrew's Hospital	Adelaide	Non-export	-	0.5 MW RCP	-	Natural gas cogen
Royal Agricultural & Horticultural Society	Adelaide Showgrounds	Export	1.0 MW	-	Solar	-
Adelaide Airport Limited	Adelaide Airport	Export	0.11 MW	-	Solar	-
SA Government	Adelaide SA Parliament House	Export	0.02 MW	-	Solar	-
SA Government	Adelaide North Terrace Museum	Export	0.02 MW	-	Solar	-
SA Government	Adelaide State Library North Terrace	Export	0.02 MW	-	Solar	-
SA Government	Adelaide SA Art Gallery	Export	0.02 MW	-	Solar	-
Ashford Community Hospital	Adelaide	Export	0.22 MW	-	Solar	-

Operator/Owner	Location	Export into the National Grid	Capacity (MW)		Source type	
			Renewable	Non-renewable	Renewable	Non-renewable
Campbelltown Council	Campbelltown Library	Export	0.05 MW	-	Solar	-
Campbelltown Council	Campbelltown Office Building	Export	0.03 MW	-	Solar	-
Motor Traders Association	Royal Park Workshops	Export	0.1 MW	-	Solar	-
Adelaide City Council	Adelaide - U Park Rundle Street	Export	0.05 MW	-	Solar	-
Adelaide City Council	Adelaide Central Markets	Export	0.05 MW		Solar	-
Adelaide City Council	Adelaide Bus Centre	Export	0.05 MW	-	Solar	-
Conservatory on Hindmarsh Square Pty Ltd	Adelaide - Conservatory on Hindmarsh Square	Export /Solar - Non-export/cogen	0.01 MW	0.07 MW	Solar	Natural gas cogen
Ashford Community Hospital	Ashford Hospital	Non-export	-	0.55 MW RCP	-	Diesel cogen
NE Community Hospital	Campbelltown	Non-export	-	0.24 MW	-	Natural gas cogen
Onkaparinga Council	Noarlunga Aquatic Centre	Non-export	-	0.14 MW RCP	-	Natural gas cogen
Regency Institute of TAFE	Regency Park	Non-export	-	0.55 MW RCP	-	Natural gas
SA Research & Development Institution	Urrbrae	Non-export	-	0.54 MW RCP	-	Natural gas
Women's & Children's Hospital	North Adelaide	Non-export	-	1.92 MW RCP	-	Natural gas cogen
Gawler Health Service	Gawler	Non-export	-	0.23 MW RCP	-	Natural gas
Penrice Soda Products	Osborne	Non-export	-	1.25 MW ST	-	Natural gas cogen
Botanical Gardens[a]	Kent Town	Non-export	-	0.06 MW RCP	-	Natural gas cogen
Origin Energy[b]	Adelaide	Non-export	-	0.31 MW RCP	-	Natural gas
San Remo Macaroni P/L	Windsor Gardens	Non-export	-	0.63 MW RCP	-	Natural gas cogen
Tan Pty Ltd[c]	Adelaide	Non-export	-	0.48 MW RCP	-	Natural gas cogen
SA Health	Bedford Park - Flinders Medical Centre	Non-export	-	1.2 MW RCP	-	Natural gas cogen

Operator/Owner	Location	Export into the National Grid	Capacity (MW)		Source type	
			Renewable	Non-renewable	Renewable	Non-renewable
SA Health	Modbury Hospital	Non-export	-	0.25 MW RCP	-	Natural gas cogen
SA Health	Ceduna District Hospital	Non-export	-	0.4 MW RCP	-	Diesel
d'VineRipe Glasshouse	Two Wells	Non-export	-	0.48 MW RCP natural gas cogen/ 2 x 1.0, 1 x 0.36 MW RCP Diesel)	-	Natural gas cogen and diesel
Department of Defence (DSTO)	Salisbury	Non-export	-	2.3 MW RCP	-	Natural gas
Department of Defence (HNA)	Edinburgh RAAF Base	Non-export	-	4 MW (2 x 0.6 MW, 1 x 1.2 MW and 1 x 1.6 MW RCP)	-	Diesel

a. Status of Plant unverified.

b. Status of Plant unverified.

c. Status of Plant unverified.

ATTACHMENT A4 - INVESTMENT TRENDS

A4.1 Load and price duration curves

The following load (demand) and price duration curves show the frequency that a particular level of demand or price occurs in each half-hour of the year. The horizontal axis represents the part of the year the demand or price is at or above the level indicated on the vertical axis.

Figure A4-1 and Figure A4-2 show the load and price duration curves for South Australia for the financial years 1999/2000 to 2010/11.

Figure A4-1 is based on demand, which includes scheduled, semi-scheduled, and non-scheduled generation. Demand reductions due to demand-side participation (DSP) have been added back to show the original load.

While demand for the last three years has remained approximately the same, the load duration curve shows slight variations as a result of record demands in 2009/10, demonstrated by the more pronounced peak in the 0%-10% range as a result of the long hot summer experienced that year. This is in contrast to the moderate 2010/11 summer, which is reflected by the slightly reduced peak for that year in the same range. Demand for the rest of 2010/11 was higher more frequently than during 2009/10.

Figure A4-1 — South Australian load duration curves

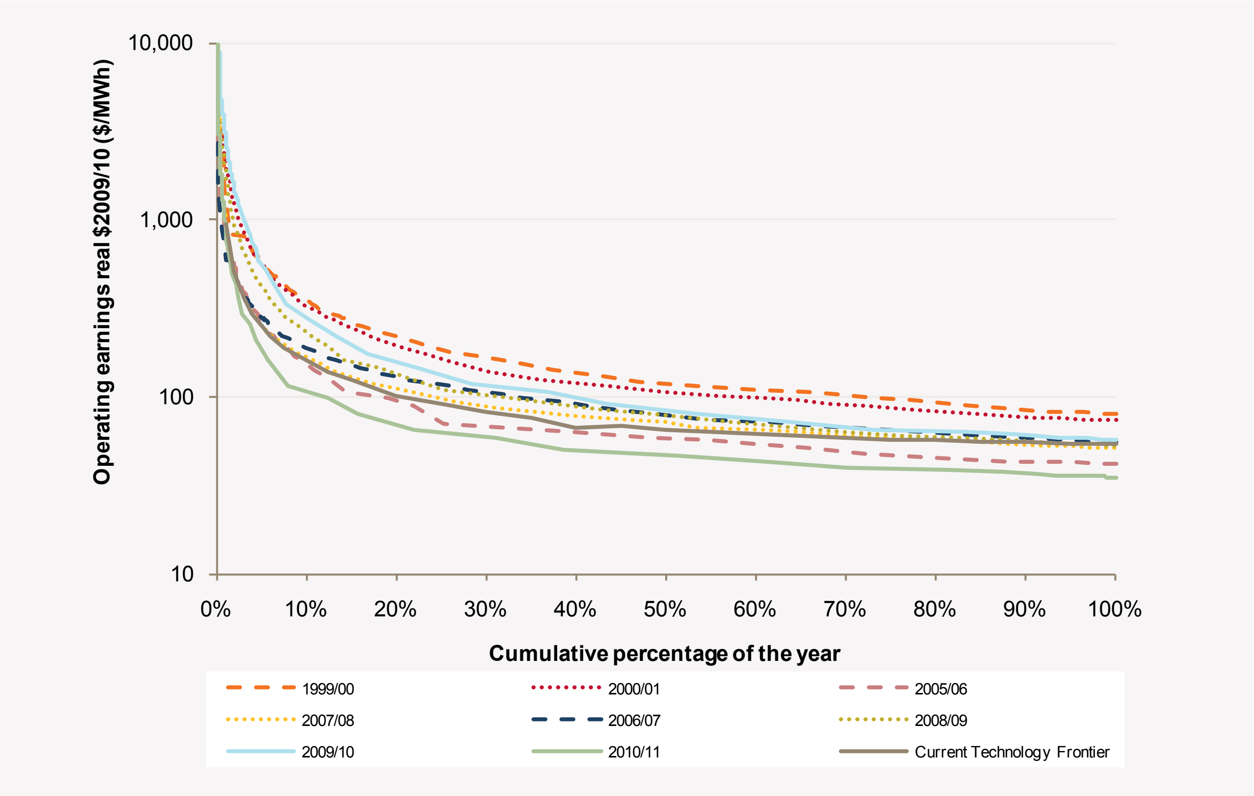


Table A4-1 lists the load factors for 2002/03 to 2010/11 financial years.

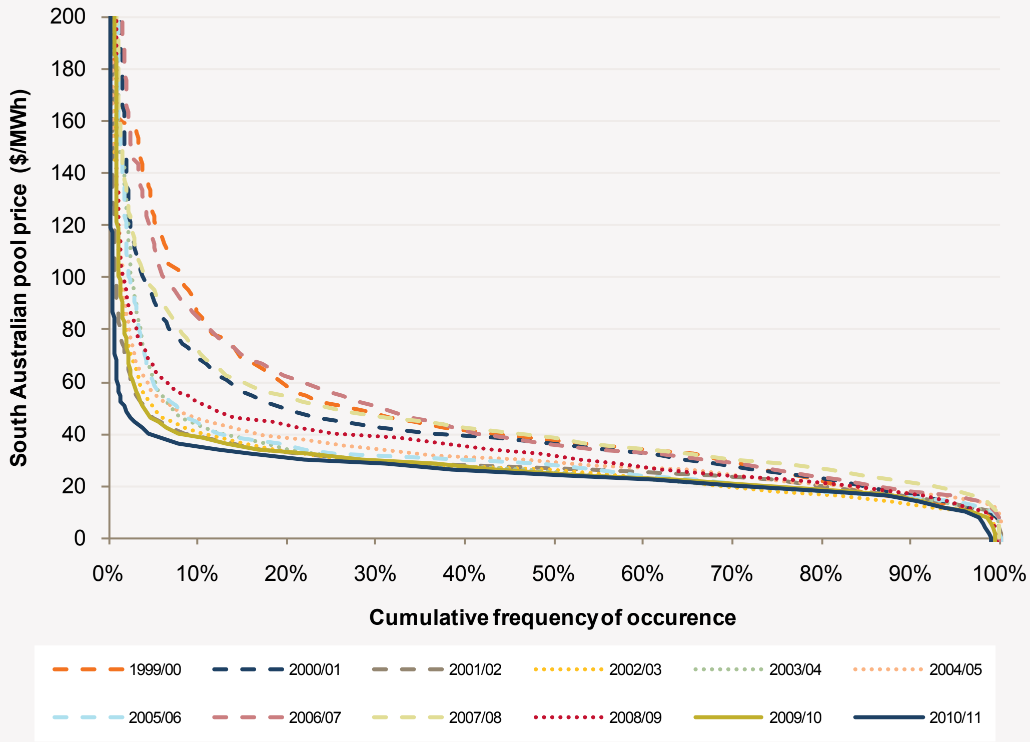
Table A4-1 — South Australian load factors[a]

	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11
Load factor	0.53	0.57	0.56	0.52	0.56	0.48	0.50	0.49	0.52

a. The load factor is the ratio of the average demand to the peak demand.

