2012

ELECTRICITY STATEMENT OF OPPORTUNITIES

For the National Electricity Market

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EXECUTIVE SUMMARY

Reduced growth in energy use is expected to defer new generation or demand-side investment for at least four years compared to the forecasts in the 2011 Electricity Statement of Opportunities (ESOO).

Significantly reduced annual energy and maximum demand projections are the main drivers for the later Low Reserve Condition (LRC) points. AEMO's latest annual energy projection for the National Electricity Market (NEM) predicts average annual growth of 1.7 per cent, considerably lower than the 2.3 per cent projected in 2011.

This reduction in growth is attributed to changes in the economic outlook, including a short-term moderation in gross domestic product (GDP), reduced manufacturing consumption and consumer response to rising electricity prices and energy efficiency measures.

The 2012 AEMO ESOO uses independent electricity forecasts and the most up-to-date information on generation capacity to analyse important changes taking place across Australia's energy landscape.

Table 1 — Supply-demand outlook update (medium scenario)

Region	2012 ESOO		2011 ESOO	
	LRC point	Reserve deficit (megawatts)	LRC point	Reserve deficit (megawatts)
Queensland	2020–21	79	2013–14	341
New South Wales	>2021–22	-	2018–19	190
Victoria	2018–19	115	2014–15	96
South Australia	2019–20	24	2014–15	46
Tasmania (winter)	>2022	-	>2021	-

Key observations for the 2012 Electricity Statement of Opportunities:

The current outlook (see Table 1) predicts reserve deficits in:

- Victoria in 2018–19, which defers the LRC point by four years.
- South Australia in 2019–20, which defers the LRC point by five years.
- Queensland in 2020–21, which defers the LRC point by seven years.
- The outlook predicts no reserve deficits in New South Wales or Tasmania prior to 2021–22.

Projections of maximum demand have been reduced for all regions:

- Queensland is the fastest-growing region under a medium economic growth scenario, with an average annual projected maximum demand growth rate of 2.5 per cent compared to 4.2 per cent in 2011.
- All other regions are projected to grow at between 1.0 and 1.6 per cent per year.

Generation capacity updates for 2012 include new plant that has come on line since the 2011 ESOO was released:

- The Oaklands Hill Wind Farm (67 MW) in Victoria and Hallett 5 Wind Farm (53 MW) in South Australia.
- The Mortlake Stage 1 open-cycle gas turbine plant (566 MW) in Victoria.
- The Eraring Power Station upgrade (60 MW) in New South Wales.

Five additional generation projects are now committed:

- The Macarthur Wind Farm (420 MW) and Mortons Lane Wind Farm (20 MW) in Victoria, and Musselroe Wind Farm (168 MW) in Tasmania.
- The Qenos Cogeneration Facility (21 MW) in Victoria.
- The new upgrade of Eraring Power Station in New South Wales by a further 60 MW.

Three power stations are planned for retirement, and a further three have issued availability updates, with no real impact on the short-term supply adequacy:

- The Mackay Gas Turbine (34 MW) and Swanbank B Power Station Unit 3 (125 MW) in Queensland.
- The Munmorah Power Station (600 MW) in New South Wales.
- The Morwell Power Station Unit 5 (75 MW) in Victoria is assumed to be unavailable in the outlook for both summer and winter periods.
- The Playford B Power Station (240 MW) in South Australia is assumed to be unavailable in the outlook for both summer and winter periods, and the Northern Power Station (530 MW) in South Australia is assumed to be unavailable from 1 April to 30 September in 2013 and 2014.

Investment trends

Current investment interest is focused on renewable and peaking generation (see Figure 1), with publicly announced proposals involving over 13,000 MW of wind generation and over 11,000 MW of open-cycle gas turbine (OCGT) generation.

Wind generation makes up the majority of new committed projects, with investments being primarily driven by the Large-scale Renewable Energy Target (LRET) and GreenPower schemes. However, publicly announced proposals for wind generation have decreased by around 2,200 MW since the 2011 ESOO, with 14 of the 18 previously publicly announced wind farm proposals that are now unlikely to proceed located in Victoria.

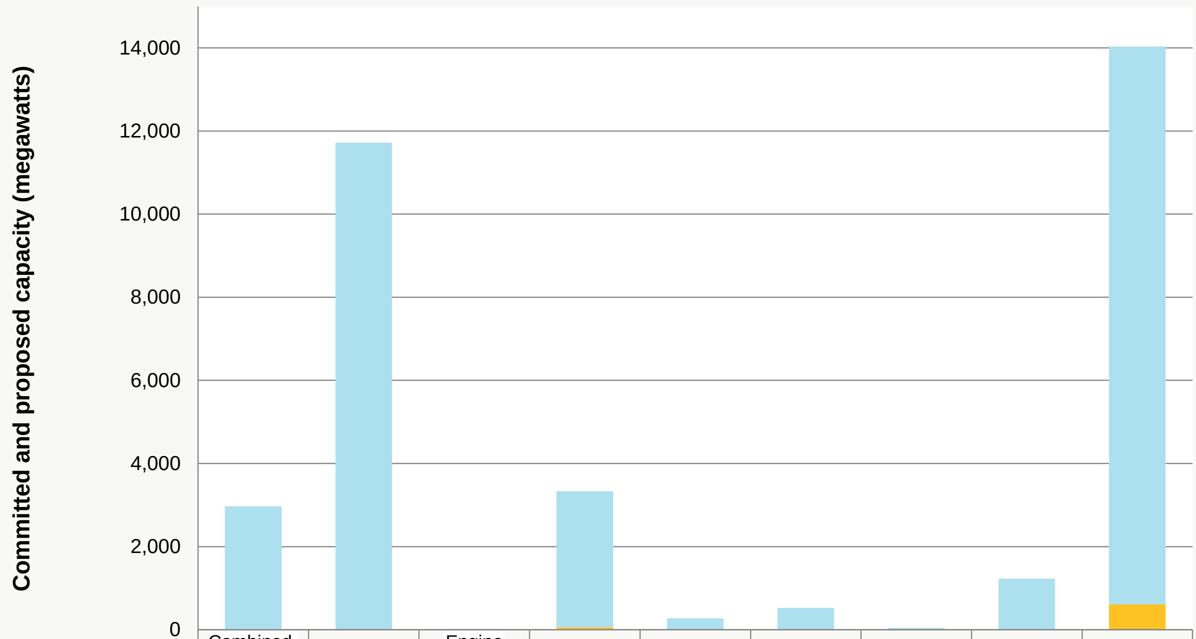
AEMO expects increased interest in wind generation investment around 2016, with a potential shortfall in capacity to meet the LRET emerging in the second half of the decade.

Future implications

While the signals for base load generation investment are muted, there is potential for generation or demand-side investment before 2018–19, with ongoing changes affecting Australia's energy landscape.

The Commonwealth Government's Contracts for Closure (CFC) Program – which aims to retire up to 2,000 MW of high CO_2-emitting generating units by 2020 – has the potential to alter the LRC point projections and bring forward the need for generation or demand-side investment. The introduction of the carbon price in July 2012 will contribute to changes to the competitiveness of existing generators, potentially creating opportunities for new baseload generation.

Figure 1 — Current commitment status of public generation developments in the NEM



	Combined-cycle gas turbine	Open-cycle gas turbine	Engine (gas-fuelled)	Black coal	Biomass	Geothermal	Hydro	Solar	Wind
Publicly announced	2,950	11,720	17	3,270	273	525	40	1,228	13,427
Advanced							3		
Committed	21			60					608

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CHAPTER 1 - INTRODUCTION

1.1 Introduction

The Electricity Statement of Opportunities (ESOO) supports decision making within the National Electricity Market (NEM) by providing an analysis of electricity supply and demand over a 10-year outlook period. It also includes historical information about the changing electricity generation mix and trends in electricity demand, which is combined with the most up-to-date information from energy market participants and AEMO's latest electricity demand forecasting, to assess supply adequacy for the next 10 years.

While summarising the investment environment for each NEM region[1], including the supply-demand outlook and current generation investment interest, the ESOO also highlights NEM-wide generation and demand-side investment opportunities by analysing the key factors influencing this type of investment in 2012.

Key factors relevant to 2012 include reduced electricity demand growth and renewable energy investment to meet the national Renewable Energy Target (RET) scheme.

1.1.1 Changes to the ESOO since 2011

The Australian Energy Market Operator (AEMO) is changing the way it presents energy market information, to provide stakeholders with more timely and focused responses to the changing industry environment.

Moving away from the print publication of a small number of larger reports, AEMO is electronically publishing a series of smaller reports that focus on specific issues, and are supported by supplementary reports and data files (for a list of these supplementary reports, see Section 1.6).

Given this new approach, several key changes have been made to the ESOO since 2011, involving the separate publication of information covering a number of areas:

- Information about the NEM-wide and regional electricity demand forecasting and the economic outlook (as part of the National Electricity Forecasting Project), with the 2012 ESOO now incorporating high-level summaries only.
- Historical market information.
- Generation information, with the 2012 ESOO presenting a summary of generation capacity and investment at a NEM-wide level (see Chapter 2, Section 2.4), and for each region (see Chapter 3).
- Fuel supply information, with the 2012 ESOO presenting a summary of electricity generation capacity and output by fuel type. AEMO's Gas Reserve Update provides an analysis of current gas reserves and resources.[2] The Bureau of Resource and Energy Economics also publishes a detailed overview of Australia's energy resources in its annual Energy in Australia report.[3]
- Supporting and other background information, which is now available from AEMO's website, about the NEM's structure, rules and governance, to assist participants and investors that are new to the NEM (for more information, see Section 1.6).

These changes have resulted in a significantly abridged ESOO that aims to be more concise and accessible while still providing important information about the NEM's investment environment.

[1] The regions of the NEM are Queensland, New South Wales (including the Australian Capital Territory), Victoria, South Australia and Tasmania.
[2] AEMO. Available http://www.aemo.com.au/en/Electricity/Planning/Gas-Statement-of-Opportunities/Gas-Reserve-Update. Viewed 29 June 2012.
[3] BREE. Available http://www.bree.gov.au/documents/publications/energy/energy-in-australia-2012.pdf. Viewed 10 July 2012.

1.2 The ESOO in the energy planning context

The publication of the ESOO plays a key part in AEMO's energy planning role, by providing independent information about the NEM and up-to-date energy industry analysis. Through its suite of national planning documents, AEMO also delivers strategic gas and electricity transmission planning advice to guide long-term investment in network infrastructure and resource management. This includes the National Transmission Network Development Plan (NTNDP), which considers how the NEM transmission network may develop in the long term, and the Gas Statement of Opportunities (GSOO), which investigates supply-side reliability and gas resource information for the gas industry in Eastern and South Eastern Australia.

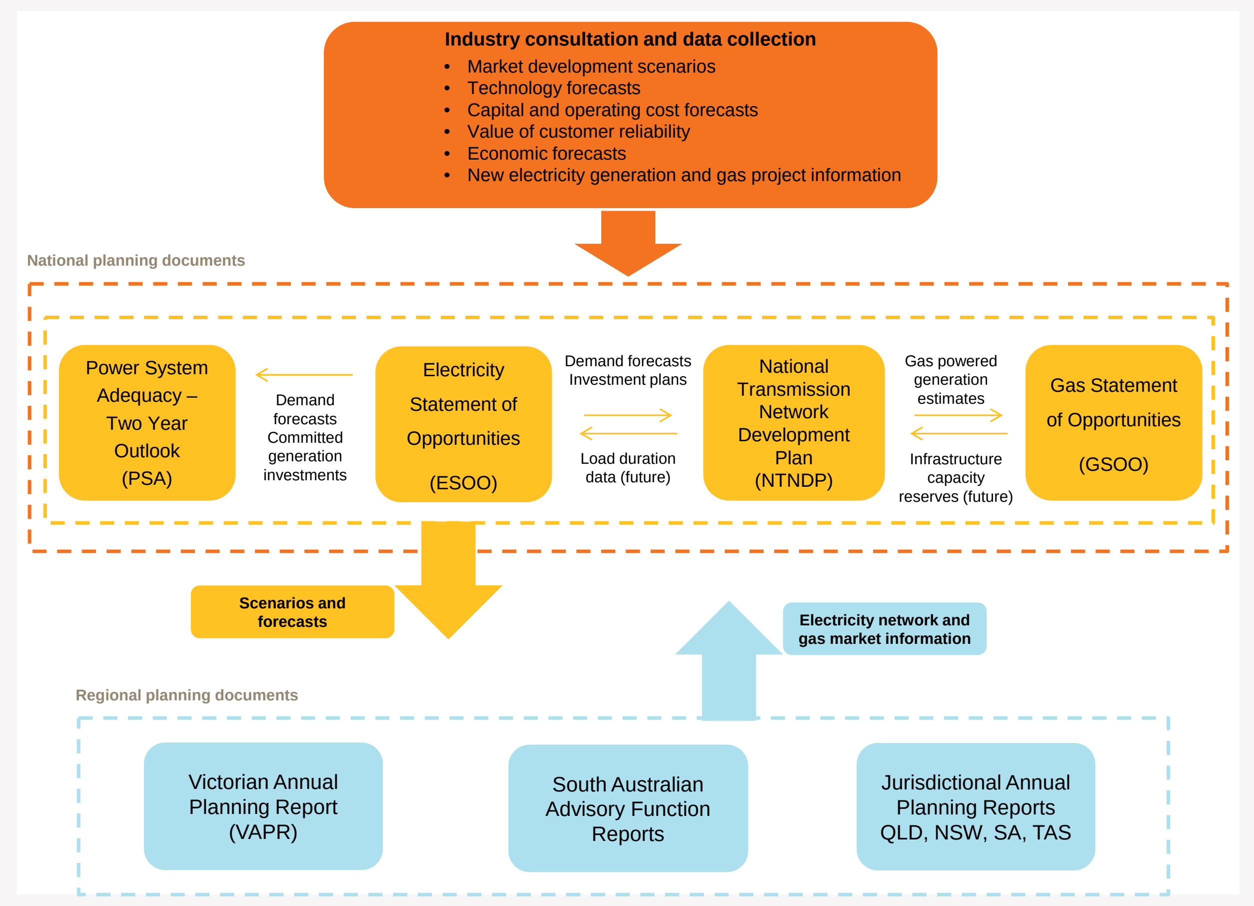
The ESOO highlights opportunities for new generation and demand-side investments based on projected supply shortfalls. Potential opportunities also exist for demand-side and generation investment to provide network services or to defer the need for network augmentations in the NEM. These network-driven opportunities are not analysed or presented in the ESOO. The NTNDP and electricity annual planning reports (APRs)[4], which focus on electricity transmission planning in each region of the NEM, provide information about network development and limitations that may lead to investment opportunities of this type.