Figure A4-2 shows the price duration curves for South Australia.

Figure A4-2 — South Australian price duration curves



The curve for 2010/11 is relatively flat for most of the year, indicating that prices were lower than in previous years for most of the time (apart from the peak in the 0% to 5% range).

Figure A4-3 shows the price duration curve in real 2009/10 dollars, which demonstrates the relatively low prices that occurred during 2010/11, when prices were between (zero) 0 $/MWh and 40 $/MWh for approximately 90% of the time.

While not shown on the figure, there were 154 occasions where the wholesale price fell below (zero) 0 $/MWh during 2010/11. This compares to 86 occasions during 2009/10.

On 14 occasions the price was greater than 1,000 $/MWh during 2010/11 (of which nine were greater than 5,000 $/MWh), compared to 73 and 47 occasions (respectively) during 2009/10.

Both the 2009/10 and 2010/11 curves are lower than previous years, further emphasising the lower prices during both years.

Historical price is one of a number of indicators of market opportunity for new investment. The price duration curves for the 1999/00, 2000/01, 2006/07, and 2007/08 financial years show market price conditions where price-driven investment opportunities existed for new generation. These conditions are demonstrated by the curves being higher and showing relatively gentler slopes, indicating that prices between 20 $/MWh and 80 $/MWh occurred significantly more frequently.

Figure A4-3 — South Australian price duration curves in real 2009/10 dollars

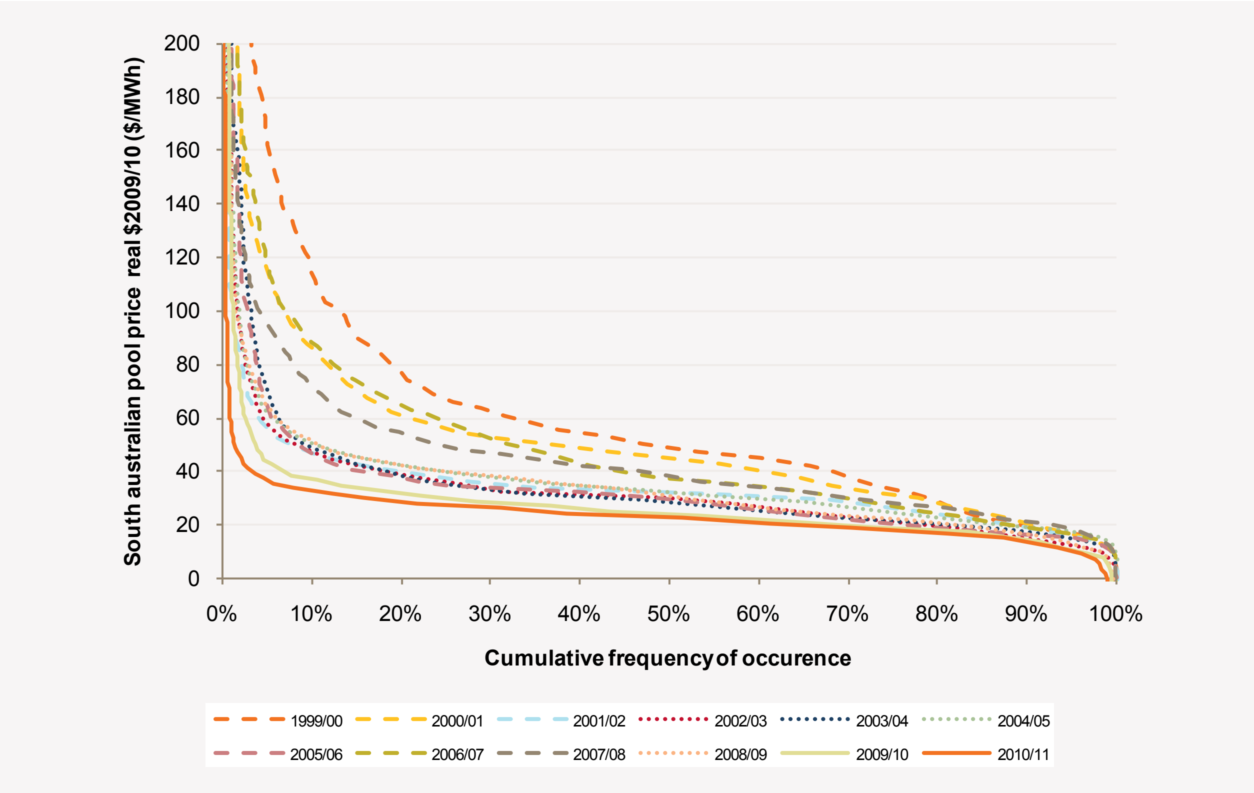


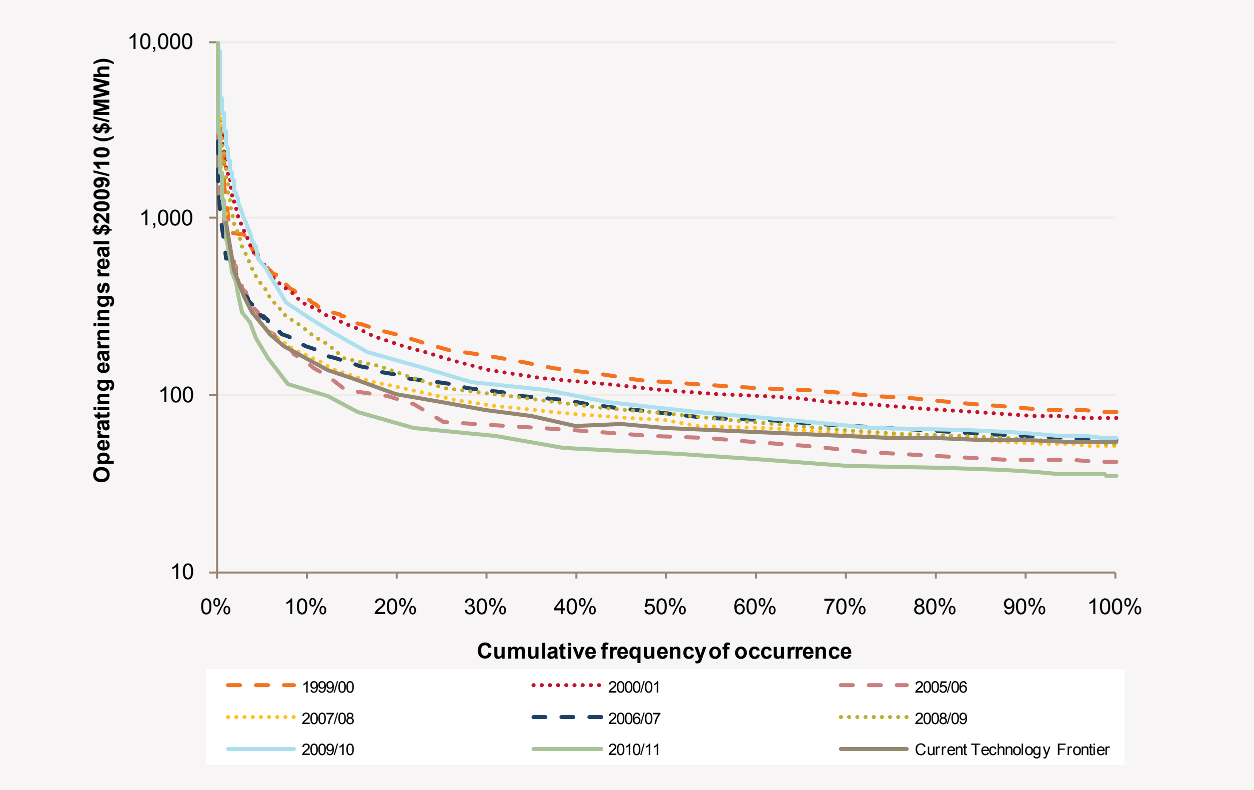
Figure A4-4 shows the South Australian earnings duration curves for the period 1999/00 to 2010/11 (in real 2009/10 dollars), demonstrating the potential wholesale market earnings available in South Australia. The curves are generated by summing the real earnings over time from the wholesale market price.

Although not an absolute representation of the potential opportunities, the figure shows the potential earnings an ideal, perfectly reliable 1 MW generator can receive if operated unconstrained when the price was at or above a particular level. This also assumes that, being so small, its contribution to the energy supply has no impact on the underlying wholesale market price or the behaviour of other market participants.

For example, if a 1 MW generator operated every hour the price was above 100 $/MWh, its earnings would be the sum of all of the prices 100 $/MWh. Similarly, if the same 1 MW generator operated continuously for the full year, independent of the price, it would earn the sum of all of the prices for the year which would be the same as the time-weighted (or simple average) wholesale market price.

Figure A4-4 highlights that the potential wholesale market earnings during 2010/11 were lower than at any previous time. Frequent negative prices during 2010/11 (to the end of March 2011) lowered the average price. Analysis of the negative price periods and demand shows that these periods potentially cost in the order of $23 million, or approximately 2% of the earnings of the generators in the region.