AEMO also publishes a range of reports as part of its South Australian Advisory Functions, which address the current state and future development of South Australian electricity supplies, and complement the South Australian JPB's APR.

Figure 1-1 shows how the ESOO links with other energy planning reports.

[4] Published by AEMO and the jurisdictional planning bodies (JPBs) for New South Wales, Queensland, South Australia and Tasmania.

Figure 1-1 — Energy planning reports and the ESOO



1.2.1 NEM power system reliability assessments

AEMO assesses power system reliability through outlooks provided by the ESOO, the Power System Adequacy (PSA) – Two-Year Outlook, the Energy Adequacy Assessment Projection (EAAP), and the Medium-term Projected Assessment of System Adequacy (MT PASA). These publications explore system adequacy from differing perspectives and cover overlapping timeframes to provide a continuous indication of future power system reliability.

The Power System Adequacy – Two-Year Outlook

The annual PSA document supplements the ESOO by investigating operational issues over the next two years. This includes an analysis of any operational issues that may present a need for investment or action within the power system in the short term. System adequacy is measured against several key indicators including capacity reserve (the size of reserve margin), energy adequacy, frequency control, voltage control, post contingency control, and interconnector capability.

The Energy Adequacy Assessment Projection

The 2012 ESOO supply-demand outlook applies generation capacity advice provided by NEM generators, but does not specifically account for possible future energy limitations or short-term scheduled maintenance. Accounting for energy limitations becomes particularly important when determining the likely near-term impacts of drought, or when assessing the reliability of regions with significant hydroelectric generation.

AEMO assesses the impact of energy limitations through quarterly EAAP studies, providing a 2-year outlook quantifying the impact of energy constraints under multiple scenarios. The EAAP results are published quarterly on the AEMO website.

MT PASA and the supply-demand outlook

The supply-demand outlook and MT PASA both provide capacity adequacy assessments and consider similar input information. The supply-demand outlook provides an annual assessment over 10 years, while MT PASA provides a daily assessment over two years. This shorter time-frame enables MT PASA to consider more detailed system information available in the short term, including scheduled generating unit maintenance patterns.

MT PASA is used operationally to inform the market when there is a high likelihood of experiencing a low reserve condition that may require AEMO to intervene through the Reliability and Emergency Reserve Trader (RERT) process. In contrast, the supply-demand outlook is intended to provide participants and other interested parties with information about the timing and magnitude of the additional long-term investment required to maintain power system reliability.

Table 1-1 compares MT PASA and the supply-demand outlook.

Table 1-1 — MT PASA and supply-demand outlook comparison

	MT PASA	ESOO supply-demand outlook
Outlook	Two years.	Ten years.
Resolution	Daily.	Yearly.
Updated	Weekly.	Yearly.
Inputs		
Demand	Projected daily 10% probability of exceedence (POE) scheduled and semi-scheduled maximum demand, less committed demand-side participation (DSP).	Projected seasonal 10% POE scheduled and semi-scheduled maximum demand, less committed DSP.
Generation	Maintenance outages and short-term variations considered.	Advised summer and winter capacity. Long-term variations considered.
Wind generation	Uses 90% POE wind generation forecasts (Australian Wind Energy Forecasting System).	Calculates wind farm available capacity according to peak contribution factors.
Energy capacity	Weekly energy limitations submitted by generators are modelled.	Energy limitations are not modelled, except where stated as summer or winter capacity reductions.
Minimum Reserve Levels (MRLs)[a]	MRLs are applied to assess adequacy.	MRLs are applied to assess adequacy.
Network	System-normal operating considerations assumed. Existing transmission capabilities only.	System-normal operating considerations assumed. Existing and committed network.
Outputs		
Determine	Reserve levels at daily peak demand, and low reserve condition (LRC) points.	Reserve levels at summer or winter maximum demand, and LRC points.
Indicate	Opportunities for market response (2 years).	Opportunities for market response (10 years).
AEMO action	Possible intervention through the RERT process.	No action. Market information purposes only.

a. The MRLs represent a safety margin of installed capacity. For more information, see Chapter 2, Section 2.1.3.

Future assessments of supply adequacy

Assessing supply adequacy for the purposes of producing the ESOO requires a comparison of available capacity, demand-side participation, regional demand and network limitations against a set of pre-calculated reserve requirements. These reserve requirements are produced using a complex set of market simulations, and need regular review to ensure they remain appropriate as the power system evolves.

Supply adequacy results are particularly sensitive to aspects of the power system that change over time, such as demand diversity, the location and reliability of installed generation capacity, and significant transmission network augmentations.

AEMO is currently reviewing the methodology used to both calculate reserve requirements and assess supply adequacy. This review aims to identify accuracy and efficiency gains that may be possible by moving away from pre-calculated values, and instead integrating the reserve requirement calculations within the supply adequacy assessment itself. AEMO intends to consult with stakeholders on the outcomes of this review throughout 2012–13.

1.3 The Contract for Closure Program and national RET scheme

The CFC Program

The CFC Program is part of the Australian Government's Clean Energy Future package, designed to deliver the closure of approximately 2,000 MW of high carbon dioxide-equivalent emissions intensity, coal-fired generation capacity by 2020. Generation that progressed to the final round of negotiations in 2012 is located in Victoria, Queensland and South Australia.

The CFC Program has the potential to advance the timing of new investments in base load and peaking generation in the NEM. At the time of publication, however, there was insufficient information about plant closures to enable them to be modelled in the supply-demand outlook. AEMO will continue to monitor the progress of the CFC Program and release new information and results as appropriate.

The national RET scheme

The national RET scheme, which commenced in January 2010, aims to meet a renewable energy target of 20% by 2020.[5] Like its predecessor, the Mandatory Renewable Energy Target (MRET), the national RET scheme requires electricity retailers to source a proportion of their electricity from renewable energy sources.

The national RET scheme was implemented through Renewable Energy Certificates (RECs). Eligible renewable energy sources create RECs in proportion to their energy output, which can be traded, banked, or sold to retailers that must surrender an amount of RECs towards meeting the national target, in proportion to their share of national energy demand.

In January 2011, the scheme was restructured into two parts[6]:

- The Small-scale Renewable Energy Scheme (SRES) is available only to small-scale technologies (such as solar water heating), and is being implemented via Small-scale Technology Certificates (STCs).
- The Large-scale Renewable Energy Target (LRET) is being implemented via Large Generation Certificates (LGCs).

Certificates issued prior to 1 January 2011 are referred to as RECs, and certificates issued after this date are referred to as STCs or LGCs.

[5] Department of Climate Change and Energy Efficiency. "About the RET". Available http://www.climatechange.gov.au/en/government/initiatives/renewable-target/need-ret.aspx. Viewed 28 June 2012.

[6] Department of Climate Change and Energy Efficiency. "Fact Sheet: Enhanced Renewable Energy Target". Available http://www.climatechange.gov.au/government/initiatives/renewable-target/fs-enhanced-ret.aspx . Viewed 28 June 2012.

The Large-scale Renewable Energy Target

The LRET retains the RET's existing floating price, fixed-quantity structure, and is available only to large-scale power generation, such as hydro, wind, solar, biomass, and geothermal. The LRET target is 41,000 GWh of renewable energy by 2020 (4,000 GWh less than the total national RET scheme).

For information about generation under the national RET scheme so far, and an analysis of potential investment under the scheme to 2020, see Chapter 2, Section 2.3.3.

1.4 The 2012 ESOO scenarios

In 2012, AEMO developed six planning scenarios for the purposes of energy planning, with each scenario reflecting different levels of economic growth, industrial energy demand, rooftop PV penetration, energy efficiency, and small non-scheduled generation.

The energy and maximum demand projections used to develop each region's supply-demand outlook are based on three of these scenarios: Fast World Recovery, Planning, and Slow Growth. For simplicity, these are referred to throughout the ESOO as the high, medium and low scenarios, respectively.

Table 1-2 lists the names of the six planning scenarios developed in 2012, indicating the scenarios used to develop the regional supply-demand outlooks (for more information about the scenarios, see the 2012 Scenarios Descriptions report).[7]

Table 1-2 — AEMO scenarios for the 2012 ESOO

2012 AEMO scenarios	2012 ESOO reference
Scenario 1 - Fast Rate of Change	-
Scenario 2 - Fast World Recovery	High
Scenario 3 - Planning	Medium
Scenario 4 – Decentralised World	-
Scenario 5 - Slow Rate of Change	-
Scenario 6 - Slow Growth	Low

Generally, projections involve a series of realistic, scenario-based hypotheticals, while a forecast represents a single best guess at future outcomes based on current information. In this context, the Planning scenario is based on AEMO's best estimate of the future direction of major drivers. Designed as a central growth scenario, the Planning (medium) scenario includes currently legislated carbon policies, and is based on the Australian Treasury's core scenario[8], as well as currently estimated rates of new technology development.

[7] AEMO. "2012 Scenarios Descriptions". Available http://www.aemo.com.au/planning/2418-0005.pdf. Viewed 28 June 2012.

[8] The Australian Government's Treasury and the Department of Climate Change and Energy Efficiency modelled the potential economic impacts of reducing emissions over the medium and long term, proposed in the 'Strong Growth, Low Pollution, Modelling a Carbon Price' report, released on 10 July 2011. Available http://archive.treasury.gov.au/carbonpricemodelling/content/default.asp. Viewed 28 June 2012.

1.5 Content and structure of the 2012 ESOO

Executive summary, provides the ESOO's key messages.

Chapter 1, Introduction, provides information about the 2012 ESOO and AEMO's responses to emerging issues affecting national energy planning.

Chapter 2, National investment outlook, provides information about AEMO's most recent analysis of current investment opportunities, as well as providing background information about key investment drivers and their impact on supply and demand.

Chapter 3, Regional investment outlook, provides information about the individual investment outlooks for each NEM region over the 10-year outlook period (2012–13 to 2021–22). This includes information about the supply-demand outlooks, and the timing and magnitude of regional low reserve condition (LRC) points.

List of measures and abbreviations lists the units of measure and abbreviations used throughout the ESOO.

Glossary and list of company names provides a glossary of terms and a list of the companies referred to throughout the ESOO.

1.6 Links to supporting information

This section provides links to documents and web pages with supporting information about the NEM and the electricity industry.

Information source	Website address
Supply-Demand Calculator and Tutorials	http://www.aemo.com.au/Electricity/Planning/Electricity-Statement-of-Opportunities/Supply-Demand-Calculator-and-Tutorials
National Energy Forecasting Report	http://www.aemo.com.au/en/Electricity/Forecasting/2012-National-Electricity-Forecasting-Report
Generator Information Page	http://www.aemo.com.au/Electricity/NEM-Data/Generation-Information
Historical Market Information Page	http://www.aemo.com.au/Electricity/Planning/Related-Information/Historical-Market-Information
2012 Power System Adequacy – Two Year Outlook	http://www.aemo.com.au/en/Electricity/Market-and-Power-Systems/Power-System-Adequacy-Two-Year-Outlook
MT PASA	http://www.aemo.com.au/Electricity/NEM-Data/Outlook-PASA-Data
Energy Adequacy Assessment Projection (EAAP)	http://www.aemo.com.au/en/Electricity/Market-and-Power-Systems/Energy-Adequacy-Assessment-Projection
Economic Outlook Information Paper	http://www.aemo.com.au/en/Electricity/Forecasting/2012-Information-Papers
Rooftop PV Information Paper	http://www.aemo.com.au/en/Electricity/Forecasting/2012-Information-Papers
Wind Contribution to Peak Demand	http://www.aemo.com.au/en/Electricity/Planning/Related-Information/Wind-Contribution-to-Peak-Demand
Gas Reserve Update	http://www.aemo.com.au/en/Electricity/Planning/Gas-Statement-of-Opportunities/Gas-Reserve-Update
2011–12 NEM Demand Review Information Paper	http://www.aemo.com.au/en/Electricity/Forecasting/2012-Information-Papers
Maps and Network Diagrams	www.aemo.com.au/en/Gas/Planning/Maps-and-Diagrams
New Investors' Guide	www.aemo.com.au/en/Electricity/Planning/2011-Victorian-Annual-Planning-Report/Appendices
Introduction to the Australian NEM	http://www.aemo.com.au/~/media/Files/Other/corporate/0000-0262%20pdf.pdf
Joining the NEM Guide	http://www.aemo.com.au/en/Electricity/Planning/Electricity-Statement-of-Opportunities/2011-ESOO-Electronic-Information/~/media/Files/Other/planning/ESOO2011_CD/documents/Attachment_2%20pdf.ashx

CHAPTER 2 - NATIONAL INVESTMENT OUTLOOK

Summary

This chapter presents AEMO's latest assessment of generation and demand-side investment opportunities in the NEM, an analysis of the major drivers of investment, and an overview of current generation investment interest.

AEMO identifies investment opportunities by assessing the ability of existing and committed generation and demand-side participation (DSP) to supply annual energy and maximum demand and satisfy reliability requirements. Reliability requirements are largely dictated by the Reliability Standard, which defines the level of supply adequacy for each region, and places a limit on the amount of expected unserved energy.

For links to supporting information relevant to this chapter (published separately), see Section 2.5.

Capacity and energy-driven investment opportunities

The ESOO identifies two types of investment opportunities:

- Capacity-driven opportunities are based on supply-demand outlook results, coincide with periods of supply scarcity, and are indicated by the timing of the low reserve condition (LRC) point in each region.
- Energy-driven opportunities are based on long-term annual energy trends and changes to the generation mix, and are indicated through market simulations to assess expected unserved energy.

The 2012 ESOO supply-demand balance indicates capacity-driven opportunities in Queensland in 2020–21, Victoria in 2018–19, and South Australia in 2019–20, which is a significant deferral in terms of timing since the 2011 ESOO.

Potential energy-driven investment opportunities have also been deferred, with no regions expected to experience a significant energy deficit within the 10-year outlook period.

These changes are mainly due to changed energy and maximum demand projections for 2012.

Key investment drivers

Key NEM investment drivers in 2012 involve the following:

- AEMO's latest energy and maximum demand projections have fallen considerably since 2011.
- Small-scale generation investment has increased rapidly over the last three years.
- The Large-scale Renewable Energy Target (LRET) is driving continued investment in wind generation capacity.
- Average spot market prices have been falling in every region since 2007–08.

Current investment interest in the NEM

Current investment interest in the NEM is focussed on renewable and peaking generation, with publicly announced proposals involving over 13,000 MW of wind generation capacity and over 11,000 MW of open-cycle gas turbine (OCGT) generation capacity. There is less interest in base load generation investment, with publicly announced proposals involving approximately 3,300 MW of black coal generation capacity, and approximately 3,000 MW of combined-cycle gas turbine (CCGT) generation capacity.

2.1 Investment opportunities in the NEM

2.1.1 Capacity-driven investment opportunities

This section presents an overview of the supply-demand outlook, including the results for each region, and the changes since the 2011 ESOO.

Capacity-driven investments involve demand-side or generation investments that aim to provide capacity at times of high demand. The regional reserve deficits indicate potential opportunities for this kind of investment.

Supply-demand outlook results

The supply-demand outlook provides an assessment of existing and committed generation and DSP, and its ability to supply each region's annual energy and maximum demand and satisfy reliability requirements. These requirements are dictated by the Reliability Standard, which defines the minimum level of supply adequacy for each region, and places a limit on the amount of expected unserved energy. The assessment is conducted for each region over a 10-year outlook period, and the first reserve deficit is indicated by the LRC point.

The LRC points take into account the scope for reserve-sharing by neighbouring regions. The LRC points in Victoria and South Australia are closely aligned due to their ability to share considerable reserves through interconnectors. Tasmania's demand is typically quite low at the time of the summer maximum demand in the mainland regions, while Victorian demand is also typically quite low at the time of Tasmania's winter maximum demand. This enables Tasmania and the mainland regions to take advantage of considerable reserve sharing opportunities at times of maximum demand, via the Basslink interconnector. For information about key supply-demand outlook inputs and methodologies, see Section 2.2.

Table 2-1 provides an overview of the supply-demand outlook under the low, medium and high scenarios, showing the timing and magnitude of reserve deficits in each region. The reserve deficit indicates the additional capacity required to meet the region's minimum reserve level (MRL) at the time of the projected maximum demand for the relevant year. For more information about the MRLs, see Section 2.2.

Table 2-1 — NEM supply-demand outlook summary

Region	Low scenario		Medium scenario		High scenario	
	LRC point	Reserve deficit (MW)	LRC point	Reserve deficit (MW)	LRC point	Reserve deficit (MW)
Queensland	>2021–22	-	2020–21	79	2016–17	93
New South Wales	>2021–22	-	>2021–22	-	>2021–22	-
Victoria	2021–22	54	2018–19	115	2015–16	50
South Australia	>2021–22	-	2019–20	24	2015–16	3
Tasmania (summer)	>2021–22	-	>2021–22	-	>2021–22	-
Tasmania (winter)[a]	>2022	-	>2022	-	>2022	-

a. Tasmania's winter outlook is included because the maximum demand occurs during winter.

Under the medium scenario, no region is predicted to experience an LRC point until 2018–19, when Victoria is predicted to have a deficit of 115 MW. This is a significant change from the 2011 ESOO, which projected a 341 MW LRC point for Queensland in 2013–14 and deficits in 2018–19 of over 150 MW in every region except Tasmania.

Since the 2011 ESOO, a comparison of the LRC points under the medium scenario shows the following results:

- Queensland requires additional investment by summer 2020–21, which defers the LRC point by seven years.
- New South Wales does not require additional capacity-driven investment for the outlook period, which defers the LRC point by at least three years.
- Victoria requires additional capacity-driven investment by summer 2018–19, which defers the LRC point by four years.
- South Australia requires additional capacity-driven investment by summer 2019–20, which defers the LRC point by five years.
- Tasmania does not require additional capacity-driven investment for the outlook period, which is consistent with the 2011 ESOO.

The differences in LRC point timings are mainly due to changes to the maximum demand projections (for more information, see Section 2.3.1), which are analysed in detail in the National Energy Forecasting Report (NEFR).[1]

2.1.2 Energy-driven investment opportunities

This section summarises the results of the latest assessment of expected unserved energy, and AEMO's latest estimates of potential energy deficits over the outlook period. Energy-driven investments are typically generation investments that maximise the energy output of a generating unit over time, and include base load and renewable energy generating units that depend on the availability of a particular resource, such as wind or solar energy. Generation of this type generally has lower operating costs than peaking or intermediate generation.

The energy deficit estimates indicate potential energy-driven investment opportunities, which are represented by expected unserved energy resulting from market simulations to 2021–22. An energy adequacy assessment for Tasmania is presented separately, because the high proportion of hydroelectric generation in this region makes it more likely to be energy-limited than capacity-limited.

Assessment of expected unserved energy

The supply-demand outlook results in Section 2.1.1 highlight when an individual region's expected unserved energy exceeds 0.002% of annual energy consumption.[2] This is not expected to occur until 2018–19, in Victoria. This section presents the expected unserved energy for the entire NEM, under the medium scenario, in the years 2018–19 to 2021–22.

The 2011 ESOO included a basic assessment of expected unserved energy, which made several assumptions about generator reliability and inter-regional support. This assessment identified small energy deficits in 2020–21 in every region except Tasmania (for more information, see the 2011 ESOO, Chapter 8[3]). The assessment was updated in 2012 based on new inputs (including new energy and maximum demand projections) and a more comprehensive set of market simulations.

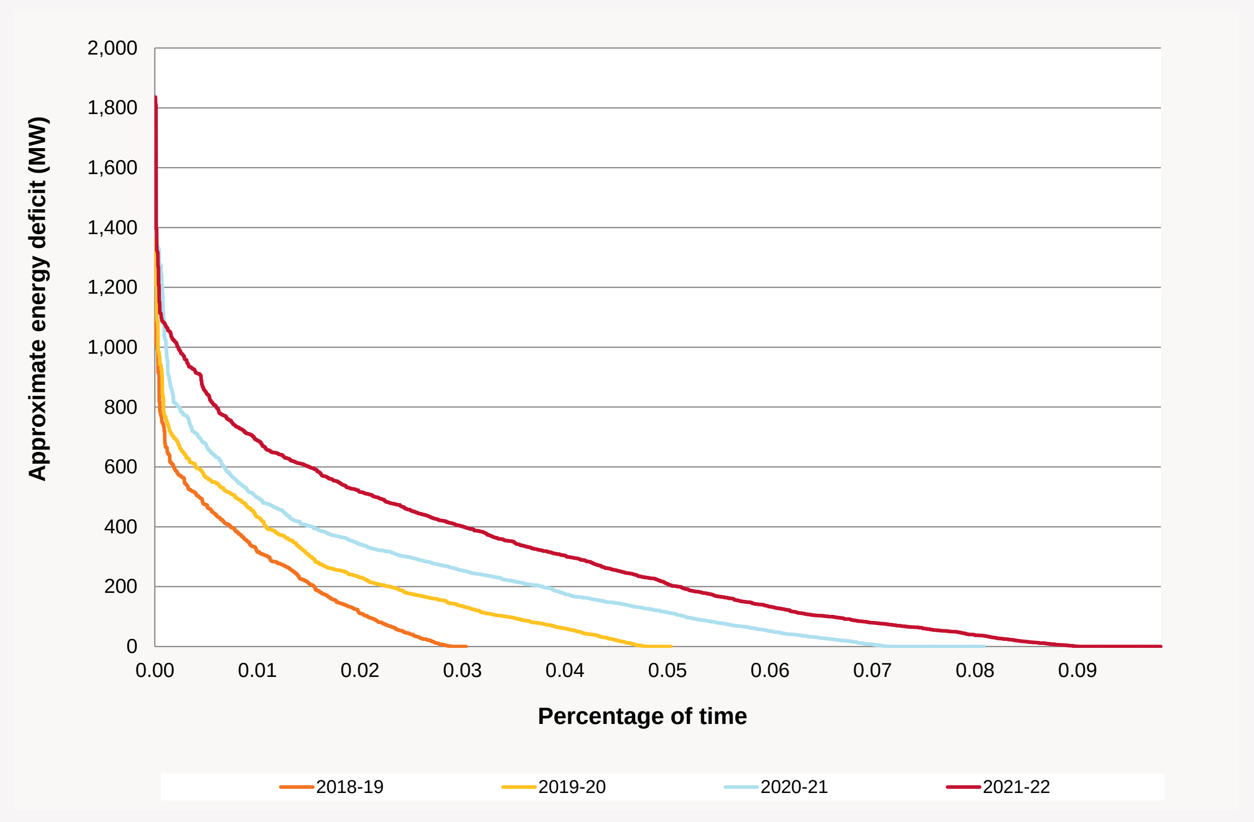
Figure 2-1 shows the updated expected unserved energy in the NEM from 2018–19 to 2021–22, with the level of unmet load (in MW) represented on the vertical axis, and the percentage of time during the year it is expected to occur represented on the horizontal axis. As an example of how to read this figure, expected unmet load of 700 MW or more is forecast to occur in 2021–22 for less than 0.01% of the time (or less than one hour).

[1] AEMO. "National Energy Forecasting Report 2012". Available http://www.aemo.com.au/en/Electricity/Forecasting. Viewed 4 July 2012.
[2] This is based on the Reliability Standard. For more information, see Section 2.2.2.
[3] AEMO. "2011 Electricity Statement of Opportunities". Available http://www.aemo.com.au/en/Electricity/Planning/Electricity-Statement-of Opportunities/2011-ESOO-Electronic-Information/Electricity-Statement-of-Opportunities-ESOO. Viewed 4 July 2012.

The expected unserved energy has decreased since 2011 due to the changed annual energy projections, and is relatively small when compared to the output of a typical base load generating system. Based on current generation capacity in the NEM, this suggests there are limited investment opportunities of this type. Policies like the national Renewable Energy Target (RET) scheme, however, are providing a strong additional driver for this type of investment. For more information about the national RET scheme, including the historical and forecast energy output of generators contributing to the LRET target, see Section 2.3.3.

While expected unserved energy over the outlook period is small, the additional generation capacity or DSP required at times of unmet load is still substantial, indicating opportunities for new peaking generation. For more information about capacity-driven investment opportunities for each region, see Section 2.1.1.

Figure 2-1 — Expected unserved energy in the NEM, 2018–19 to 2021–22



Tasmanian energy adequacy assessment

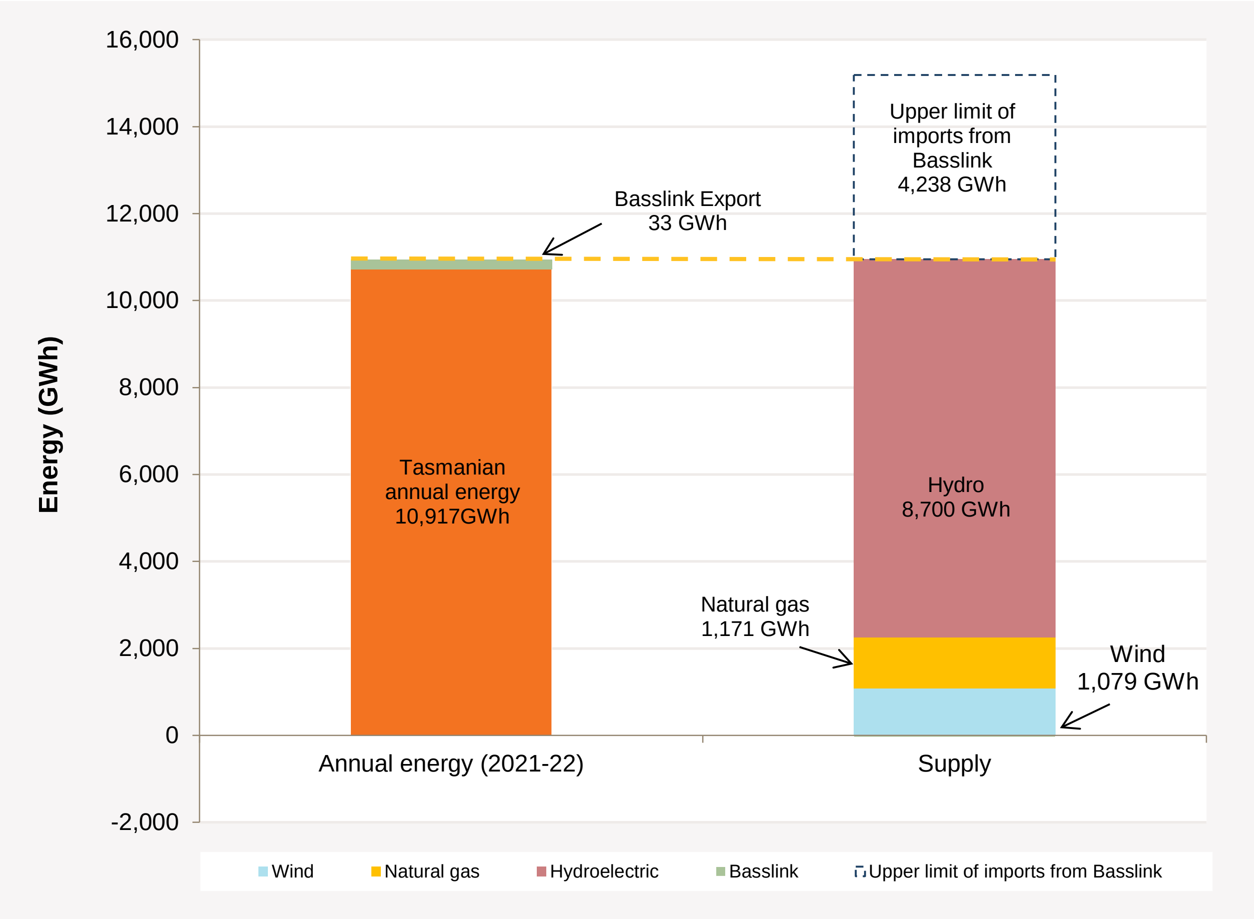
Tasmania principally depends on hydroelectric generation to meet its local energy requirements, and as a result tends to be an energy-limited region. Figure 2-2 provides a high-level energy adequacy assessment for Tasmania for the end of the outlook period (2021–22), which depends on several key assumptions[4]:

- The medium scenario annual energy projection.
- Existing CCGT generation (208 MW) running at 60% capacity factor.
- Existing OCGT generation (178 MW) running at 5% capacity factor.
- Existing and committed wind generation capacity (308 MW) running at 40% capacity factor.
- Annual hydroelectric energy output (8,700 GWh) consistent with long-term expectations.
- Basslink import capabilities of 480 MW.