Figure A4-4 — South Australian earnings duration curves in real 2009/10 dollars



A4.2 Long-run cost of operation and the technology cost frontier

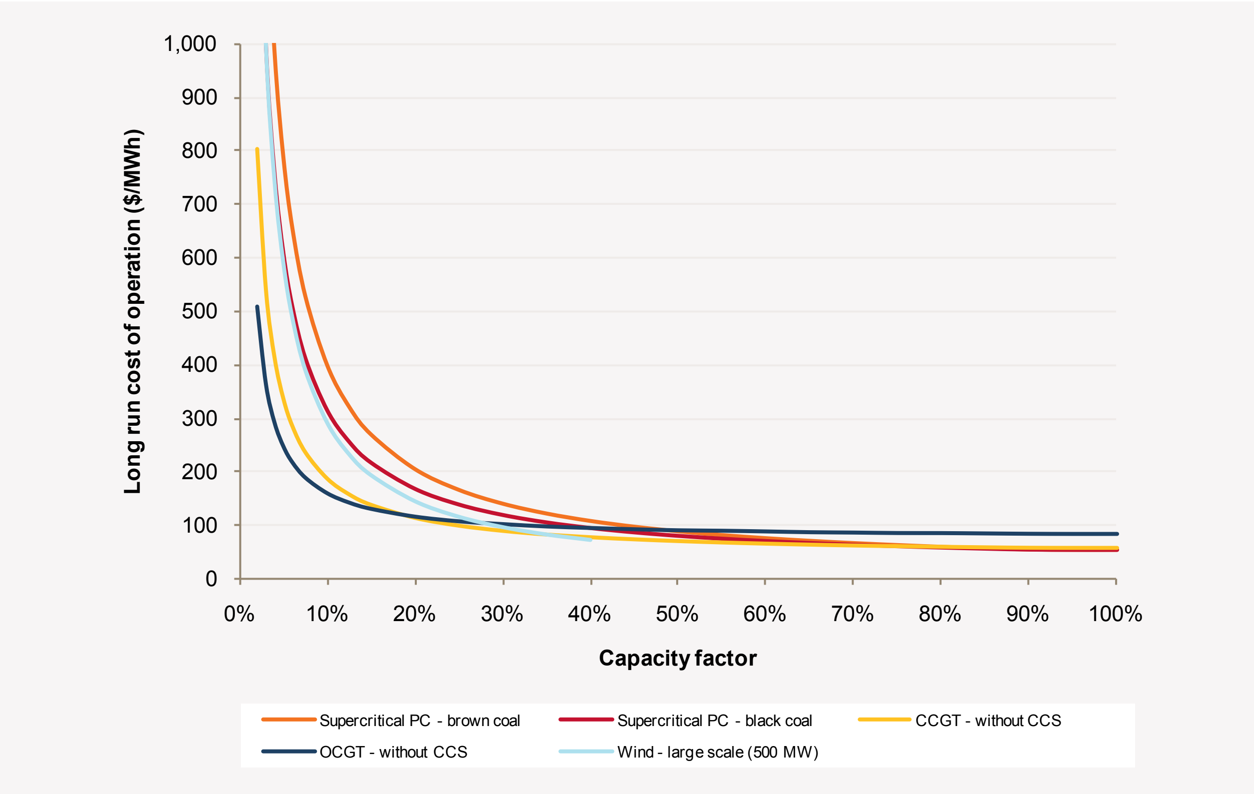
The long-run cost of operation covers a generating system's full life-cycle (whole-of-life), including its financing costs, and is often quoted as a single figure in dollars per megawatt hour ($/MWh), which is an abbreviation of the cost of operation for an assumed level of annual output.

For example, if a generating system's long-run cost of operation is approximately 40 $/MWh, this value only applies for a given set of financing assumptions, fuel costs, and specific capacity factor. If the capacity factor changes, however, then the recovery of fixed costs and financing changes will change the price it needs to receive to cover its costs. If the new capacity factor is significantly smaller than that assumed initially, then the long-run cost of operation cost is significantly higher.

As a generating system's assumed output changes, so does its long-run cost of operation, and the cost for each level of output can be calculated and represented graphically on a cost versus capacity factor plot.

Figure A4-5 shows the long-run cost of operation for a number of different technologies that either currently operate in South Australia or are potentially suitable for new entry generation candidates. Where PC refers to pulverised coal (PC).

Figure A4-5 — Long-run cost of operation



Different technologies can have different long-run costs of operation for the same level of output due to differing capital and operating costs for the same assumed financing arrangements.

For example, at high capacity factors, combined-cycle gas turbine (CCGT) and supercritical pulverised (black and brown) coal generation has a lower long-run cost of operation than open-cycle gas turbine (OCGT) generation (the opposite applying for low capacity factors).

Large-scale wind generation is also potentially cheaper at a 40% capacity factor than CCGT, OCGT, or supercritical pulverised coal (though this is potentially misleading with respect to potential earning ability, as CCGT and supercritical pulverised coal routinely operate continuously at capacity factors greater than 40%, while there are few, if any, wind farm sites that make this possible).

Technology cost frontiers

Table A4-2 lists the economic parameters used to calculate the long-run cost of operation and the technology cost frontiers. Fuel costs, capital and operating costs, and maintenance rates and costs are defined in the 2011 National Transmission Network Development Plan (NTNDP) Consultation, (published in January 2011).

Table A4-2 — Economic parameters for calculating the long-run cost of operation and the technology cost frontiers

Economic parameter	Value
Inflation (% CPI)	2.50
Equity beta	1.50
Gamma	0.50

Economic parameter	Value
Debt proportion of funding (% Gearing)	50
Risk-Free Rate	4.3%
Debt Premium	2.0%
Market Premium	3.0%
Tax rate (% per annum)	30%
Effective Tax Rate (% per annum)	22.5%
Kd (cost of debt, nominal % per annum)	6.3%
Ke (cost of equity, nominal) excludes Beta	7.3%
Return on Equity Includes Beta	8.8%
WACC[a] (post-tax, nominal) Beta =1.5 Gamma =0.5	6.24%
WACC (post-tax, Real) Beta =1.5 Gamma =0.5	3.65%
WACC (pre-tax, nominal) Beta =1.5 Gamma =0.5	8.05%
WACC (pre-tax, Real) Beta =1.5 Gamma =0.5	5.42%

[a] Weighted average cost of capital (based on the 'Officer' formula).

A technology cost frontier shows the lowest long-run cost of operation for a group of technologies. It is determined by selecting the lowest long-run cost of operation for any technology within the group for a given capacity factor.

Figure A4-6 shows the technology frontier and long-run cost of operation for the currently available generation technologies, or the lowest-cost technologies commonly selected for new generation projects in Australia (wind, CCGT, OCGT, and PC).

Figure A4-7 shows the technology frontier and long-run cost of operation for the low emission technologies currently available (wind, CCGT, OCGT, and pulverised coal with carbon capture and storage (CCS)) on the same basis as Figure A4-6.

For consistency, financial assumptions and costs are constants, and the analysis does not incorporate a penalty price for carbon emissions.

Figure A4-6 — Currently available technology cost frontier

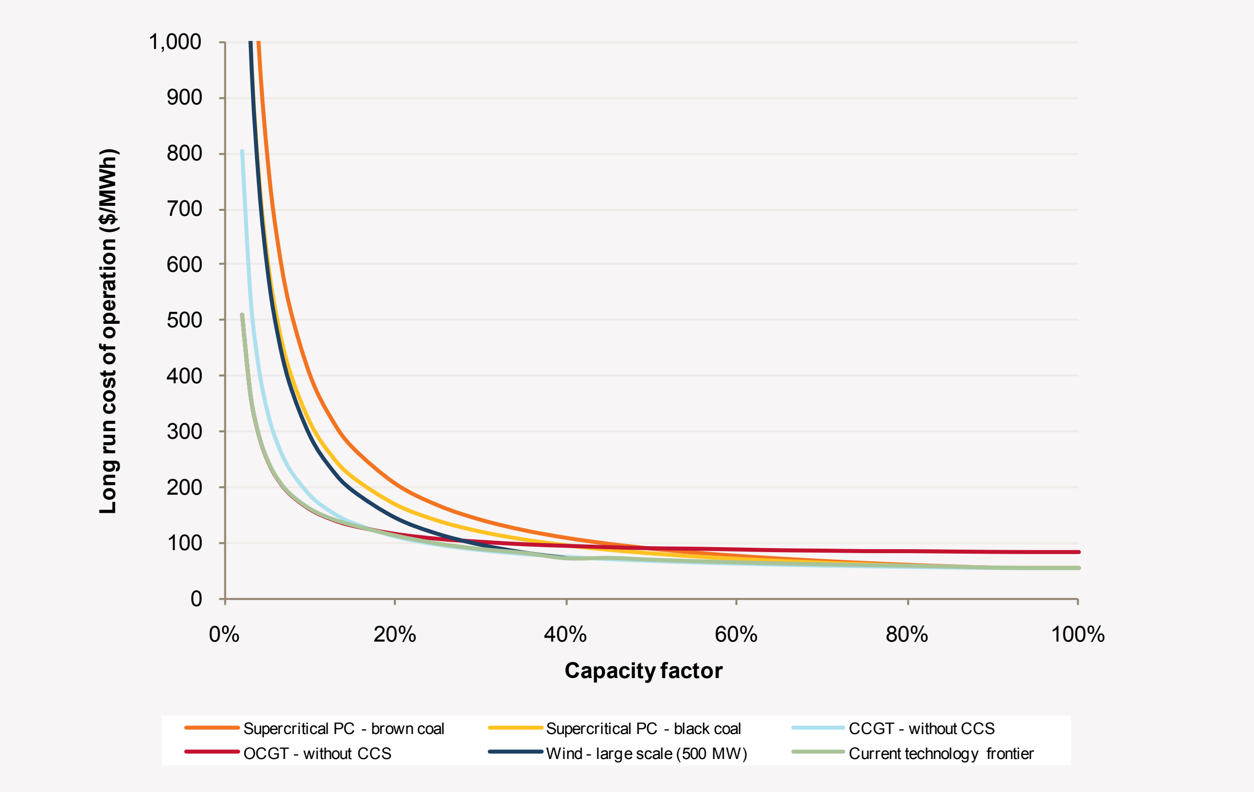
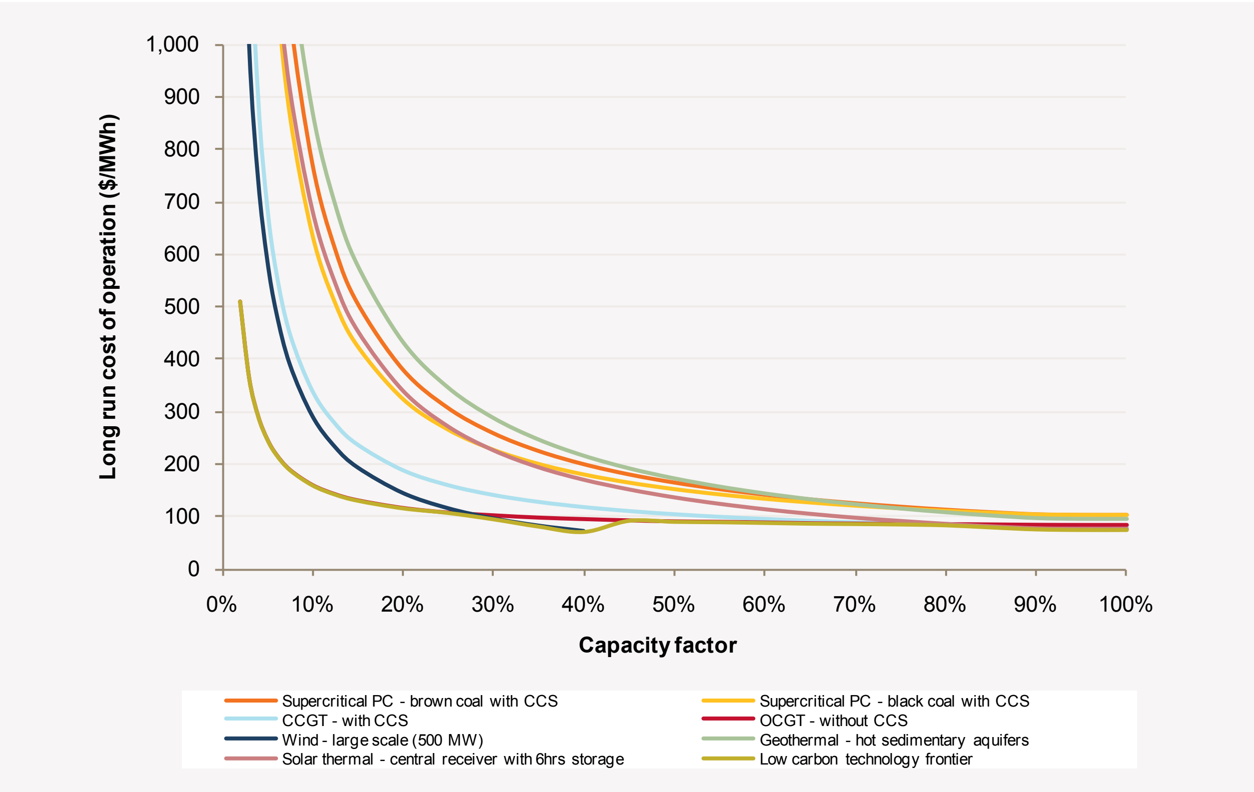


Figure A4-7— Low emission technology cost frontier



For low capacity factors, the technology cost frontier for currently available and low emission technologies are similar due to the inclusion of OCGT without CCS.