[4] The assumed capacity factors for thermal units (OCGT and CCGT) are based on average simulated outcomes in AEMO's previous planning studies, such as the NTNDP. The wind capacity factor is based on the historically observed capacity factor of Tasmanian wind generation.

Subject to additional limitations or drought conditions affecting the operation of Tasmania's hydroelectric power stations, no energy shortfalls are predicted for Tasmania by 2021–22. This assessment does not specifically account for scenarios where droughts or significantly reduced rainfall place additional limitations on hydroelectric generation. This type of analysis is provided by AEMO's quarterly Energy Adequacy Assessment Projection (EAAP), which uses time-sequential studies to provide a 2-year outlook quantifying the impact of energy limitations under multiple scenarios.[5]

Figure 2-2 — Tasmanian energy adequacy assessment, 2021–22



[5] AEMO. Available http://www.aemo.com.au/en/Electricity/Market-and-Power-Systems/Energy-Adequacy-Assessment-Projection. Viewed 4 July 2012.

2.2 Methodology and key inputs to the supply-demand outlook

This section provides information about the methodology and inputs used in the supply-demand outlook, including updated information about MRLs and the contribution of intermittent generation to maximum demand.

2.2.1 The supply-demand calculator

The supply-demand calculator generates 10-year reliability outlooks for each region. The calculator is a spread sheet tool that uses a linear programming approach to co-optimise generation dispatch and interconnector flows (subject to minimising reserve deficits). Reserve surpluses are shared between regions according to predetermined sharing relationships.

The underlying input data and assumptions used by the calculator include the following:

- Projected generation capacities, which include only existing and committed generating units.
- The 10% probability of exceedence (POE) maximum demand projections for each region.
- Levels of committed DSP.
- Network capabilities for each region's transmission network and the relevant interconnectors, which are based on the existing network and committed augmentations.
- The MRLs, which represent the amount of surplus installed capacity required to meet the Reliability Standard.

The 2012 ESOO supplementary information includes an interactive version of the supply-demand calculator, enabling interested parties to vary assumptions and assess alternative scenarios. This also includes a tutorial (The Supply-Demand Calculator) explaining how to use the calculator to determine the impact of changing assumptions, and how to view and interpret supply-demand outlook results.

Modelling network capability

The supply-demand calculator models transmission network capability using a set of system-normal network constraint equations, which are extracted from AEMO's Market Management System (MMS) or, where appropriate, produced from a detailed analysis of network load-flow snapshots. These constraint equations are adjusted to take account of advice from the jurisdictional planning bodies (JPBs) about how network capabilities may vary with time and operating conditions, particularly due to the impact of committed transmission projects.

Inter-regional reserve sharing

The supply-demand calculator and the MRLs must account for the reserve-sharing potential between neighbouring regions. The amount of capacity that can be contributed between regions via interconnectors mainly depends on demand diversity and transmission network limitations. This allows a region's supply-demand outlook to be optimised so that regions with excess available capacity can support neighbouring regions that are unable to meet their reserve requirements locally.

For more information about how inter-regional reserve sharing is estimated, including detailed representations of the regions' ability to support each other under different demand conditions (in the form of a series of reserve-sharing curves for each pair of neighbouring regions), see Chapter 6 of the 2011 ESOO.[6]

2.2.2 Reliability and the minimum reserve levels

In the context of the NEM, reliability refers to the likelihood of having sufficient supply to meet demand, and is measured in terms of accumulated unserved energy over time, and expressed as a percentage of the total energy requirement over the same timeframe.

[6] See note 3.

The Reliability Standard[7] established by the Australian Energy Market Commission's (AEMC) Reliability Panel defines the minimum acceptable level of reliability to be met in each region. The Reliability Standard currently specifies that over the long term, the maximum expected regional unserved energy should be no more than 0.002% of a region's annual energy consumption.

The LRC point indicates a year when unserved energy is projected to exceed the Reliability Standard because the supply capacity is too low relative to the expected maximum demand. An LRC point does not necessarily signify that load shedding will occur, however, continued operation with a low reserve indicates the system may not meet the Reliability Standard over the long term.

The total supply capacity required to meet the Reliability Standard is generally higher than the expected maximum demand because of generator outages, variations in generator operating schedules, and the duration of high-demand periods. To accommodate this, AEMO translates the Reliability Standard into a required safety margin of surplus generation capacity that can be applied operationally. By convention, this margin is referred to as a MRL and is expressed relative to a region's 10% POE maximum demand projection, including any DSP.

The MRLs are calculated using detailed market simulations, and the MRLs used in the 2012 supply-demand outlook have not changed since 2011. For more detailed information about the MRL calculation process, see Chapter 6 of the 2011 ESOO.[8]

Minimum reserve level reviews

AEMO is currently reviewing the process to calculate the MRLs and formulate the ESOO's supply adequacy assessment.

Regular reviews ensure the MRLs remain appropriate as the power system evolves. Supply adequacy is particularly sensitive to aspects of the power system that change over time, such as changes in demand diversity, the location and reliability of generation capacity, and any significant transmission network augmentations.

The current review aims to identify potential accuracy and efficiency gains from moving away from pre-calculated MRL values, instead integrating the reserve requirement calculations within the supply adequacy assessment itself. AEMO intends to consult with stakeholders on the outcome of this review, and to implement any new processes in future ESOOs.

2.2.3 The contribution of intermittent generation to maximum demand

Wind generation

The installed capacity of wind generation in the NEM is approximately 2,135 MW, with an additional 608 MW of committed wind generation planned for connection in 2012 and 2013.[9] The intermittent nature of wind, however, means that wind generation at the time of a regional maximum demand may be significantly lower than its total installed capacity.

AEMO analyses historical wind farm outputs to predict the future contribution of wind generation to capacity requirements for the supply-demand outlook. An estimated contribution factor for summer and winter maximum demand is then calculated and applied to existing and committed wind generation in the relevant region.[10]

[7] Australian Energy Market Commission. "Guidelines & Standards". Available http://aemc.gov.au/Panels-and-Committees/Reliability-Panel/Guidelines-and-standards.html. Viewed 4 July 2012.
[8] See note 3.
[9] This estimate includes all registered scheduled, semi-scheduled and non-scheduled wind generation. For more information about scheduled, semi-scheduled, and non-scheduled generating system classification types, see Section 2.4.1.
[10] AEMO. "Wind Contribution to Peak Demand". Available http://www.aemo.com.au/en/Electricity/Planning/Related-Information/Wind-Contribution-to-Peak-Demand. Viewed 31 July 2012.

Table 2-2 lists the peak contribution factors for wind generation for each region. The wind contribution factors have been updated since the 2011 ESOO to reflect updated generation data, which includes new wind farms that have entered the NEM. Some changes also resulted from a review of the methodology used in the calculations, which includes the following:

- Improving the analysis by using a more accurate measure of historical generation, which is based on dispatched outputs, and by shifting the basis of the calculations from 30-minute settlement periods to 5-minute dispatch intervals.
- Using wind generation data and demand data over only the last three to four years (as opposed to when data collection first began) to account for the current levels of wind generation diversity (in some regions) and potential changes in bidding behaviour.
- Excluding the output of wind farms as they are being constructed (prior to commissioning).

Table 2-2 — Maximum demand contribution factors – wind generation (%)

Region[a]	Summer	Winter
New South Wales	2.2	4.6
Victoria	6.5	7.2
South Australia	8.3	7.5
Tasmania	3.5	2.9

a. No wind contribution factors have been calculated for Queensland due to limited data. There are no existing or committed scheduled or semi-scheduled wind farms in Queensland, so they are not included in the supply-demand outlook.

Rooftop photovoltaic (PV) generation

Although there are no registered solar power generators in the NEM, the capacity of rooftop photovoltaic (PV) generation connected to the NEM distribution network has increased rapidly in recent years, with estimated capacity growing from less than 100 MW at the end of 2009 to 1,450 MW in February 2012.[11] Rooftop PV output is intermittent and its contribution to regional maximum demand is uncertain.

The supply-demand calculator does not model existing rooftop PV generation with other generation types because of its small, decentralised nature. Instead, it accounts for this type of generation as a maximum demand projection reduction (or offset).

Table 2-3 lists AEMO's estimates for the peak contribution factors for rooftop PV in each region, established in 2012. Similarly to the wind contribution factors, this can be applied to a region's estimated rooftop PV capacity to approximate its contribution to that region's maximum demand (in MW), which is deducted from the region's maximum demand projection.[12]

[11] AEMO. "Rooftop PV Information Paper". Available http://www.aemo.com.au/en/Electricity/~/media/Files/Other/forecasting/Rooftop_PV_Information_Paper.ashx. Viewed 4 July 2012.
[12] These are initial estimates only, based on a preliminary investigation of rooftop PV system outputs in the NEM. For more information, see note 11.

Table 2-3 — Maximum demand contribution factors – rooftop PV generation (%)

Region[a]	Summer
Queensland	28
New South Wales	29
Victoria	35
South Australia	38

a. No rooftop PV contribution factor has been calculated for Tasmania because the Tasmanian maximum demand typically occurs in the winter, either in the evening or early morning.

2.3 Drivers of investment in the NEM

Generation and demand-side investment is shaped by the economic environment, climate change policy developments, and new generation technologies, all of which impact the economic drivers underlying existing NEM operations and new investment. This section presents information about the following key drivers of NEM investment:

- The annual energy and maximum demand projections (see Section 2.3.1).
- Small-scale generation uptake, which impacts annual energy (see Section 2.3.2).
- The LRET, which drives investment in renewable energy (see Section 2.3.3).
- NEM spot market prices and forward contracts (see Section 2.3.4).

The impacts these drivers have on the NEM's generation and fuel supply mix are also apparent from recent changes to the capacity and output of NEM generation (see Section 2.3.5).

The full extent of the impact from some policy drivers, such as the suite of measures included in the Australian Government's Clean Energy Future plan, will become more apparent as the measures are introduced. For a detailed analysis of some of these policies, see the 2012 NEFR[13] and 2012 Forecasting Information Papers.[14]

2.3.1 Annual energy and maximum demand projections

This section presents a high-level summary of the 2012 annual energy and maximum demand projections (medium scenario) for the 10-year outlook period, with a focus on changes since the 2011 ESOO. These projections represent key inputs into the supply-demand outlook, as well as providing important information for potential investment in the NEM.

In 2012, AEMO developed its own annual energy and maximum demand projections for each region for the first time. For more information about the new projections, see the 2012 NEFR.[15] For more information about the projections for each region, see Chapter 3.

Maximum demand projection medium scenario summary

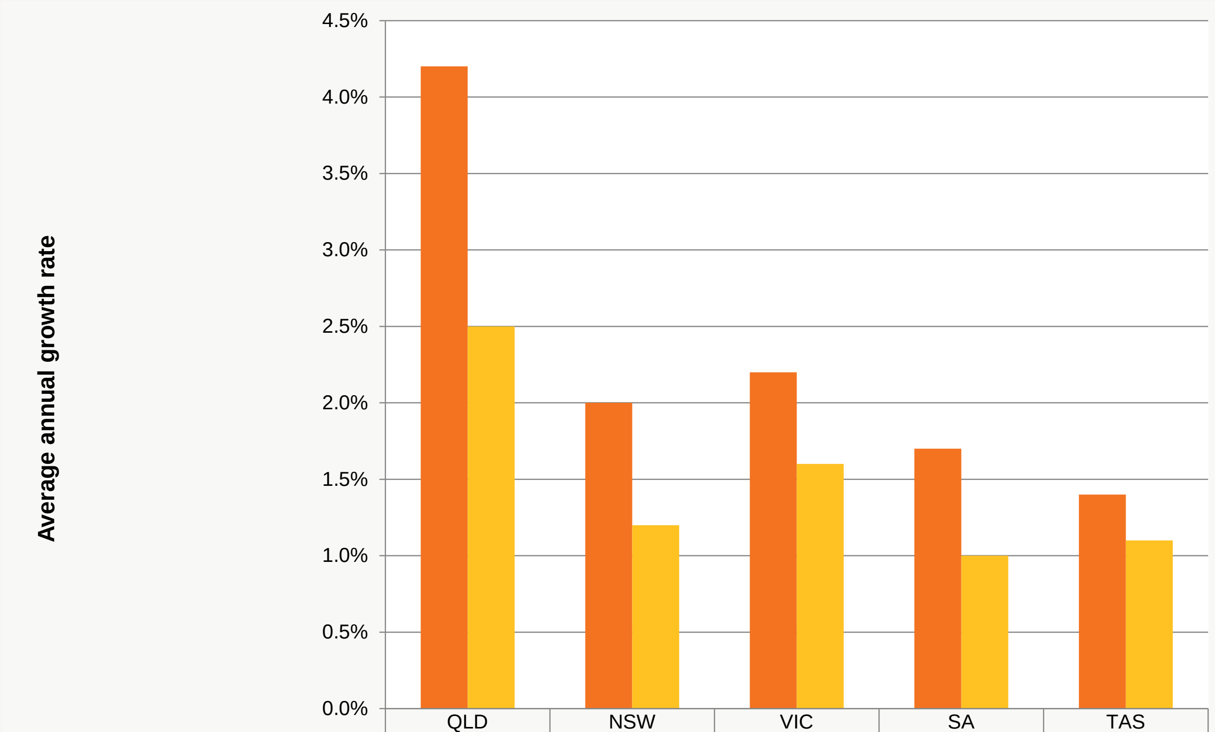
The maximum demand projection under the medium scenario has decreased since the 2011 ESOO.

Figure 2-3 shows the summer 10% POE maximum demand projection growth rates for each mainland region for 2011 and 2012.

[13] AEMO. Available http://www.aemo.com.au/en/Electricity/Forecasting/2012-National-Electricity-Forecasting-Report. Viewed 10 July 2012.
[14] AEMO. Available http://www.aemo.com.au/en/Electricity/Forecasting/2012-Information-Papers. Viewed 4 July 2012.
[15] See note 13.

A winter 10% POE maximum demand projection is shown for Tasmania, which is when this region experiences its maximum demand.

Figure 2-3 — Average annual maximum demand projection growth rates, 2011 to 2012 (medium scenario)



	QLD	NSW	VIC	SA	TAS
2011 MD forecast annual growth rate	4.2%	2.0%	2.2%	1.7%	1.4%
2012 MD forecast annual growth rate	2.5%	1.2%	1.6%	1.0%	1.1%

Several factors contributed to the changed projections:

- A moderation in gross domestic product (GDP), especially in the short term, as a result of the changed economic outlook. For more detailed information about the latest economic projections, see the AEMO website.[16]
- Reduced manufacturing consumption in response to the high Australian dollar.
- The significant penetration of rooftop PV generation, which will contribute varying amounts to maximum demand, depending on its location (for more information, see Section 2.3.2).
- Consumer responses (commercial and residential) to rising electricity costs and energy efficiency measures.