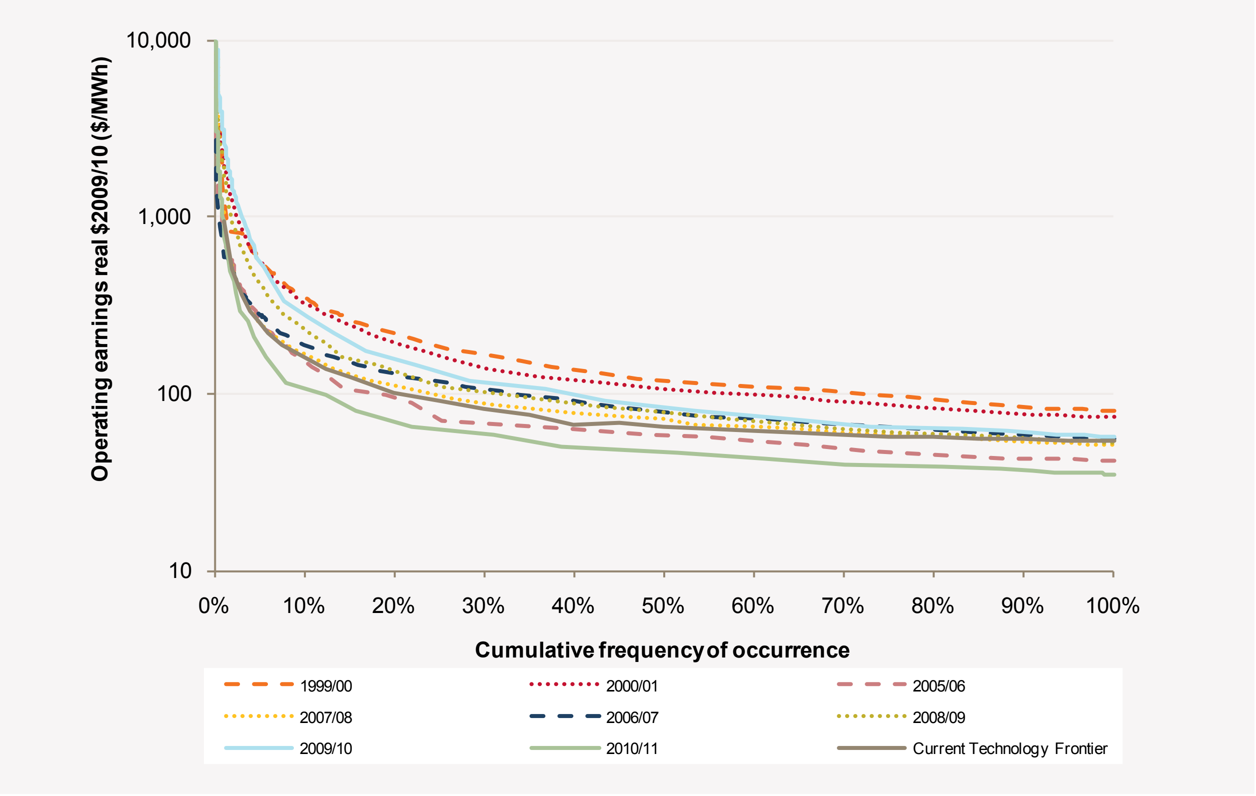
At higher capacity factors, however, the additional cost of CCS (omitted from the currently available technology cost frontier) increases the long-run cost of operation by approximately 30 $/MWh.

Supercritical black coal generation with CCS demonstrates a lower long-run cost of operation than solar thermal with storage and geothermal generation, until the capacity factors approach 90%. All three technologies demonstrate a lower long-run cost of operation than supercritical brown coal generation with CCS for all capacity factors.

Figure A4-8 shows the technology cost frontier overlayed onto the earnings duration curve from Figure A4-4, showing the lower earnings duration for the 2010/11 financial year. The 2009/10 earnings curve is higher than the technology cost frontier, indicating there was a potential opportunity for new technology investment.

Most of the revenue difference between 2009/10 and 2010/11 may have been driven by the hot summer experienced in 2009/10 that year and the increased penetration of wind generation. Summer temperature variability will always pose a significant issue with respect to wholesale market revenue certainty, particularly for intermittent and peaking plant. Generators normally manage this risk through the contract market.

Figure A4-8 — Technology frontier and earnings duration curve (overlay)



A4.3 Low market prices

South Australian wholesale electricity market prices are lower than they have been since the start of the National Electricity Market (NEM), and the gap between the price received by fossil-fuelled and renewable generation has widened.

Wind generation in South Australia is generally dominated by fronts from the south west. This frequently results in a simultaneous and consistently high output from all the region's wind farms. Wind farms typically offer their capacity into the market at low or negative prices. Consequently, when the wind is strong and all of the wind farms in the state are operating at high levels of output, the market price may drop. Under these conditions, fossil-fuelled generation can manage their risk positions with contracts that offer protection from low prices.

Alternatively, a lack of wind can result in a simultaneous and consistently low output from all the state's wind farms. When this occurs, demand is supplied by fossil-fuelled generation, potentially leading to higher prices.

Table A4-3 shows the volume-weighted wholesale market prices for South Australia, calculated from the market systems.

Table A4-3 — Volume-weighted wholesale market prices for South Australia since 2004

Financial year	Renewables		Fossil fuelled		South Australian market		Full year time-weighted ($/MWh)
	Full year ($/MWh)	Summer ($/MWh)	Full year ($/MWh)	Summer ($/MWh)	Full year ($/MWh)	Summer ($/MWh)	
2003/04	33.09	40.56	39.96	50.43	43.85	61.09	32.57
2004/05	38.47	56.72	44.56	67.50	44.61	67.92	33.33
2005/06	32.57	39.59	43.91	67.50	43.26	65.78	34.34
2006/07	49.69	51.55	58.71	67.21	58.35	66.43	62.95
2007/08	63.31	63.94	102.01	149.92	98.46	142.32	55.95
2008/09	46.39	91.80	70.50	165.34	67.16	155.12	38.76
2009/10	47.39	77.43	86.69	140.98	80.17	131.01	28.44
2010/11[a]	22.82	29.75	50.78	91.74	45.17	78.60	27.63

a. The values for the 2010-11 financial year are based on the period 1 July 2010 to 1 April 2011.

Investment in new generation in South Australia has slowed this year. Information from proponents attributes this to a number of concurrent market conditions including, but not limited to, low market prices, insufficient demand, and uncertainty with regard to environmental policies. The majority of new projects involve renewable or peaking generation, but most are in the early development stage. The preceding analysis would appear to substantiate the proponent's information.

[This page is left blank intentionally]

ATTACHMENT A5 - VALUE OF CUSTOMER RELIABILITY

A5.1 Value of Customer Reliability

The Value of Customer Reliability (VCR) is the value consumers place on having a reliable supply of electricity, and is equivalent to the cost to the consumer of having that supply interrupted for a short time.

Since improved reliability is provided in varying degrees by different types of electricity infrastructure investments, planners need to understand the value of reliability improvements associated with particular projects. However, because consumers do not have an explicit choice regarding the level of reliability they receive with their electricity supply, there is no market price for reliability.

Different approaches have been developed around the world to quantify the VCR concept, which has also been referred to variously as 'value/cost of unserved energy', 'value of lost load', 'outage cost', 'customer cost of service interruption', and 'value of supply security'. These include:

- model-based approaches, such as loss-of-income measures as a proxy for customer valuation, or cost-of-supply alternatives where standby generation is assumed to be incurred, and
- survey-based approaches, where a sample of customers' willingness to pay is either elicited by direct questioning about costs incurred or by indirect choice questioning.

The approach to VCR measurement in Victoria is based on a mix of direct and indirect survey methods.

The Australian Energy Market Operator (AEMO) is currently reviewing the existing values and future development of VCR measures for all the regions, including Victoria. The key motivation for this review (foreshadowed in the 2009 National Transmission Statement[59]) is the lack of any consistent and explicit regional VCR measures, other than for Victoria.

The VCR review activities to date include a report by Oakley Greenwood[60], followed by public consultation. AEMO held a public forum to discuss the development of national VCRs in December 2010. Additional written feedback was then sought and submissions were received which identified several issues. These include the following:

- The composition of the VCR with respect to lengths of interruptions, breakdown of customer categories, coverage of end-uses and inclusion of transmission-connected customers.
- The uses to which the VCR measures might be put by others, including distribution network service providers, both for network planning and regulatory performance measures, and the AEMC, for setting reliability standards, as well as by transmission planners, for transmission planning, as intended by AEMO.
- Methodological issues, including the need for new region-specific survey data, continued use of previous survey methods, the costs and transparency of the estimation process, the relation between estimated VCR and the income of the survey respondents, the timing and frequency of updated estimates and the elimination of possible over-estimation due to the inclusion of wealth transfers.
- The future network charges implications of the VCR, given that current regulatory regimes almost guarantee that a higher VCR leads to greater network investment and higher charges to pay for it, without addressing the generally increasing ratio of peak demand to average demand.

[59] AEMO. 2009 National Transmission Statement. http://www.aemo.com.au/planning/nts2009.html. Accessed 10 May 2011.

[60] See: "Valuing Reliability in the National Electricity Market", http://www.aemo.com.au/planning/vcr.html.

- The possible collaboration with AEMO of interested parties in a joint process to update the VCR, in order to cover some of the costs and ensure an eventual VCR outcome that is fit for multiple purposes.
- Other issues including the relationship between the market price cap and the VCR; whether AEMO is in fact the most appropriate organisation to develop the VCR further; the valuation of high impact/low probability events; the recognition that most lack of reliability events occur in distribution, rather than in transmission networks; and the possible underestimation of social disruption costs and the ways in which more demand response capacity would diminish measured VCRs and vice versa.

AEMO published an issues paper addressing the issues raised and the material in the Oakley Greenwood report for further public comment in mid June 2011. A final report will be published on the AEMO website in early July. In the final report AEMO recommends the best approach and timeframe to calculate and subsequently update a set of regional VCRs for high level electricity transmission planning.

The Essential Services Commission of South Australia commissioned a report in 2003 in order to understand consumer preferences, and to determine quality of supply performance indicators for ETSA Utilities. This review was able to estimate the value to the average consumer of reducing either the duration of power interruptions or the number such interruptions as a percentage of the average bill. However it stopped short of providing planning values for the cost of unserved energy. Unfortunately estimates of the cost of unserved energy, or VCR, only exist for Victoria. Recently AEMO has reviewed and sought industry views on future measurement of VCR for all NEM regions. A report on national VCR measurement will be published on the AEMO website by the end June 2011.

APPENDIX A - AEMO'S ADVISORY FUNCTIONS

The formation of the Australian Energy Market Operator (AEMO) led to a South Australian Government request for AEMO to deliver certain planning functions previously provided by the Electricity Supply Industry Planning Council of South Australia (ESIPC). Described in Section 50B of the National Electricity Law as 'additional advisory functions', in some cases they are provided by ElectraNet or AEMO publications other than the SASDO. Where this is the case, a consistent level of information is provided across all regions. The following list details the functions AEMO performs for the South Australian Government in relation to South Australia's declared power system (the respective AEMO planning publication(s) that provides each function is also listed):

- PSR01: interface transmission/distribution (National Transmission Network Development Plan (NTNDP[61])).
- PSR02: connection points (ElectraNet Annual Planning Report).
- PSR03: supply-demand balance (Electricity Statement of Opportunities (ESOO)).
- PSR04: generation forecast including existing and potential future electricity supply options (SASDO and ESOO).
- PSR05: current and forecast future congestion on the South Australian transmission network (NTNDP[61]).[62]
- PSR06: Electricity generation historical fuel use and future electricity generation fuel availability assessment (SASDO).
- PSR07: estimated greenhouse gas emissions for South Australian electricity usage (SASDO).
- PSR08: Supply/Demand forecasts, and national reliability guideline impacts (ESOO).
- PSR09: seasonal peak and aggregate energy usage, and historical and forecast future demand for electricity (SASDO).
- PSR10: significant future fossil fuel generation projects (SASDO).
- PSR11: significant renewable energy generation projects (SASDO).
- PSR12: historical generation for South Australian generators (SASDO).

[61] AEMO. National Transmission Network Development Plan. 2010. www.aemo.com.au/planning/ntndp.html. Accessed 7 June 2011.

[62] This item is partially met by the ElectraNet Annual Planning Report.

[This page is left blank intentionally]

APPENDIX B - TECHNOLOGY DISCUSSION

This appendix presents information about existing and emerging electricity generation technologies relevant to South Australia.[63] It aims to present background information for each technology, highlighting how they are likely to change over time. Table B-1 provides a brief description of each technology discussed and its relevance to South Australia. It is likely that as these technologies mature, the generation profile will change. Technologies such as subcritical coal and diesel generation have not been included in this discussion as there is little to report in terms of development.

Table B-1 — Generation technologies and their relevance to South Australia

Generation technology	Relevance to South Australia
Integrated [coal] gasification and combined cycle (IGCC)	Almost 21% of conventional thermal generation capacity in South Australia is from coal. There is an early proposal to develop an IGCC plant in Arckaringa in the state's far north.
Carbon capture and storage (CCS)	This technology could be used to reduce the emissions of several existing and emerging generation technologies in South Australia.
Supercritical pulverised coal	Depending on the potential development of a carbon tax, South Australia has coal deposits that are still being investigated for electricity generation purposes.
Gas turbines (GT)	Use of gas for power generation is expected to continue to grow. There are several publicly announced proposals for gas powered generation in the state.
Wind	South Australia has the greatest penetration of wind in Australia. The modelling for AEMO's 2010 National Transmission Development Plan (NTNDP[a]) shows further wind generation is possible.
Hydroelectricity	SA Water has a 1.9 MW mini-hydroelectric power plant on the Hope Valley Terminal Storage Tank, and is continuing to explore similar opportunities.[b]
Solar thermal	There are also several proposal to develop a commercial-scale solar thermal systems in the state.
Photovoltaic (PV)	The South Australian Government's feed-in tariff and the Australian Government's Small Scale Renewable Energy Target are expected to have a small (0.5%) impact on consumption.
Wave	South Australia is well-positioned to benefit from potential wave generation technologies, with coastline areas capable of generating in excess of 50 kW/m^2, and at least two companies are exploring opportunities in the state.
Geothermal	There are almost 30 organisations with a total of over 400 Geothermal Exploration Licenses in South Australia, with the 2010 NTNDP highlighting some opportunities for geothermal generation in South Australia.
Biomass	South Australia has several power stations being supplied from waste gas and there may be further opportunities to further utilise wood waste.

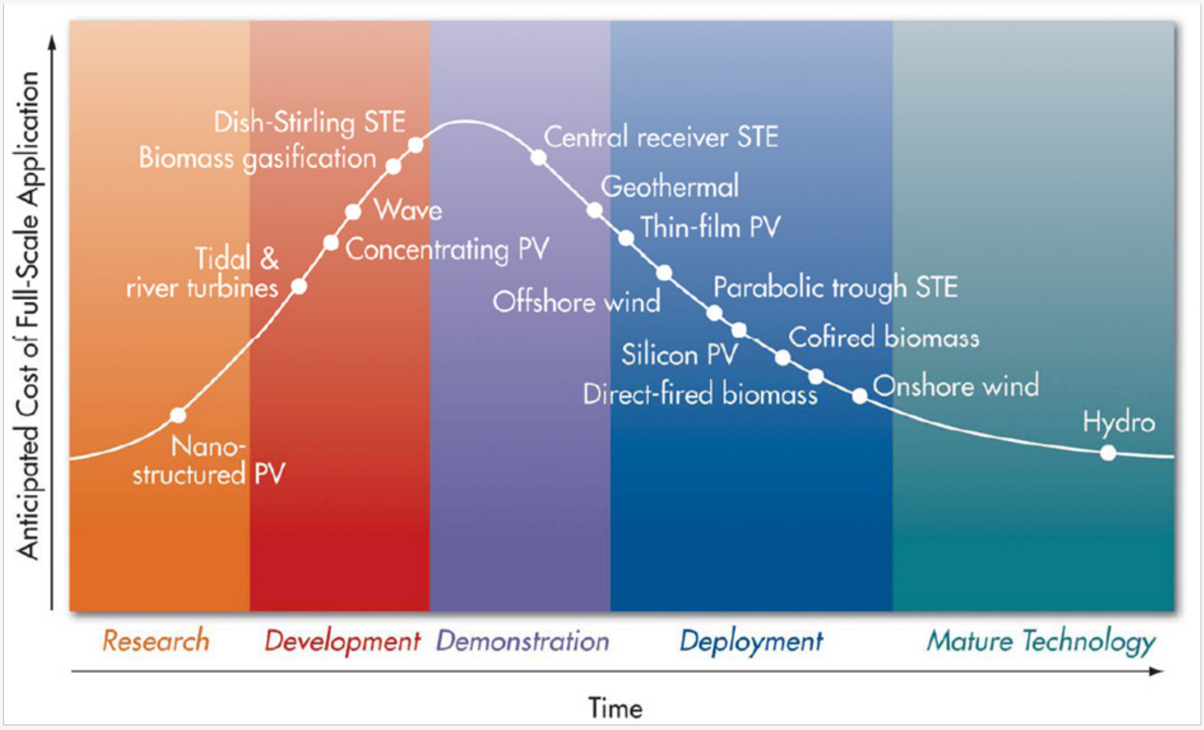
a. AEMO. National Transmission Network Development Plan 2010. December 2010.

b. SA Water/Government of South Australia. Mini-Hydro. http://www.sawater.com.au/SAWater/Environment/SaveWater/Innovation/Mini-Hydro.htm. Accessed 21 April 2011.

63 Unless otherwise referenced, the information in this appendix has been sourced from the following AEMO-commissioned reports:
- AEMO Cost Data Forecast for the NEM – Review of Cost and Efficiency Curves, 101010-00596 – REP/WBS 1Z0001A – 001, 31 Jan 2011 (WorleyParsons).
- Stage 1 Report: Key Energy Market Policies, A Report to the Australian Energy Market Operator, 23 March 2011 (KPMG).

Figure B-1 shows the varying levels of maturity of the renewable technologies considered.

Figure B-1 — Renewable technology development[64]



In general, many low emission technologies currently have high costs compared to traditional carbon emitting generation technologies. These costs are expected to decline as more low emission generation is deployed and technology development improves plant efficiency, although unfavourable movements in exchange rates can lead to increased costs. This is consistent across all the technologies considered.

B.1 Integrated gasification and combined cycle

Coal gasification is the conversion of coal into 'syngas' (carbon monoxide and hydrogen) by oxidising or burning it under high temperatures and pressures with oxygen and steam. The resulting gas stream is burnt in a conventional combined-cycle gas turbine. IGCC provides a mechanism for using a low cost fuel, such as coal, in a high-efficiency power generation cycle, such as a combined-cycle gas turbine. While the gasification process uses additional energy, overall cycle efficiency is still greater than a conventional pulverised coal power plant, and can also be combined with carbon capture and storage (CCS) technologies.

Availability

IGCC power generation technology is developing, with a limited number of manufacturers currently offering commercial plants. Australian experience of the technology is limited to a 10 MW pilot plant, built and operated by HRL Group at Morwell in Victoria's Latrobe Valley. HRL Group has introduced a drying stage in conjunction with the IGCC process to enable the use of the local brown coals. This is known as integrated drying and gasification combined cycle (IDGCC). Similar technology has been proposed for a full-scale 400 MW IGCC plant to be built by HRL Group, and for a project at Arckaringa in South Australia.

64 Electric Power Research Institute (EPRI). Australian Electricity Generation Technology Costs – Reference Case 2010. Prepared for: Australian Government Department of Resources, Energy and Tourism. February 2010.