Table 2-4 summarises the changes to the maximum demand projections for each region.

[16] AEMO. “Economic Outlook”. Available http://www.aemo.com.au/en/Electricity/Forecasting/2012-Information-Papers. Viewed 4 July 2012.

Table 2-4 — Changes to the summer 10% POE maximum demand projections since the 2011 ESOO (medium scenario)

Region	Change in 2012–13 (MW)	Change in 2020–21 (MW)	Change in average annual growth rate[a]
Queensland	-1,908	-3,795	-1.3%
New South Wales	-2,056	-3,463	-0.8%
Victoria	-746	-1,247	-0.4%
South Australia	-359	-597	-0.6%
Tasmania (winter 2013 and 2021)	-149	-172	0.04%

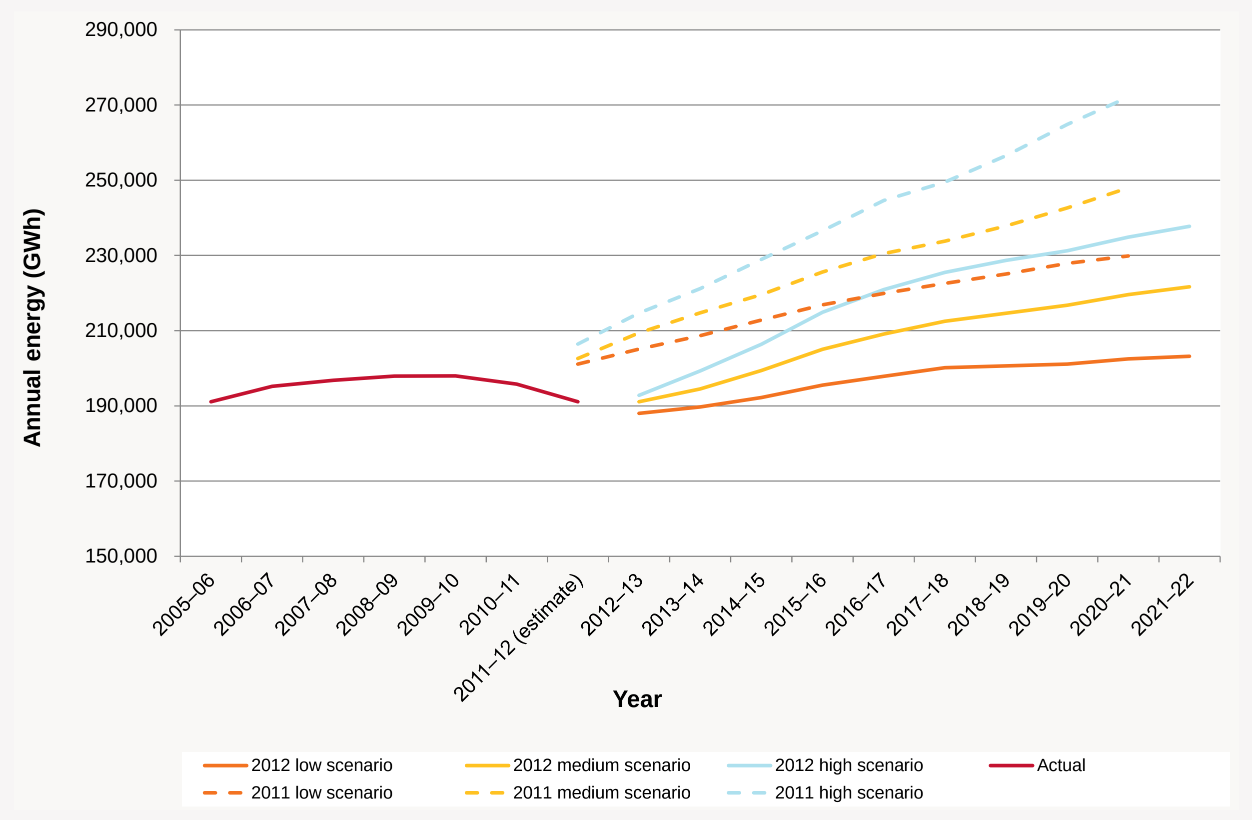
a. Growth rate calculated from 2012–13 to 2020–21 (2013 to 2021 for Tasmania).

Annual energy projection summary

Since 2009–10, annual energy in the NEM has been decreasing by approximately 1.7% per year. This was previously viewed as a short-term change stemming from the global financial crisis and its impact on the domestic economy, and the 2011 ESOO predicted a return to relatively strong growth in annual energy for all five regions. However, a further reduction in annual energy in 2011–12 required a review of energy trends, and ultimately a downward revision of the projections.

Figure 2-4 compares the 2011 and 2012 annual energy projections for the low, medium, and high scenarios. Under the 2012 medium scenario there is virtually no projected growth in annual energy from 2011–12 to 2012–13, representing an 8.8% decrease since 2011.

Figure 2-4 — Comparison of the NEM-wide energy projections (low, medium, and high scenarios)



2.3.2 Small-scale generation uptake

Installations of small-scale rooftop PV systems have increased rapidly over the last five years. After analysing this increase in 2012, AEMO produced a range of projections involving the potential future contribution of rooftop PV to annual energy and maximum demand.[17] These estimates have been included in AEMO's latest projections as reductions (or offsets) in annual energy and maximum demand (for more information about rooftop PV's contribution to maximum demand, see Section 2.2.3).

Figure 2-5 shows the projected annual energy contribution from rooftop PV from 2012–13 to 2021–22 for each region under the medium scenario. The total annual energy contribution from rooftop PV is predicted to exceed 7,500 GWh in 2021–22.

[17] AEMO. Available http://www.aemo.com.au/en/Electricity/~/media/Files/Other/forecasting/Rooftop_PV_Information_Paper.ashx. Viewed 4 July 2012.

Figure 2-5 — Projected annual energy contribution from rooftop PV (medium scenario)

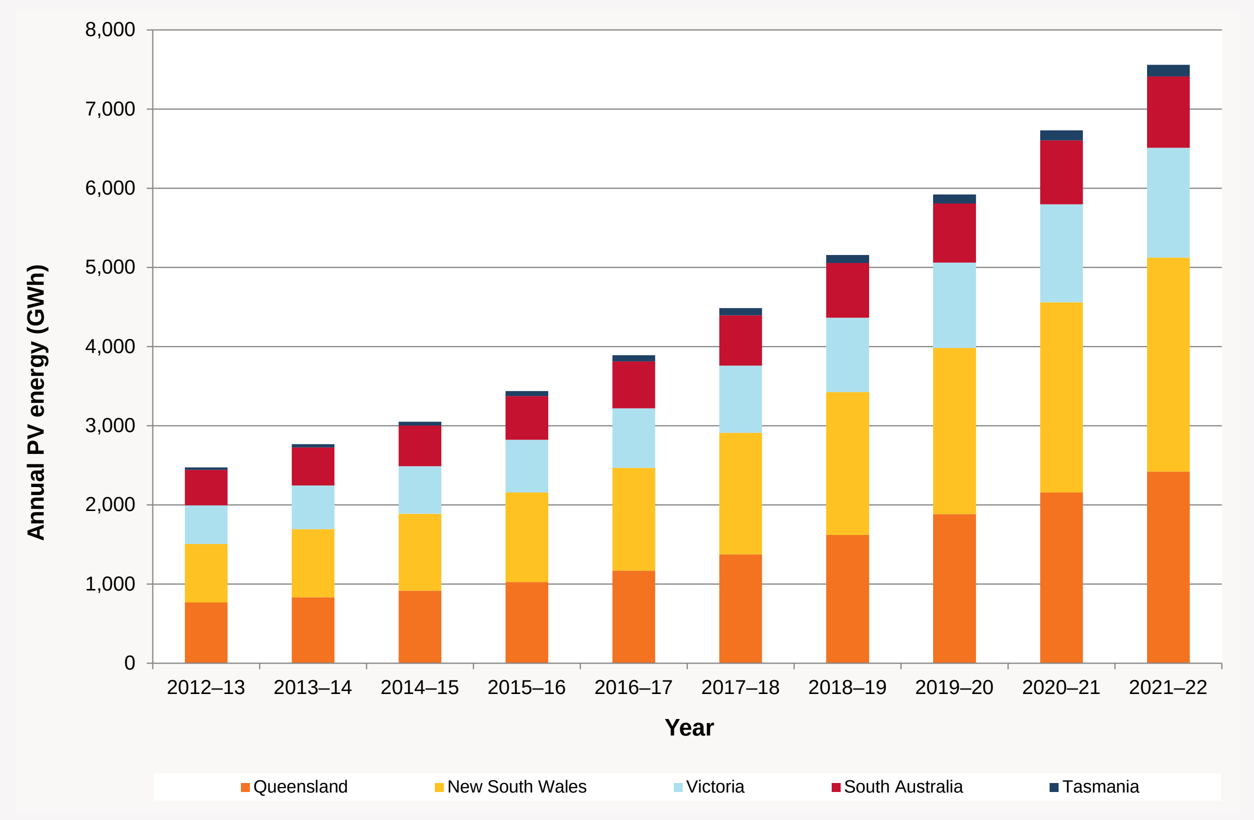


Table 2-5 lists the projected annual energy contribution from rooftop PV from 2012–13 to 2021–22 for each region under the medium scenario, expressed as a percentage of the annual energy projection for that year.

South Australia is expected to have the highest penetration of rooftop PV, which under this scenario is predicted to contribute 6.4% of the total annual energy for the region in 2021–22.

Table 2-5 — Projected annual energy contribution from rooftop PV as a percentage of annual energy (medium scenario)

Year	Queensland	New South Wales	Victoria	South Australia	Tasmania	NEM Total
2012–13	1.5%	1.1%	1.0%	3.4%	0.3%	1.3%
2013–14	1.6%	1.2%	1.1%	3.7%	0.4%	1.4%
2014–15	1.7%	1.3%	1.2%	3.8%	0.5%	1.5%
2015–16	1.8%	1.5%	1.3%	4.1%	0.6%	1.7%
2016–17	1.9%	1.8%	1.5%	4.4%	0.7%	1.9%
2017–18	2.2%	2.0%	1.7%	4.7%	0.8%	2.1%
2018–19	2.6%	2.4%	1.8%	5.0%	0.9%	2.4%
2019–20	3.0%	2.8%	2.1%	5.3%	1.0%	2.7%
2020–21	3.4%	3.1%	2.3%	5.7%	1.2%	3.1%
2021–22	3.7%	3.5%	2.6%	6.4%	1.3%	3.4%

2.3.3 The Large-scale Renewable Energy Target

The LRET and its predecessor policies the national RET scheme and the Mandatory Renewable Energy Target (MRET) have been key drivers of renewable energy investment in the NEM since they began in 2001. For more information about these schemes, see the Australian Government's Clean Energy Regulator website.[18]

The LRET provides large-scale renewable energy generators with an ongoing source of revenue in addition to electricity sales through the NEM, through the creation and sale of Large-scale Generation Certificates (LGCs). Prior to 2011, these certificates were called Renewable Energy Certificates (RECs) and could be created by large-scale and small-scale renewable energy generators.

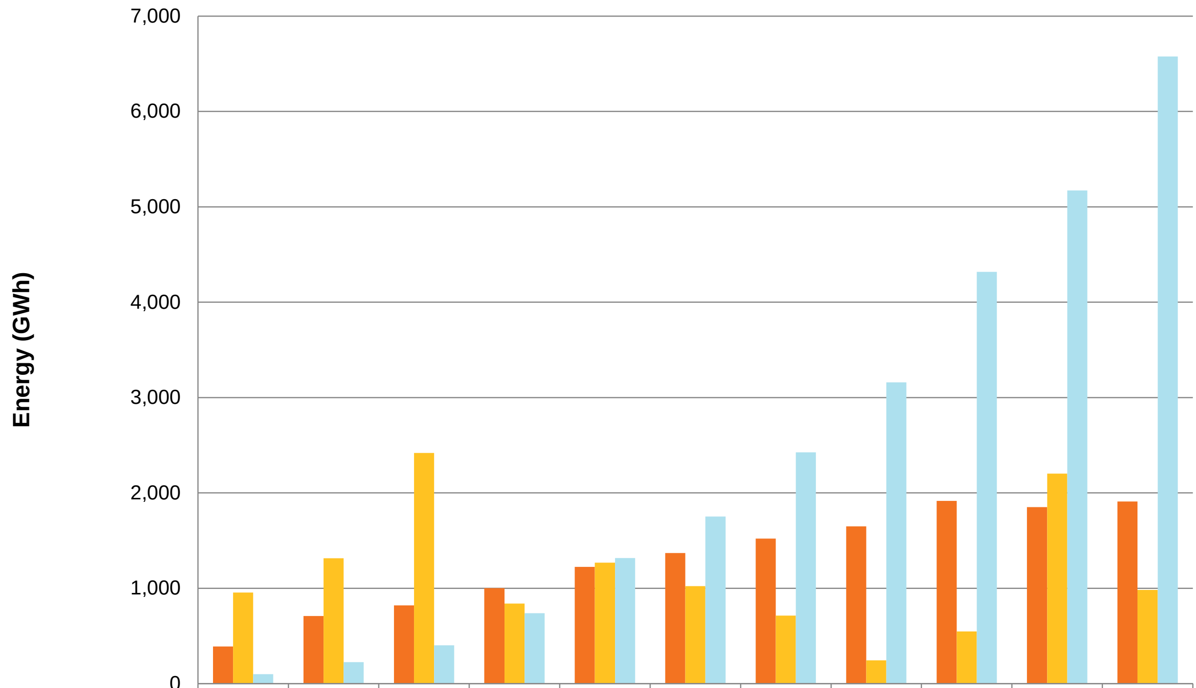
Renewable energy generation

Figure 2-6 shows the energy (in GWh) attributed to RECs and LGCs by large-scale renewable energy generation for each calendar year from 2001 to 2011. The figure is broken down into hydro, wind, and biomass and waste generation, which have accounted for over 99% of the LGCs created since the beginning of the LRET.[19]

Each REC and LGC is issued to an eligible generator through the REC registry, and represents 1 MWh of renewable energy output. The data in Figure 2-6 includes certificates created up to 5 July 2012. Given generators can take up to a year following actual generation to create LGCs for their output, the LGC data for 2011 may be incomplete.