The number of full-scale brown coal IGCC plants is limited, with most reference plants for gasification and IGCC technology using black coal. Experience with this technology on a commercial scale is limited, with only two commercial and one demonstration plant operating with black coal in the United States of America.

Future development

Full-scale IGCC plants are likely to require CCS in order to reduce emissions to within potential carbon reduction policy requirements. IDGCC and IGCC are both suitable for operation in combination with other efficiency and emission-reduction options. For both coal IGCC and IDGCC with CCS, improvements in the following areas are expected:

- Improved reliability and flexibility of the gasifier.
- Oxygen (O_2) separation (which can lead to reduced costs, and enhanced performance and efficiency of IGCC plants).
- Hydrogen (H_2) turbines (to increase plant economics) and fuel cells (aiming to enhance fuel utilisation and reduce CO2 emissions).
- Carbon capture.
- Super critical heat recovery steam generation cycles within the combined-cycle plant.
- Successful demonstration of similar technologies.

Significant research is ongoing, although this technology remains expensive.

Large-scale demonstration plants are expected to commence operating between 2017 and 2020.

B.2 Carbon capture and storage

The process of carbon capture produces a concentrated stream of carbon dioxide that can be compressed, transported, and stored. Depending on the power plant, carbon capture can take place through one of three processes:

- Pre-combustion is a process that removes carbon dioxide before it is burned as part of the gasification process. This process is also known as IGCC with CO_2 capture.
- Post-combustion is a process that removes the carbon dioxide from the flue gas after combustion by various means. This method is ideally applied to large point sources of combustion emissions.
- Oxyfuel or oxy-firing combustion is a process that burns the fuel in pure or enriched oxygen to create a flue gas composed primarily of carbon dioxide and water.

Post combustion capture and oxy-firing[65] are both suitable for retro-fitting to existing pulverised coal generation.

There are many storage possibilities for carbon dioxide. The likely location for storage is geological reservoirs including depleted oil and gas fields or deep unused saline formations. Formations such as depleted reservoirs securely trap and hold fluids such as oil and natural gas for millions of years. By injecting supercritical carbon dioxide deep underground (more than 800 metres) it is trapped by the overlying of caprock[66] within the storage formation.

Alternatively, deep porous rock formations saturated with unusable water (due to the salt or mineral content) are also suitable. These formations are widely dispersed throughout the world and meet all the necessary criteria for long-term storage. Injected carbon dioxide adds to fluid already trapped in the rocks, eventually dissolves in the saline water, and may combine chemically with the surrounding rocks. Deep saline formations represent most of the global geologic storage capacity for carbon dioxide and are likely to become the most widely used type of geologic storage.

[65] Oxy-firing can be considered a technology in its own right.
[66] Caprock is a non-permeable layer that can trap gas and other substances within a reservoir.

The plant and equipment operating to support the CCS process consume more energy than projects without CCS. This loss of efficiency is a reflection of the cost of reducing emissions, and will need to be recovered as part of the normal operation of the market.

Availability

A number of projects have been proposed in various Australian states over the last 10 years. One of the latest, the Callide A Power Station outside Biloela in Central Queensland, was committed to trialling clean coal technology (oxy-firing) by 2020. However the facility, as initially proposed, has recently been deemed 'not commercially viable.[63] It is now classified as a demonstration project, and is expected to be capturing carbon dioxide by the end of the year. [67]

Future development

Development of this technology is ongoing around the world. A promising potential new method to reduce costs for CCS involves the amine to chilled ammonia process[68], which may lead to an overall cost decrease for a number of technologies utilising CCS.[63] This process provides an alternative capture and carrier substrate that may reduce the overall power consumption needed to capture the carbon dioxide from the exhaust gas stream.

Other issues, unrelated to the development of the technology itself, include public concern about the impact of earthquakes, the potential production of acids from dissolving carbon dioxide in underground water, and criteria for screening storage sites close to the Great Artesian Basin.

B.3 Supercritical pulverised coal technology

The pulverised coal boiler-type dominates the electric power industry, producing approximately 50% of the world's electricity. Coal is crushed into a fine powder that is fed into a boiler and burned. The resulting heat generates steam that is expanded through a steam turbine to produce electricity. The pressure and temperature of the steam at the turbine inlet and just prior to entering the condenser determines the relative efficiency of the generation plant, and can be divided into supercritical (at least 24.8 MPa and 565 - 593 ºC), or subcritical (at or below 16.5 MPa and 538 ºC).

Supercritical units are between 2%-3% more efficient than subcritical units. The type of coal used also affects efficiency. Some brown coal deposits, such as those in the Latrobe Valley, have very high moisture content and require drying before combustion, reducing the overall cycle efficiency. Leigh Creek Coal and black coal from the eastern regions does not require drying prior to combustion.

Availability

There are approximately 300 supercritical units globally. There are plans to build a commercial-scale supercritical pulverised coal facility with a steam temperature of 700 ºC by 2016[63], with reported expectations of increased thermal efficiency available in commercial-scale plants by 2030, leading to lower carbon dioxide emissions.

Future development

Plants operating at higher turbine inlet pressures and temperatures are being investigated and are known as ultra-supercritical pulverised coal. The major technical issues with this technology are associated with new alloys and operating flexibility. New high-strength steel alloys for boilers and turbines are expensive, and plant operators are likely to have similar restrictions with respect to minimum stable output as conventional coal-fired sub-critical generating units.

[67] The Central Telegraph. Oxyfuel Project Moving forward. 6 April 2011. http://www.centraltelegraph.com.au/story/2011/04/06/oxyfuel-project-moving-forward/. Accessed 1 May 2011.

[68] For more information see Alstom. Carbon Capture and Storage. Available at: http://www.alstom.com/us/products-and-services/power/ccs/. Accessed 5 May 2011.

B.4 Open/closed cycle gas turbines (OCGT/CCGT)

A gas or combustion turbine is typically an axial flow rotary engine, with a combustion chamber located between an upstream compressor and a downstream turbine. A traditional open-cycle gas turbine (OCGT) compresses air in a gas compressor, then adding energy to the compressed air by combusting liquid or gaseous fuel in the combustor, producing power to drive the turbine rotor.

A combined-cycle gas turbine (CCGT) uses the exhaust heat from one or a number of OCGT units to generate steam in a relatively conventional boiler to drive a steam turbine. This use of waste" heat increases the output from the generator for the same amount of fuel, increasing the overall efficiency of the system.

In comparison with coal-fired generators, CCGT has shorter construction times, lower investment costs, and high service flexibility, but higher fuel costs.[69] The high efficiency of a CCGT can mean that for the combustion of the same amount of fuel, the emissions can be as low as half that of a conventional steam-cycle generator per kWh generated, and their production of non-greenhouse gas (GHG) emissions, such as sulphur oxides (SO_x), nitrogen oxides (NO_x), and particulate matter, are also relatively low.

CCGT units suitable for operation in Australia are already achieving efficiencies of up to 60%, although units of a suitable size for operation in South Australia are less efficient.

Availability

OCGT and CCGT generation is already commercially available and operating in South Australia, and can be designed to operate on almost all forms of liquid and gaseous fuels.

Future development

CCGT development and efficiency improvements are primarily focused on operating at higher firing temperatures and high-pressure ratios. The more efficient post-combustion capture and carbon dioxide compression technologies anticipated for supercritical pulverised coal technology can also be applied to CCGTs.

While older OCGT units may be relatively less efficient, most new OCGTs offer efficiencies between 35% and 42% at full load. Technology improvements are expected to deliver efficiencies as high as 45% by 2020.[69]

New CCGT units offer electrical efficiency of between 52% and 62%, and their efficiency is expected to reach 64% by 2020.[69]

Research into a number of OCGT/CCGT variants is ongoing, and includes using pure hydrogen and oxygen with zero carbon emissions, or oxy-firing with fuels like natural gas and other fossil fuels to facilitate CCS.

The thermal efficiency of a CCGT with post-combustion capture of carbon dioxide can be up to 10% lower than a unit without CCS. The efficiency penalty associated with the addition of CCS is expected to reduce, increasing the overall efficiency of CCGT with CCS by at least 8% by 2030.

Current natural gas price uncertainty makes it difficult to adopt robust strategies for CCGT development, and may result in a changing economic balance between gas and coal-fired generation.[69]

B.5 Wind

Wind power harnesses naturally occurring wind to drive wind turbine blades, which in turn drive a generating unit. Wind generation is one of the most mature renewable energy technologies currently available.

[69] Energy Technology Systems Analysis Program. Technology Brief E02 – April 2010. http://www.etsap.org/E-techDS/PDF/E02-gas_fired_power-GS-AD-gct.pdf. Accessed 21 April 2011.

Availability

South Australia has the greatest penetration of wind in Australia. The 2010 NTNDP modelling shows that further wind generation in South Australia is possible.[70] Australia has some of the world's best wind resources. The total operating wind generation capacity at the beginning of 2011 was 1,991 MW, of which almost 1,100 MW was in South Australia. The installed capacity of wind power has increased by an average of 30% per year over the past decade. Wind energy currently supplies approximately 3,000 GWh annually, which equates to approximately 20% of the state's energy consumption. This compares with NEM supplies of approximately 5,049 GWh or 2.5% of NEM generation.

Future development

Wind energy is expected to continue to be a key technology in response to higher renewable energy targets and the potential introduction of a price on carbon. Further growth in wind generation in the state will benefit from investment in transmission networks that can limit the carriage of high levels of wind energy.

For a detailed analysis of wind generation in South Australia, see Chapter 5, Section 5.4.

In 2010, AEMO and ElectraNet embarked on a joint feasibility study to examine issues related to augmenting the existing interconnector, and potentially developing a larger link to the eastern regions over diverse paths. This work was published on 4 February 2011.[71]

B.6 Hydroelectricity

Hydroelectric generation uses the power of pressurised, flowing water to spin a turbine connected to a generating unit. The amount of electricity generated depends on the height of the water above, and the volume flowing through, the turbine. Large hydroelectric power stations use water storage dams, which are often built for irrigation or drinking water, with the power station included to ensure maximum value is extracted from the water.[72]

Availability

Hydroelectricity delivers the majority of Australia's renewable energy. There are more than 100 hydroelectric power stations in Australia with a total installed capacity greater than 8 GW. However, South Australia has limited water resources and has a single 1.9 MW mini hydroelectricity plant operating from the Hope Valley Terminal Storage Tank.

Future development

Hydroelectricity is a mature technology. Over the past decades, no major breakthroughs have occurred in the basic machinery. Computer technology, however, has led to significant improvements in turbine blade optimisation and operating processes, such as computer monitoring, diagnostics, protection and control. Manufacturers and suppliers will need to invest significant resources in research and development to meet computing technology advancements and market competition[73] from other generation technologies in order to remain competitive.

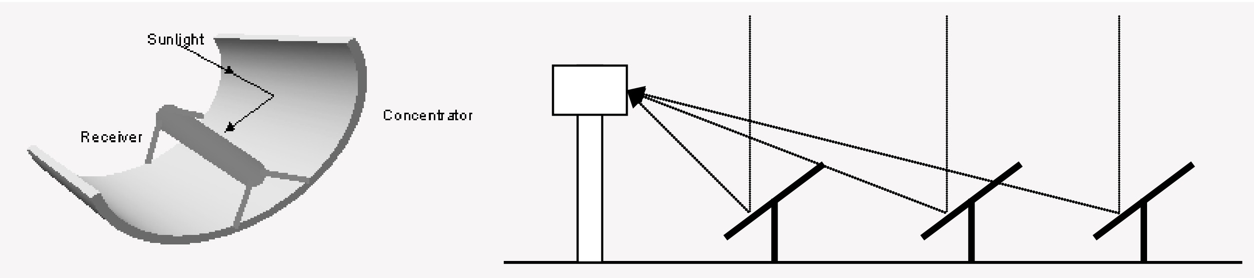
[70] AEMO. National Transmission Network Development Plan. www.aemo.com.au/planning/ntndp.html. Accessed 7 Jun 11.
[71] AEMO. South Australian Interconnector Feasibility Study. http://www.aemo.com.au/planning/saifs.html. Accessed 9 May 2011.
[72] Clean Energy Council fact sheets. http://www.cleanenergycouncil.org.au/cec/resourcecentre/factsheets.html. Accessed 21 April 2011.
[73] Energy Technology Systems Analysis Programme. IEA ETSAP – Technology Brief E12 – May 2010. http://www.etsap.org/E-techDS/PDF/E07-hydropower-GS-gct.pdf. Accessed 21 April 2011.

B.7 Solar thermal

Solar thermal generation technologies use the Sun's heat for the direct or indirect production of steam. There are two main types or solar thermal technology:

- Parabolic troughs (or dishes) concentrate reflected heat energy from the sun onto a focal point.
- Solar towers use a number of large flat sun-tracking mirrors (heliostats or linear Fresnel mirror systems) to focus heat onto a focal point, called the central receiver, usually mounted in a tower.

Figure B-2 — Parabolic and solar tower technology



Depending on the type and/or number of mirrored surfaces, solar thermal systems can generate temperatures in excess of 560 °C. The heat is harnessed by passing a working fluid, such as water, molten salt, or synthetic oil, through the focal point. The heat can be used to generate steam either directly (if the working fluid is water) or indirectly (by heating a working fluid that heats water in a heat exchanger), which is used in steam turbines to generate electricity. Some solar thermal technologies enable the storage of the heat energy before it is used to produce steam.

Availability

Currently, the most mature solar technology is the parabolic trough, which is approaching the commercialisation phase. While central receiving towers have been demonstrated, the technology and cost challenges associated with commercialisation are still being resolved.

Using molten salt as the heat transfer fluid (as opposed to synthetic oil), has the potential to obtain steam of 565 °C or more, without the cost or performance issues associated with using water as the heat transfer fluid. Significant engineering, operating, and maintenance issues arise, however, due to the high freezing temperature of molten salts, and research and development is ongoing. South Australia is one of the country's leading centres for solar thermal research and development.

Future development

It is expected that development and further refinement of these systems for power generation will continue to 2030. Without some sort of energy storage arrangement, a solar thermal plant is limited in its hours of operation. Significant research is ongoing into methods of storing the heat such that it can be used overnight or during periods of low solar radiation. To maintain direct production output levels, the size of the reflective area must be increased to allow additional energy from the larger area to be stored for later recovery.

B.8 Photovoltaic

Solar photovoltaic (PV) technologies convert sunlight directly into electricity using semiconductor materials that produce electric current when exposed to light. PV technology can be installed as a fixed flat plate on roofs, a large field with no moving parts, or mounted on tracking devices that constantly optimise the orientation of the panel to the sun's rays.

Availability

Australia has high levels of solar radiation, and significant subsidies and growing public interest in green power are driving rapid growth in domestic and commercial rooftop PV growth. Several States have some form of feed in tariff or incentive that has resulted in a significant increase in PV installation. South Australia has approximately 10% of the grid-connected solar photovoltaic capacity in the NEM. Approximately 72 MW of roof-top PV capacity has been installed in South Australia, and system costs have dropped significantly with competition from new manufacturers. It is anticipated that the current rush to install rooftop solar systems will diminish in the next financial year as government incentives diminish.[74]

Future developments

The cost of electricity from photovoltaic generators is expected to continue to decrease in the future. This is due to an expected reduction in solar panel costs and increased efficiency. Research has continued to develop new PV configurations, such as multi-junction concentrators, that promise to increase cell and module efficiency.

The PV industry is following two development paths involving high efficiency cells and thin-film technology. Some research in the area of thin film has lead to options such as photovoltaic paint for cars and houses. The conversion efficiency of the paint is low but its application is very simple.

B.9 Wave

Wave power generation is based on the extraction of energy from the movement of the sea in response to wind, tides, and other atmospheric drivers. Wave energy can be extracted from various locations and by different methodologies. One review[75] identified approximately 100 projects with various working principles at different levels of development.

Availability

The Energy Technology Systems Analysis Programme (ETSAP) estimates that approximately 2% of the world's 800,000 kilometres of coastline exceeds a power density of 30 kW/m, with a technical potential of approximately 500 GW based on a conversion efficiency of 40%. ETSAP also cites figures involving parts of South Australia's coastline (particularly those facing southwest), which have been assessed as having a power density of over 50 kW/m. If issues such as material corrosion and implications for fishing are addressed, ETSAP estimates that wave power could become commercial by around 2020.[76] The accuracy of these assessments is difficult to gauge, however, due to the immaturity of the technology.

The Clean Energy Council renewable database includes 16 wave energy projects across Australia at various stages of maturity.[63] Carnegie Wave Energy Limited is developing wave energy technology, including a trial of CETO[77] units in Western Australia. They also hold a licence to test wave resources on the limestone coast near Port MacDonnell in South Australia. Another company, Wave Rider, has proposed a pilot plant near Elliston, South Australia, which is scheduled for deployment in 2011.

Future development

Wave and tidal energy conversion technology is still in its infancy. The installed capacity of ocean energy devices supplying to national grids worldwide is less than 10 MW as of 2010. [63] There are many challenges that must be overcome for wave and tidal energy to be both feasible and economical enough to compete with or complement more mature renewable sources, such as wind energy. Prices for electricity from wave and tidal generation are difficult to calculate due to the limited cost information and operational experience. [63]

[74] There was a bill introduced to Parliament on 6 April 2011 proposing a cut-off date of 1 October 2011 for SA's feed-in tariff scheme.

[75] António F.de O. Falcão. "The Development of Wave Energy Utilisation". OES-IA Annual Report 2008. www.iea-oceans.org. Cited at: http://www.etsap.org/E-techDS/PDF/E08-Ocean%20Energy_GSgct_Ana_LCPL_rev30Nov2010.pdf. Accessed 21 April 2011.

[76] Energy Technology Systems Analysis Programme. IEA ETSAP - Technology Brief E13, Marine energy. November 2010. http://www.etsap.org/E-techDS/PDF/E08-Ocean%20Energy_GSgct_Ana_LCPL_rev30Nov2010.pdf. Accessed 21 April 2011.

[77] Carnegie. What is CETO. http://www.carnegiecorp.com.au/index.php?url=/ceto/what-is-ceto. Accessed 21 April 2011.

It is expected that[63]:

- commercial development of wave power devices will not commence until 2015
- rates of development will be slow, and
- large-scale development will take up to 10 years following commercial demonstration.

B.10 Geothermal

Geothermal energy is derived from the natural heat found within the earth. Approximately 10,000 MW of global electricity generation capacity is based on conventional steam from geothermal and hot water hydrothermal generation.

Australia, however, does not have the wet, high-temperature geothermal environments found in volcanically-active countries such as New Zealand. Australia's hydrothermal systems are neither hot enough nor under sufficient pressure to produce large amounts of steam (such as that used in dry steam, and flash geothermal systems). Potential Australian developers seek areas with a high heat gradient, which can be generated from the radioactive decay of naturally occurring potassium, thorium, and uranium isotopes in the Earth's crust. To exploit most Australian geothermal resources a dual fluid cycle power generation system is required. This system passes geothermally heated water or hot geoliquid through a heat exchanger, where it transfers heat to a secondary liquid (the working fluid) with a much lower boiling point than water. The working fluid boils to a vapour and is expanded through a turbine connected to a generating unit, which produces electricity.

Systems with potential in Australia include the following:

- Hot rock (HR) systems, which are harnessed through the circulation of water via injection and production wells. An artificial geothermal reservoir can be formed connecting the two wells by fracturing or stimulating the rock mass at the base. This is known as resource stimulation, and can be done by injecting water into a well under high pressure. The force of the water in the well causes hydraulic fracture of the rock mass at the base of the well, creating a reservoir. Once the system is in place, water is injected into hot granite rock underground. Heat extracted from the rock is transferred to a secondary or working fluid and is then recirculated and pumped back down the injection well.
- Hot sedimentary aquifers (HSA) involve reservoirs in which rain water that has been absorbed into the ground is heated by contact with hot rocks. The temperature of these rocks typically increases with depth. The water collects in porous rocks between two impermeable sedimentary layers, creating an aquifer from which hot fluid can be extracted by a drilling process. The key to HSA research and development is to find shallow systems to reduce development costs and allow the use of proven hydrothermal systems and supporting technology.

Enhanced Geothermal Systems such as Hot Dry Rock and Hot Fractured Rock represent emerging technologies where the heat stored underground is captured using mining technology to circulate water through a natural or stimulated underground heat exchanger, and conventional generation techniques to generate power from the hot fluid when it returns to the surface. Enhanced Geothermal Systems currently do not figure significantly in the installed geothermal capacity worldwide. Analysis, research and development being performed in Australia is part of a significant worldwide push to utilise the vast amounts of the earth's stored thermal energy.

The development of a geothermal site requires the consideration and evaluation of a number of factors, such as the site geography, geology, reservoir size, geothermal temperature, and plant type. The cost is affected not only by the size and design of the power plant, but also the geothermal resource temperature and pressure, steam, impurity and salt content, and well depth.