[18] Clean Energy Regulator. Available http://ret.cleanenergyregulator.gov.au/About-the-Schemes/lret. Viewed 4 July 2012.
[19] Generation from rooftop PV, solar water heater units and small-scale wind and hydroelectric generating units has not been included. This data is not restricted to the NEM, and includes all large-scale generation contributing to the LRET target.

Figure 2-6 — Large-scale renewable energy generation for RECs and LGCs[20]



	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Biomass and waste	390	709	822	1,002	1,223	1,368	1,521	1,648	1,916	1,852	1,909
Hydro	956	1,315	2,420	840	1,269	1,022	713	244	547	2,201	982
Wind	100	226	402	738	1,317	1,752	2,426	3,158	4,318	5,172	6,577

The figure provides the following observations:

- There has been strong, steady growth in wind power generation (for more information, see Section 2.3.5).
- Hydroelectric generation has fluctuated, and was lowest during the extreme drought years from 2007 to 2009. The low output in 2011 may not reflect actual generation for that year, as some LGCs for generation in the second half of the year may not have been created yet.
- The LGC creation by biomass and waste generators has increased at an average annual rate of 19% since the beginning of the RET. This includes thermal generation from methane at landfill sites and bagasse-fired generation using sugar cane crop waste.

Forecast REC and LGC contributions to the LRET

This section presents information about the potential contribution of new and existing renewable energy generation to the LRET over the next few years, and is based on a series of high-level estimates established by AEMO. A forecast of future shortfalls in LGCs has been created, based on existing and committed large-scale renewable energy generation and the current surplus of RECs and LGCs.

Under the LRET (and previously the RET), LGCs created in a particular year can be held by generators prior to being sold, or by liable entities (retailers and large electricity customers) after purchasing them, to contribute to the renewable energy target in future years. A liable entity's submission of a REC or LGC to count towards its annual LRET contribution is called 'surrender'.

[20] REC and LGC data from the Register of Large-scale Generation Certificates, managed by the Clean Energy Regulator. Available https://www.rec-registry.gov.au/getSearchPublicRecHoldings.shtml?recType=LGC. Viewed 5 July 2012.

Due to the large number of RECs created in 2009 and 2010 by small-scale rooftop PV and solar water heater units, there is currently a surplus of RECs and LGCs that have been created but not surrendered.[21]

Figure 2-7 shows the annual LRET target from 2001 to 2020[22], as well as an estimate of the number of LGCs that will be created in the future by existing and committed hydro, wind, and biomass and waste generating units. The figure also shows the estimated contribution that existing RECs and LGCs will make to the LRET target until they have all been surrendered in 2016. Other details attached to the figure include the following:

- The number of certificates surrendered each year by liable entities must reach the LRET target.[23]
- Wind and biomass and waste generation totals from 2012 onwards are estimates based on the historical output of existing generators and the expected output of committed generators.
- The estimate of hydroelectric generation from 2012 onwards is based on an average of the annual REC creation by hydroelectric generators from 2001 to 2010.
- The figure's 'Contribution from surplus RECs and LGCs' series is the total of all RECs and LGCs created prior to 2012, but not surrendered by the end of 2011. This pool of certificates has been distributed among future years to show their potential to continue contributing to the LRET. The forecast shows when this surplus is expected to run out, in the absence of new large-scale renewable energy generation.
- The figure also includes a projection of demand for GreenPower, assuming demand to 2020 remains the same as 2010. GreenPower LGCs cannot be used to contribute to the LRET, and so create extra demand in the LGC market. Demand for these LGCs has fluctuated according to customer demand for GreenPower and other contracts for renewable energy supply.[24]
- RECs and LGCs surrendered under the GreenPower Accreditation Program are shown in the year of generation, not the year of surrender (because this is how the data is stored in the REC registry).
- The figure excludes actual LGCs created in 2012.

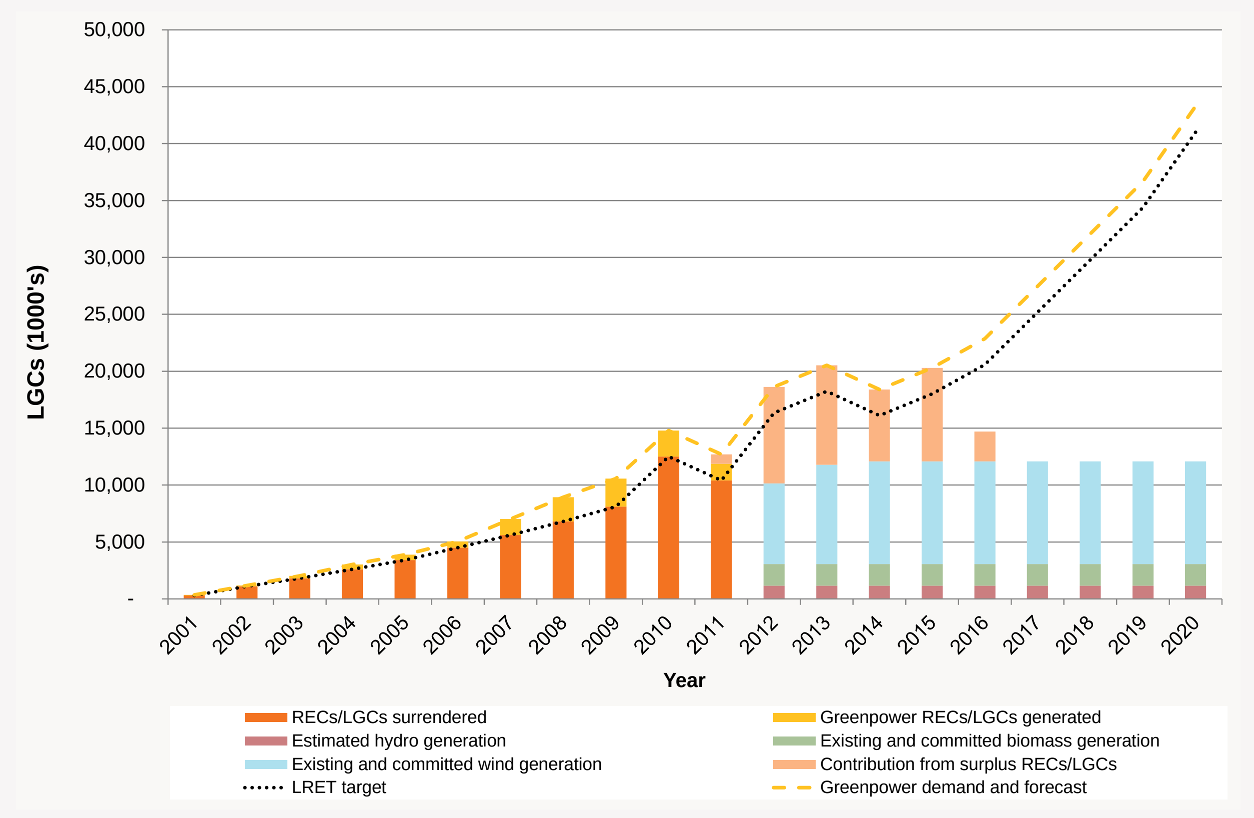
[21] Before the RET was split into the LRET and the SRES, RECs were also created for small-scale rooftop PV and solar water heater units. In 2009 and 2010 there was a sharp increase in the number of RECs created for these technologies, and in 2010 the number of RECs created exceeded the target for that year by three times.

[22] This figure does not include the increase to the LRET to account for output by waste coal mine gas generators (425 GWh in 2012 and 850 GWh for 2013 to 2020, inclusive). It is assumed that this increase in the target will be equal to the output of those generators, which is not relevant to this analysis.

[23] In practice there is some variation between the target and the number of certificates surrendered in a year, because the liability from each party must be estimated in advance. Any variation is corrected in the following year, however, so these variations do not affect this analysis.

[24] Several new desalination plants have entered into contracts with renewable energy generators to purchase LGCs equivalent to their electricity usage. This analysis has not incorporated new demand for GreenPower LGCs from desalination plants, because their future electricity consumption is uncertain. If these plants begin purchasing significant numbers of LGCs in the next few years this will increase the LGC deficit estimates.

Figure 2-7 — Forecast REC and LGC contributions to the LRET



AEMO estimates that enough RECs and LGCs have been created, or are likely to be created from existing generators, to satisfy the LRET and projected GreenPower demand until 2015. Given the scale of the deficit from 2016 onwards, however, this analysis suggests there is still a strong driver for additional investment in large-scale renewable energy technologies under the LRET.

From 2011 to 2015, the LRET grows by an average of 1.9 million LGCs per year. Starting in 2016, however, when the current LGC surplus is predicted to run out, the annual increase in the target grows to 4.6 million LGCs.

Table 2-6 lists the forecast LGC deficits from 2016 to 2020. The first row lists the estimated deficit of LGCs, according to this analysis. The second row lists the estimated wind generation capacity required to supply the forecast LGC deficit for that year, based on the average capacity factor of South Australian wind generation in 2011–12 (33%).

As an example of how to interpret this table, in 2019 it is estimated that based on existing and committed generation capacity there will be a large-scale renewable energy generation shortfall of 24,600 GWh compared to the target (equating to 24.6 million LGCs). Based on historical output in South Australia, wind capacity of 8,500 MW is required to generate this amount of electrical energy for the year.

Table 2-6 — Forecast LGC deficit

Year	2016	2017	2018	2019	2020 to 2030
Forecast LGC deficit (GWh, non-cumulative)	8,200	15,400	20,000	24,600	31,200
Equivalent wind generation capacity required to supply LGC deficit (cumulative, based on South Australian output) (MW)	2,800	5,300	6,900	8,500	10,800

2.3.4 Spot market price trends

Table 2-7 lists the average regional electricity spot market prices for the last 11 financial years. These prices are an important indicator of the viability of investment in new base load generation.

Table 2-7 — Average regional spot market prices ($/MWh)

Year	Queensland	New South Wales	Victoria	South Australia	Tasmania
2001–02	35	35	31	32	-
2002–03	38	33	28	30	-
2003–04	28	32	25	35	-
2004–05	29	39	28	36	-
2005–06	28	37	32	38	57
2006–07	52	59	55	52	50
2007–08	52	42	47	74	55
2008–09	34	39	42	51	58
2009–10	33	44	36	55	29
2010–11	31	37	27	33	29
2011–12	29	30	27	30	33

In general, average prices have been falling since 2006–07, with most regions seeing lower average prices in 2011–12 than any year since 2002–03. Severe drought conditions from 2007 to 2009 restricted the output of hydroelectric and coal-fired power stations, driving up prices in most regions. Some of the factors that have led to the relatively low average prices in 2010–11 and 2011–12 include the following:

- Mild summer temperatures in both years, with fewer and shorter high-price periods.[25]
- Reduced annual energy and increasing energy contributions from rooftop PV.
- The increasing capacity of connected wind farms, the lower operating costs of which put downwards pressure on spot prices.[26]

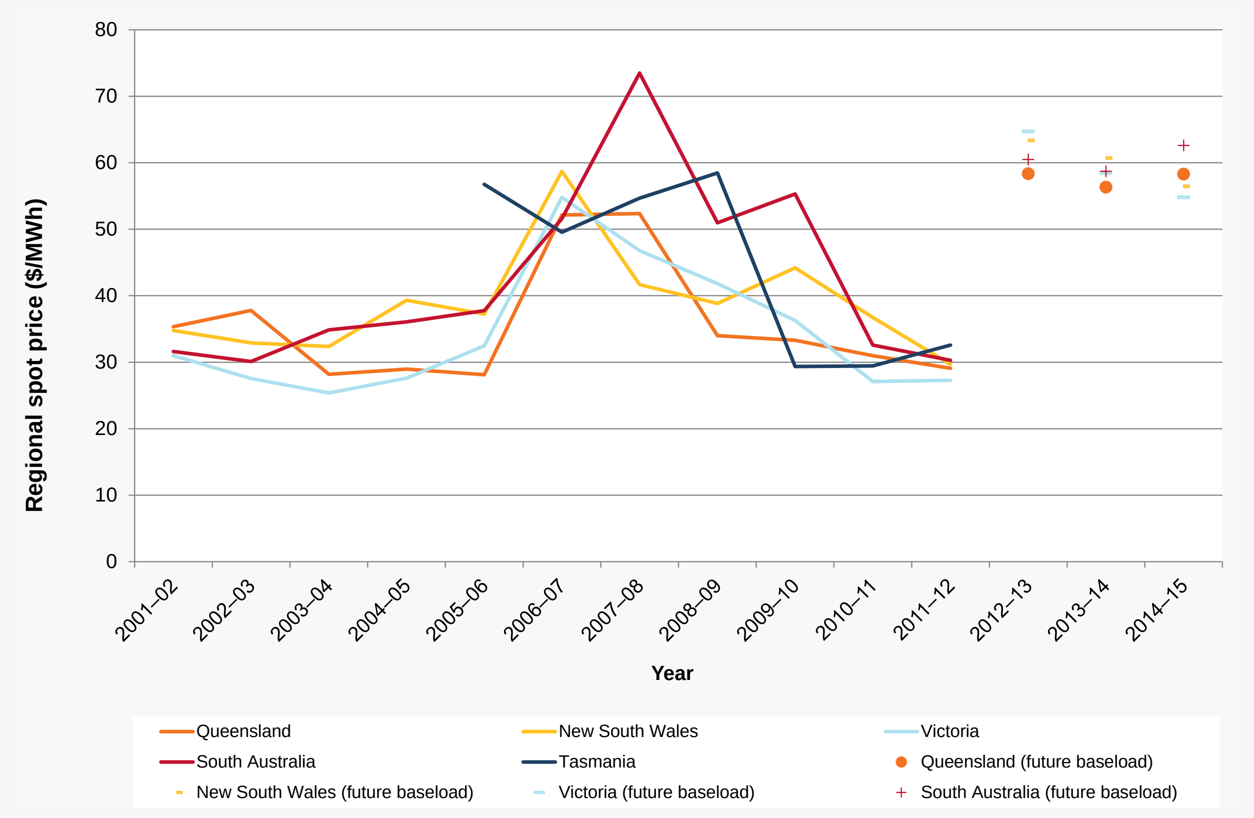
Figure 2-8 shows the average regional spot prices for the past 10 years, and prices for base load futures contracts for the next three financial years, as at 2 July 2012.[27]

Prices in 2011–12 are similar to the price levels from 2001–02 to 2005–06. The jump in the futures price in 2012-13 reflects the market's view of the impact of the carbon price, which came into effect on 1 July 2012.

The 2013 ESOO will include an analysis of the carbon price's impact on the spot market in its first year. For more detailed data and analysis of spot market prices, see the Historical Market Information page available from AEMO's website.[28]

[25] For more information about demand and temperatures during the 2011–12 summer, see: AEMO. "2011-12 NEM Demand Review". Available http://www.aemo.com.au/en/Electricity/Forecasting/2012-Information-Papers. Viewed 4 July 2012.
[26] Analysis by AEMO in the 2011 South Australian Supply Demand Outlook found that the South Australian spot price can become depressed at times of high wind output. Available http://www.aemo.com.au/en/Electricity/Planning/2011-South-Australian-Supply-Demand-Outlook. Viewed 4 July 2012.
[27] These prices are for bilateral base load generation futures contracts traded online through D-Cypha Trade. Such contracts specify the supply of electricity, set at a particular MW level and price in the future. No contracts are offered for Tasmania in the D-cypha Trade market. See D-cyphatrade. "Market Futures". Available http://d-cyphatrade.com.au/market_futures#A. Viewed 2 July 2012.
[28] AEMO. Available http://www.aemo.com.au/electricity/NEM-Data/Average-Price-Tables.aspx. Viewed 9 July 2012.

Figure 2-8 — Average regional spot market prices



2.3.5 Trends in NEM generation

This section summarises trends in the capacity and output of scheduled, semi-scheduled and significant non-scheduled generation included by AEMO in its assessment of operational demand.[29]

Figure 2-9 compares NEM generation capacities by fuel source in 2000 and 2012. Generation is largely provided by coal-fired technologies, but has diversified since 2000, with increases in the proportion of wind and natural gas.

[29] Including significant non-scheduled generation in operational demand means it is not treated as a demand offset by AEMO's market systems. For more information about scheduled, semi-scheduled, and non-scheduled generating system classification types, see Section 2.4.1.

Figure 2-9 — NEM generation capacity by fuel source, 2000 and 2012

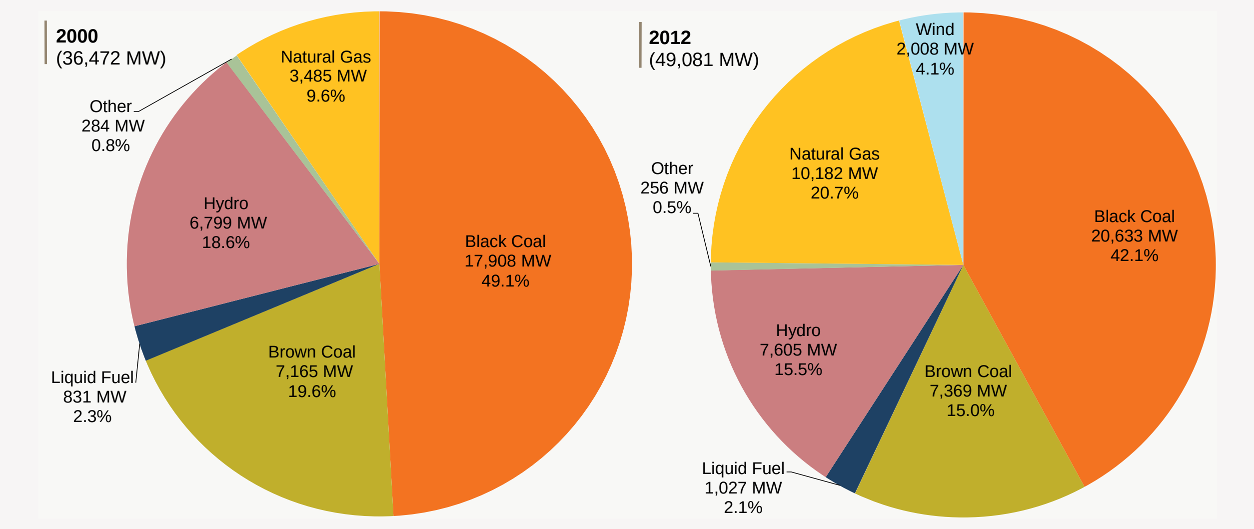


Figure 2-10 and Figure 2-11 show annual electricity generation by fuel type over the period 2006–07 to 2011–12.

The figures provide the following observations:

- Output from brown coal generation was relatively steady.
- Output from black coal generation peaked in 2007–08 at 121 TWh, and then declined at an average annual rate of 4%.
- Output from gas powered generation (GPG) increased by an average of 6% per year.
- Output from wind generation increased by an average of 37% per year.
- Output from hydroelectric generation fluctuated between a minimum of 12 TWh (in 2008–09) and 16 TWh (in 2010–11).

Figure 2-10 — Annual energy production from coal

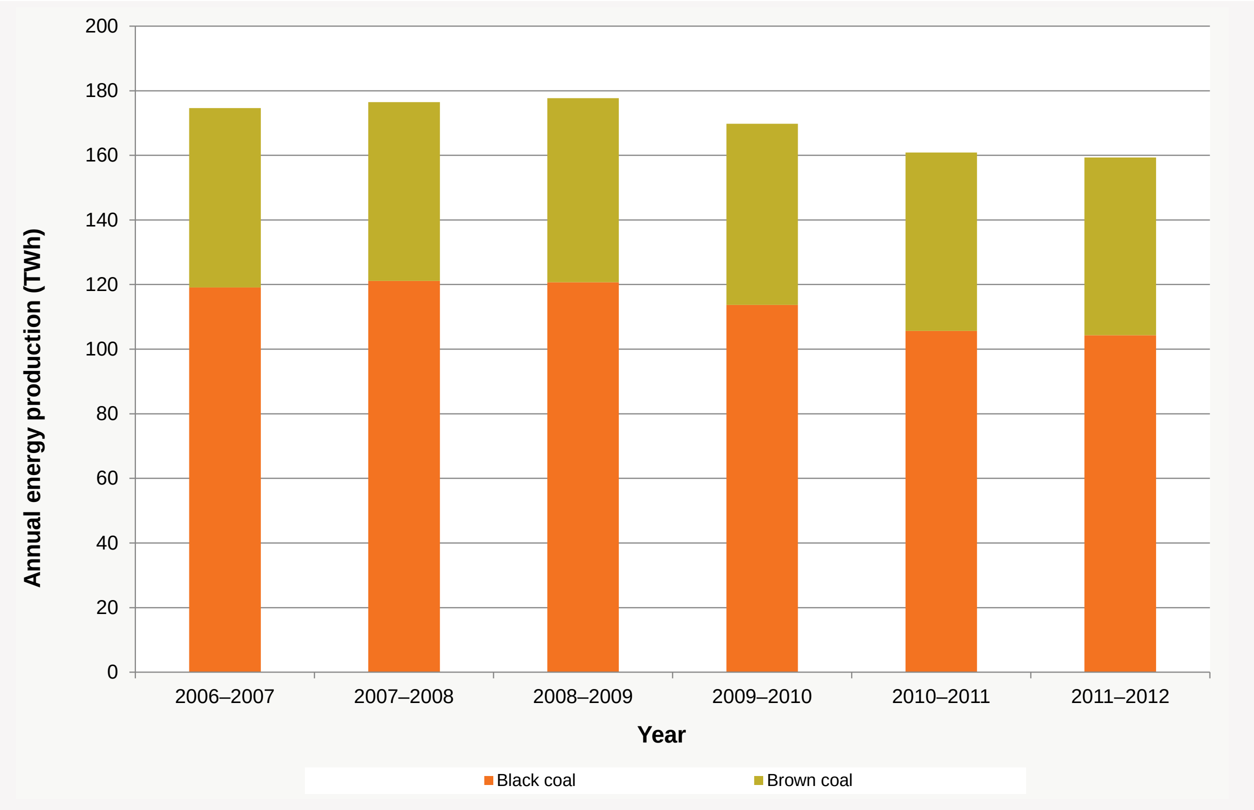
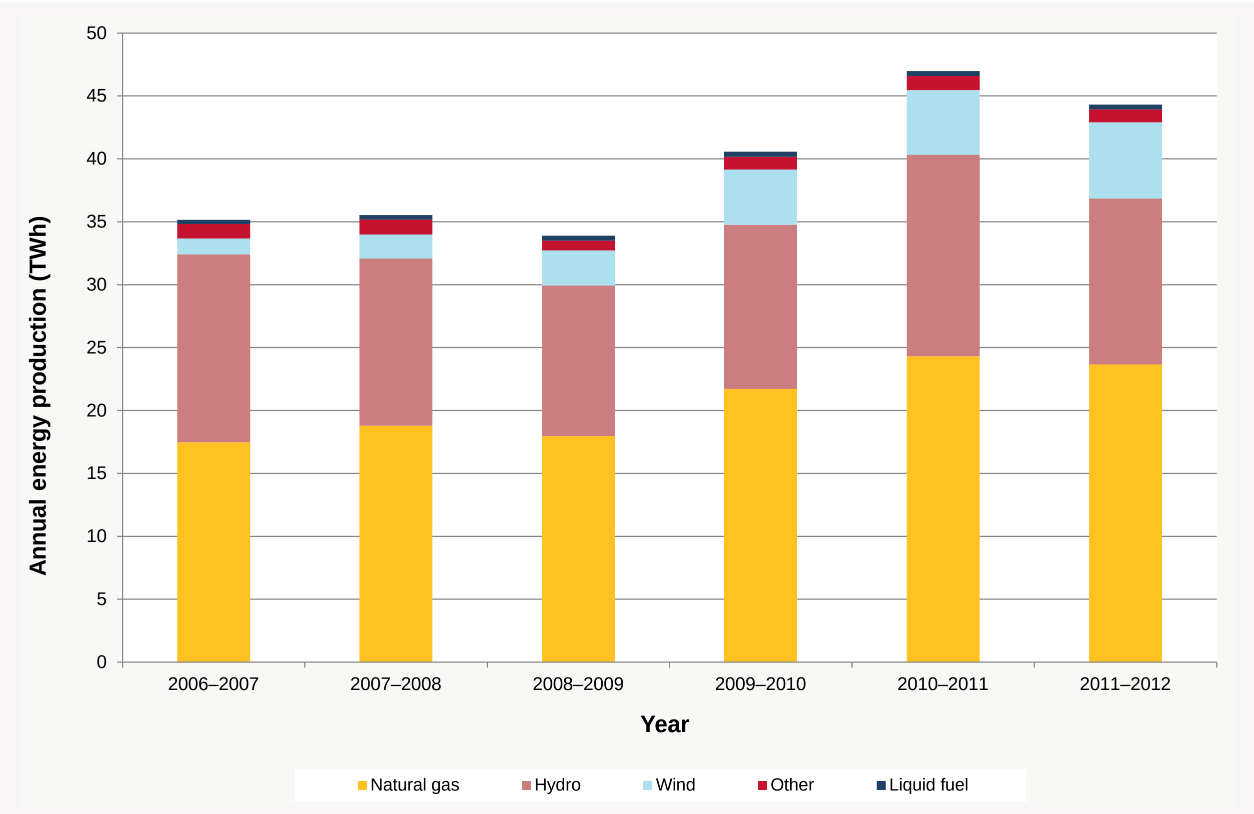


Figure 2-11 — Annual energy production by fuel source (excluding coal)



2.4 NEM generation capacity update

2.4.1 Changes to generation capacity

This section summarises NEM generation capacity changes since the 2011 ESOO. An update of the total available capacities for the upcoming summer and winter periods is also provided. For more detailed generation capacity information for each NEM region, see AEMO's Generation Information webpage.[30]

The information in this section is based on the capacity of registered generators. Under the National Electricity Rules (NER), registered generating systems are classified as scheduled, semi-scheduled, or non-scheduled.

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 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 information.

Non-scheduled generation refers to generating systems with an aggregate nameplate capacity of less than 30 MW, unless classification is approved by AEMO as a scheduled or semi-scheduled generating system.[31]

Projects completed since 2011

Since 2011 there have been increases in generation capacity in New South Wales, Victoria and South Australia. Table 2-8 lists the commissioned power stations since 2011, and Table 2-9 summarises the completed upgrades to existing power stations.

Table 2-8 — Power stations commissioned since 2011

Region	Registered participant	Power station	Capacity (MW)	Fuel/technology	Commissioning date
Victoria	Oaklands Hill Wind Farm Pty Ltd.	Oaklands Hill.	67	Wind.	February 12.
	Origin Energy Power Limited.	Mortlake Stage 1.	566	Gas/open-cycle gas turbine (OCGT).	July 11.
South Australia	Eurus Energy.	Hallet 5 (The Bluff).	53	Wind.	December 11.

Table 2-9 — Power station upgrades completed since 2011

Region	Registered participant	Power station	Capacity (MW)	Fuel/technology	Commissioning date
New South Wales	Eraring Energy.	Eraring - upgrade (Unit 1).	60	Steam turbine/black coal.	2012.

[30] AEMO. Available http://www.aemo.com.au/en/Electricity/Planning/Related-Information/Generation-Information. Viewed 4 July 2012.
[31] Most non-scheduled generating systems have an aggregate nameplate capacity between 5 MW and 30 MW. For more information about this classification, see Chapter 2 of the NER.

Generator retirements and changes to available capacity

AEMO has been advised by existing generators of several recent retirements, and predicted changes to generation capacity over the next 10 years. Table 2-10 lists the retirements that have been included in the supply-demand outlook.[32]

Table 2-10 — Recent and planned generator retirements

Region	Generating unit(s)	Capacity (MW)	Fuel type	Planned retirement date
Queensland	Mackay Gas Turbine.	34	Natural gas.	December 2016.
	Swanbank B Power Station Unit 3.	125	Black coal.	May 2012.
New South Wales	Munmorah Power Station.	600	Black coal.	July 2012.

In Victoria, Energy Brix has advised that Unit 5 of the Morwell Power Station (75 MW) has been taken out of normal service and will only be available following a recall period. Based on this advice, this unit has not been included in the generation capacity for the supply-demand calculator or the list of scheduled and semi-scheduled generation capacities that are available from AEMO's generator information page.

Alinta Energy advises of changes to the availability of Playford B Power Station (240 MW) and Northern Power Station (530 MW) in South Australia:

- Playford B Power Station plans to only be available during summer and winter after an extended recall period.