Availability

The only working geothermal power station in Australia is in Birdsville, Queensland, and is rated to 120 kW.[72] Australia has large volumes heat producing granites at accessible depths of 3-5 kilometres from the surface.[63]

These granites can reach 300 °C, representing vast sources of clean energy that can potentially be tapped by hot fracture rock geothermal technology.[78] Attempts have been made to commercialise the hot rocks of the Cooper Basin in South Australia and Queensland. The ETSAP program predicts that Australia will be generating geothermal energy commercially from 2015 onwards.[79]

A number of Australian geothermal companies have commenced drilling of exploration and production wells. Projects of this type in South Australia include the following:

- Geodynamics, operating north west of Moomba in South Australia have now drilled five deep wells to depths approaching, or greater than, 4,000 m. Geodynamics have used three deep wells at Habanero in the Cooper basin to demonstrate proof of concept of hot fractured rock and linkage between wells. Geodynamics plan to have a 1 MW demonstration plant operating by the second quarter of 2012, with subsequent commercial plans for a 500 MW expansion by 2020.[80]
- A Petratherm pilot scheme at Paralana to build a 7.5 MW geothermal power plant, expanding to 30 MW. To date, Petratherm have completed drilling one injector well, called Paralana 2. In May 2011, the company expects to commence fracture stimulation of the well.
- Panax finished drilling its Salamander-1 well at their Penola Project on 16 March 2010. Well testing indicated that complications of the well restricted communication between the intersected reservoir and the open hole section of the well bore. Panax has engaged reservoir engineers to examine this issue.

Future development

Geothermal power is potentially a renewable base-load technology. NTNDP market simulations found an average of nine new geothermal or wind power stations are possible in northern South Australia.

HR is not yet a commercial technology. The same plant and drilling technologies can be used as hydrothermal plants (which are considered commercial), but cost, injection and recovery of the working fluid, and depth remain significant issues. Operational uncertainties involving the resistance of the reservoir to flow, thermal drawdown over time, and water loss have also made commercial development uncertain. Lower-cost resource assessment and drilling technologies are required to make HR systems commercially viable.

HSA is also not yet commercially proven, but is expected to be more easily developed than some other near-term geothermal projects. HSA uses a conventional low-temperature dual-fluid cycle, involves shallower drilling, and does not require resource stimulation, and therefore it is considered less risky than HR. Several potential sedimentary basins have been identified in Australia, which may have lower exploration, drilling, and reservoir risks.

Advancement of geothermal generation other than HSA in Australia will depend on the development of rock-fracturing technologies to enable high production rates from abundant HR resources.

B.11 Biomass

Biomass technology uses fuels produced from plant and animal matter. These fuels have the potential to enable generating units to produce power on a continuous basis, since the fuels may be stored. There are a number of potential fuels for biomass generation, including bagasse, wood waste, crop oils, sewage, agribusiness residues, landfill gas, and various other waste products.

78 Commonwealth Science Industry Research Organisation (CSIRO), Geothermal Energy: Hot Fractured Rocks. http://www.csiro.au/science/Geothermal-energy.html. Accessed 21 April 2011.

79 Energy Technology Systems Analysis Programme, Geothermal Heat and Power. IEA ETSAP – Technology Brief E07 – May 2010. http://www.etsap.org/E-techDS/PDF/E06-geoth_energy-GS-gct.pdf. Accessed 21 April 2011.

80 Geodynamics. Project Update – Forward work program Innamincka Joint Venture. Media Release. April 13 2010. http://www.geodynamics.com.au/IRM/Company/ShowPage.aspx?CPID=2161&EID=88992574. Accessed 2 May 2011.

Generally, biomass fuel pricing is highly sensitive to the locale, and the competitive pressures of local and regional economies. Some of the current technologies that are commercially available, or commercially offered, include combustion or gasification to produce heat, steam, or gases for generation, conversion to biofuels, such as bio-diesel or ethanol for transport or energy production, and landfill extraction or anaerobic digestion of sewage or animal waste along with gas generation technology. In addition, potential technologies include pyrolysis and compacted biofuel.[81]

Availability

The biomass generation sector's installed capacity in Australia is 767 MW.[72] Biomass firing of bagasse occurs in Northern New South Wales, Northern Queensland, and many other parts of the world.[63] Landfill gas fired power generation is also a commercial technology, but is highly dependent on site conditions such as the ease of recovery of landfill gas. Waste to energy power generation technology is highly dependent on the composition of the waste used as fuel.

In South Australia, there are several landfill gas operations generating electricity. There have also been proposals to develop or redevelop power generating facilities using wood waste, which is primarily used to provide heat for processing plant operations.

Future development

There is potential for biomass to deliver 11,000 GWh of electricity to Australia annually to 2020.[72] Biomass is not a new form of power generation and has been commercially available for many decades. Improvements in biomass technology will come from improvements in fuel gathering and fuel preparation technologies. Fresh biomass has serious disadvantages as a fuel compared with fossil fuels due to its relatively high moisture content, low density, modest thermal content, and form, which is rarely homogenous or free flowing, making collection and automatic feeding difficult.

The purpose of preparation techniques is to minimise the effect of these issues.

[81] Clean Energy Council. Australian Bioenergy Roadmap: Setting the direction for biomass in stationary energy to 2020 and beyond. http://www.cleanenergycouncil.org.au/dms/cec/industrydevelopment/bioenergy/01-Australian-Bioenergy-Roadmap/01%20Australian%20Bioenergy%20Roadmap.pdf. Accessed 21 April 2011.

[This page is left blank intentionally]

GLOSSARY

Term	Meaning
2P	Proved plus probably gas reserves. The best estimate of commercially recoverable resources. Often used as the basis for reports to share markets, gas contracts, and project justification economics.
Agreed maximum demand	The measured demand during the maximum demand period for a connection point or a group of connection points.
Capacity factor	A measure of how consistently a generator is producing power (the ratio of the actual output of a power plant over a period of time and its potential output if it had operated at full nameplate capacity the entire time).
Carbon dioxide equivalent (CO2-e)	The mix of greenhouse gases including carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O) perfluorocarbons (PFC), hydrofluorocarbons (HFC), and sulphur hexafluoride (SF_6).
Cooling degree days	A measurement designed to reflect the amount for energy required to cool a home or a business. The number of degrees that a day's average temperature is above a base temperature (18.5 ^{o}C), the temperature above which buildings need to be cooled.
Demand side management	The act of administering electricity demand-side participants (possibly through a demand-side response aggregator).
Demand-side participation	The situation where customers vary their electricity consumption in response to a change in market conditions, such as the spot price.
Distribution network	A network which is not a transmission network.
Electricity Supply Industry Planning Council of South Australia	Former South Australian electricity planning organisation. Now AEMO.
Exempted generator	A generator exempted from the requirement to register in accordance with Clause 2.2.1 of the NER, and in accordance with the Australian Energy Market Operator's Generator Registration Guide.
Generation	The production of electrical power by converting another form of energy in a generating unit.
Generator	A person who engages in the activity of owning, controlling, or operating a generating system that is connected to, or who otherwise supplies electricity to, a transmission or distribution system and who is registered by AEMO as a generator under Chapter 2 of the NER and, for the purposes of chapter 5 of the NER, the term includes a person who is required to, or intends to register in that capacity.
Heating degree days	A measurement designed to reflect the amount for energy required to heat a home or a business. The number of degrees that a day's average temperature is below a base temperature (e.g. 18.5 ^{o}C), the temperature below which buildings need to be heated.
Interconnector	A transmission line or group of transmission lines that connects the transmission networks in adjacent regions.
Jurisdiction	An area over which legal authority extends – Australian State, Territory or Commonwealth.
Maximum Demand	The highest amount of electrical power delivered, or forecast to be delivered, over a defined period (day, week, month, season or year) either at a connection point, or simultaneously at a defined set of connection points.
Nameplate capacity	The maximum continuous output or consumption in MW of an item of equipment as specified by the manufacturer, or as subsequently modified.
National Electricity Market	The wholesale market for electricity supply in the Australian Capital Territory and the states of Queensland, New South Wales, Victoria, Tasmania and South Australia.

Term	Meaning
National Transmission Network Development Plan	An annual report to be produced by the Australian Energy Market Operator (AEMO) that replaces the existing National Transmission Statement (NTS) from December 2010. Having a 20-year outlook, the NTNDP will identify transmission and generation development opportunities for a range of market development scenarios, consistent with addressing reliability needs and maximising net market benefits, while appropriately considering non-network options.
Non-scheduled generation	Refers to generating systems with an aggregate nameplate capacity of less than 30 MW and equal to or greater than 5 MW.
Price elasticity of demand	Measures the responsiveness of the energy demanded due to a change in price. It equals the percentage change of the quantity demanded divided by the percentage change in price.
Probability of Exceedence	Refers to the probability that a forecast electricity maximum demand figure will be exceeded. For example, a forecast 10% POE maximum demand figure will, on average, be exceeded only 1 year in every 10.
Probable reserves	Estimated quantities of gas that have a reasonable probability of being produced under existing economic operating conditions. ‘Proved and probable’ reserves added together to make up 2P reserves.
Proved reserves	Estimated quantities of gas that are reasonably certain to be recoverable in the future under existing economic and operating conditions. Also known an 1P reserves.
Retailer	Those selling the bundled product of energy services to the customer.
Scheduled generation	Refers to any generating system with an aggregate nameplate capacity of 30 MW or more, unless it is classified as semi-scheduled, or the Australian Energy Market Operator (AEMO) is permitted to classify it as non-scheduled.
Semi-scheduled generation	Refers to any generating system with intermittent output (such as wind or run-of-river hydro) with an aggregate nameplate capacity of 30 MW or more. A semi-scheduled classification gives AEMO the power to limit generation output that may exceed network capabilities, but reduces the participating generator’s requirement to provide dispatch information. The supply-demand outlook de-rates the installed capacities of semi-scheduled wind generators to account for firm contributions at the time of the maximum demand.
Time weighted average price	The simple average of the (wholesale market) price over a specified period
Transmission (gas)	Long haul transportation of gas via high pressure pipelines.
Transmission network (electricity)	A network within any participating jurisdiction operating at nominal voltages of 220 kV and above, plus any part of a network operating at nominal voltages between: • 66 kV and 220 kV that operates in parallel to and provides support to the higher voltage transmission network, and • 66 kV and 220 kV that is not referred to in paragraph (a) but is deemed by the Australian Energy Regulator (AER) to be part of the transmission network.
Transmission network service provider	A person (usually an organisation) who engages in the activity of owning, controlling or operating a transmission system.
Transmission system (electricity)	A transmission network, together with the connection assets associated with the transmission network, which is connected to another transmission or distribution system.
Unserved energy	The amount of energy that cannot be supplied because there is insufficient generation capacity, demand-side participation (DSP), or network capability to meet demand. Under the provisions of the Reliability Standard, each region’s annual USE can be no more than 0.002% of its annual energy consumption. Compliance is assessed by comparing the 10-year moving average annual USE for each region with the Reliability Standard.
Volume weighted average price	The total value of the energy traded in the market divided by the total quantity of energy produced, better representing the average price received by the market participant.