  Based on this advice, the supply-demand calculator has not included Playford B's generation capacity. This generator is still included with the list of scheduled and semi-scheduled generation capacities that are available from AEMO's generator information page.
- Northern Power Station plans to continue normal summer operation, but will only be available after an extended recall period, from 1 April to 30 September in 2013 and 2014. After 1 October 2014, the power station will return to normal service.

  Based on this advice, the supply-demand calculator has not included Northern Power Station's generation capacity during winter 2013 or 2014. This generator is still included with the list of scheduled and semi-scheduled generation capacities, available from AEMO's generator information page.

Committed project developments

Committed generation projects are included in the supply-demand calculator from their expected date of commissioning. AEMO classifies a new project as committed if it satisfies all of the following criteria:

- All land has been acquired.
- Contracts for supply of major components are finalised.
- All planning and environmental approvals have been obtained.
- Financing arrangements are finalised.
- Project construction has commenced or a date for commencing construction has been set.

[32] A generator's operational plans are subject to change and may diverge from the information provided in AEMO's annual generator survey. AEMO assesses these changes as they arise and incorporates them into the appropriate assessments of system adequacy, including the Medium-term Projected Assessment of System Adequacy (MT PASA), the Power System Adequacy (PSA) report, and the ESOO's supply-demand outlook.

By March 2012, there were five committed projects in the NEM:

- Macarthur Wind Farm is a 420 MW development by the Macarthur Wind Farm Pty Ltd, involving AGL Energy and Meridian Energy in Victoria. This project has commenced construction, with commissioning planned for January 2013.
- Musselroe Wind Farm is a 168 MW development by Hydro Tasmania. Construction at the site has commenced and commissioning is planned for June 2013.
- Qenos Cogeneration Facility is a 21 MW GPG power station in Victoria that will provide heat and power to the Qenos plastics facility in Altona. Commissioning is expected in October 2012. The generator will be registered as non-scheduled, and will export its excess power to the grid. Because this generator will be non-scheduled, the supply-demand outlook will include its output as a demand reduction (or offset).
- Morton's Lane Wind Farm is a 20 MW development by Morton's Lane Wind Farm Pty. Ltd. (a joint venture between Goldwind and NewEn) in Victoria. This project has commenced construction and commissioning is planned for the second half of 2012. This generator will be non-scheduled, and the supply-demand outlook will include its output as a demand reduction (or offset).
- A further 60 MW upgrade to the Eraring Power Station in New South Wales is to be completed by October 2012.

2.4.2 Current investment interest

Each year AEMO surveys registered market participants and other project developers believed to be developing future generation projects, for information about current investment interest in the NEM. This section summarises the results of the latest survey, which was conducted in March 2012.

For more information relevant to each region, see Chapter 3. For information about individual projects, see the AEMO website's Generation Information section.[33]

AEMO classifies new generation projects as either committed or proposed (for information about currently committed projects and the criteria used to assess a project's committed status, see Section 2.4.1).

This section focuses on proposed projects, which are in earlier stages of development and have not satisfied all of the commitment criteria, and are classified in one of two ways:

- Advanced proposals represent generation at an intermediate stage of development that has satisfied three of the five commitment criteria.
- Publicly announced proposals represent generation at an early stage of development that has satisfied less than three commitment criteria.

A project that has been publicly announced at some stage may be removed from the list of proposals at a later time. These projects are classified as inactive or unlikely to proceed as a result of several factors:

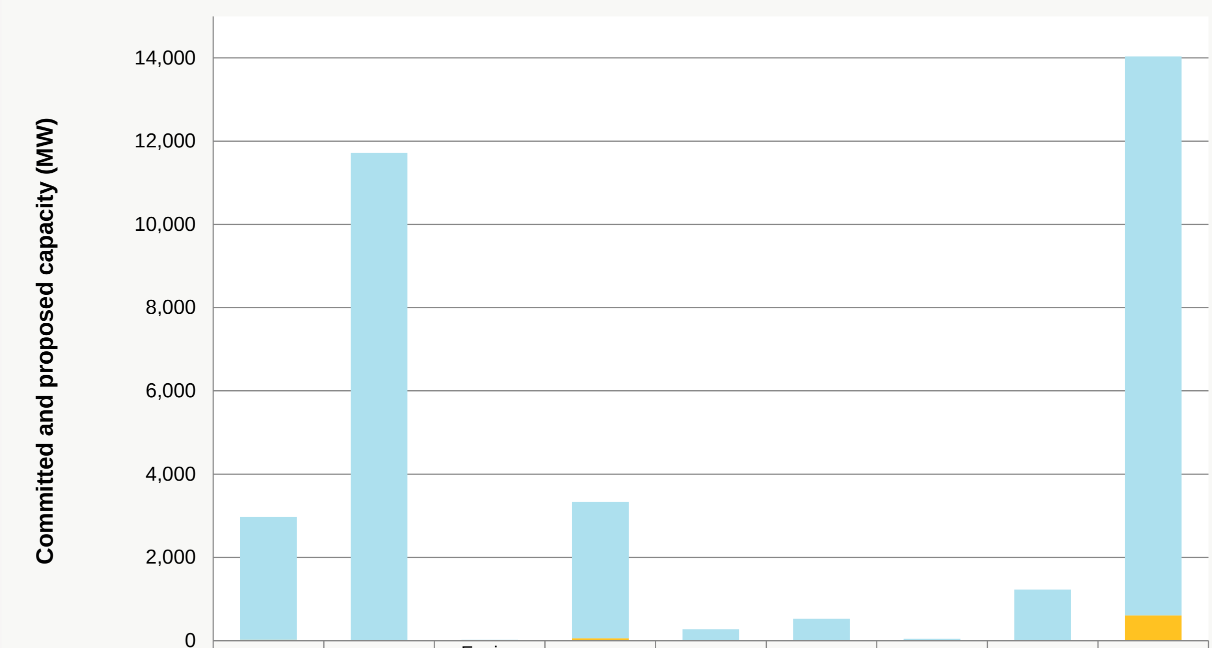
- The project proponent advising AEMO of the change in a project's status.
- AEMO is unable to contact the proponent for updated information.
- AEMO has obtained information from other publicly available sources that indicate the project is no longer likely to proceed.

Figure 2-12 shows the current commitment status of public generation developments in the NEM. Apart from the committed projects described in Section 2.4.1, only the 3 MW upgrade of the Tungatinah hydroelectric plant in Tasmania (reported as publicly announced in the 2011 ESOO) has progressed to an advanced classification in 2012.

[33] See note 30.

Current investment interest is focussed on renewable and peaking generation, with publicly announced proposals involving over 13,000 MW of wind generation capacity and over 11,000 MW of open-cycle gas turbine (OCGT) generation capacity. There is less interest in base load generation investment, with publicly announced proposals involving approximately 3,300 MW of black coal generation capacity, and approximately 3,000 MW of combined-cycle gas turbine (CCGT) generation capacity.

Figure 2-12 — Current commitment status of public generation developments in the NEM



	CCGT	OCGT	Engine (gas-fuelled)	Black coal	Biomass	Geothermal	Hydro	Solar	Wind
Publicly announced	2,950	11,720	17	3,270	273	525	40	1,228	13,427
Advanced							3		
Committed	21			60					608

Gas powered generation

GPG developments represent the highest capacity of total investment interest, with major projects proposed in all regions except Tasmania. Publicly announced proposals include 11,720 MW of OCGT generation, 2,950 MW of CCGT generation, and 17 MW of compression reciprocating engine generation, fuelled by natural gas (13,090 MW), coal seam gas (1,595 MW), and landfill gas (2 MW), respectively.

Most of the new proposed projects announced since 2011 involve OCGT generation capacity in Queensland. These include the Blackstone Power Station (1,500 MW), Aldoga Power Station (1,500 MW), and Braemar 4 (495 MW). There is also a new proposed project involving 600 MW of OCGT generation (the Bannaby Power Station) in New South Wales.

Other large publicly announced proposals involving OCGT generation include the Westlink Power Project in Queensland (1,000 MW), the Kerraway Gas Turbine in New South Wales (1,000 MW), and Marulan in New South Wales (700 MW).

The four publicly announced proposals involving CCGT technology include Spring Gully in Queensland (1,000 MW), Tallawarra B in New South Wales (450 MW), and Yallourn (1,000 MW) and the Shaw River Power Station (500 MW) in Victoria.

Wind generation

The scope and size of proposed wind farms has changed significantly over the past 12 months, with a total reduction of approximately 2,200 MW in the capacity of publicly announced proposals (excluding the few proposed projects that are now committed).

Eighteen publicly announced proposals from the 2011 ESOO are no longer included, as project proponents have advised AEMO they are no longer active. This involves 14 proposals in Victoria, including the Baynton (240 MW) Wind Farm, the Sidonia Hills Wind Farm (80 MW), and the Mortlake East Wind Farm (75 MW).

There are ten new publicly announced proposals, including 1,014 MW in South Australia, 825 MW in Queensland, 90 MW in Tasmania, and 85 MW in New South Wales.

No new publicly announced proposals involving wind farms have been announced in Victoria.

Solar photovoltaics

There are currently no registered solar power plants in the NEM. However, interest in the development of large-scale solar PV power plants has increased significantly in recent years, with combined interest in solar thermal and large-scale solar PV capacity totalling 1,228 MW. This increase in interest has been largely driven by the Australian Government's Solar Flagships Program, which began in 2009 to support the construction of large-scale grid-connected solar thermal and solar PV power stations.[34]

Large-scale solar PV funding under this program changed in 2012, requiring the four previously shortlisted project developers to re-submit funding proposals. The successful proposal involves the Nyngan Solar Farm (106 MW) and the Broken Hill Solar Farm (53 MW).

The successful solar thermal project under the program was the 250 MW Solar Dawn proposal in Queensland.

Black coal and coal gasification

Macquarie Generation's publicly announced proposal for the 2,000 MW Bayswater B Power Station in New South Wales is the largest coal-fired generation proposal for 2012. There is also a publicly announced proposal from Delta Electricity for a 700 MW rehabilitation of the black coal-fired Munmorah Power Station in New South Wales.

Two publicly announced proposals in 2011 involving coal gasification are no longer included as they are now classified as inactive or unlikely to proceed. This includes the 550 MW HRL Developments Dual Gas Demonstration Project in Victoria, involving brown coal and integrated drying and gasification combined-cycle (IDGCC) technology, and the 504 MW Stanwell Corporation integrated black coal gasification combined-cycle power station near Wandoan in Queensland.

[34] Department of Resources, Energy and Tourism. "Solar Flagships Program". Available http://www.ret.gov.au/energy/clean/sfp/Pages/sfp.aspx. Viewed 4 July 2012.

2.5 Links to supporting information

This section provides links to documents and web pages with supporting information about the national investment outlook.

Information source	Website address
Supply-Demand Calculator and Tutorials	http://www.aemo.com.au/Electricity/Planning/Electricity-Statement-of-Opportunities/Supply-Demand-Calculator-and-Tutorials
National Energy Forecasting Report	http://www.aemo.com.au/en/Electricity/Forecasting/2012-National-Electricity-Forecasting-Report
Generator Information Page	http://www.aemo.com.au/Electricity/NEM-Data/Generation-Information
Historical Market Information Page	http://www.aemo.com.au/Electricity/Planning/Related-Information/Historical-Market-Information
2012 Power System Adequacy – Two Year Outlook	http://www.aemo.com.au/Electricity/Market-and-Power-Systems/Power-System-Adequacy-Two-Year-Outlook
Economic Outlook Information Paper	http://www.aemo.com.au/en/Electricity/Forecasting/2012-Information-Papers
Rooftop PV Information Paper	http://www.aemo.com.au/en/Electricity/Forecasting/2012-Information-Papers
2011-12 NEM Demand Review Information Paper	http://www.aemo.com.au/en/Electricity/Forecasting/2012-Information-Papers
Energy Adequacy Assessment Projection (EAAP)	http://www.aemo.com.au/en/Electricity/Market-and-Power-Systems/Energy-Adequacy-Assessment-Projection
Wind Contribution to Peak Demand	http://www.aemo.com.au/en/Electricity/Planning/Related-Information/Wind-Contribution-to-Peak-Demand

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CHAPTER 3 - REGIONAL INVESTMENT OUTLOOK

Summary

This chapter provides information about the individual investment outlooks for each NEM region over the 10-year outlook period (2012–13 to 2021–22). This includes the regional supply-demand outlooks, AEMO's latest annual energy projections under the low, medium, and high scenarios[1], and maximum demand projections under the medium scenario.

Summer and winter aggregate scheduled and semi-scheduled generation capacities are also included, as well as a summary of current generation investment interest.

Section 3.1 describes how to interpret the information presented in each region's supply-demand outlook, including the low reserve condition (LRC) points, which indicate the timing of a projected reserve deficit in a particular region.[2]

For links to supporting information relevant to this chapter (published separately), see Section 3.7.

Queensland

The medium scenario annual energy projection averages annual growth of 2.9%, and the 10% probability of exceedence (POE)[3] maximum demand projection averages annual growth of 2.5% (or approximately 257 MW). The LRC point is projected to occur in 2020–21, with a shortfall of 79 MW. Changes to the projected generation capacity include retirement of Swanbank B Power Station Unit 3 in May 2012, and the planned retirement of the Mackay Gas Turbine at the end of 2016. There are no new committed projects.

New South Wales

The medium scenario annual energy projection averages annual growth of 1.2%, and the 10% POE maximum demand projection averages annual growth of 1.2% (or approximately 175 MW). No LRC point is projected to occur in the outlook period. Changes to the projected generation capacity include retirement of Munmorah Power Station in July 2012 and a committed project to upgrade the Eraring Power Station by 60 MW.

Victoria

The medium scenario annual energy projection averages annual growth of 1.4%, and the 10% POE maximum demand projection averages annual growth of 1.6% (or approximately 185 MW). The LRC point is projected to occur in 2018–19, with a shortfall of 115 MW. Changes to the projected generation capacity include Morwell Power Station Unit 3 being removed from normal service in July 2012, two committed wind generation projects, with a combined capacity of 440 MW, and a further committed gas cogeneration project with a capacity of 21 MW.

South Australia

The medium scenario annual energy projection averages annual growth of 0.9%, and the 10% POE maximum demand projection averages annual growth of 1.0% (or approximately 34 MW). The LRC point is projected to occur in 2019–20, with a shortfall of 24 MW. Changes to the projected generation capacity include the availability of the Northern and Playford B Power Stations. There are no new committed projects.

Tasmania

The medium scenario annual energy projection averages annual growth of 0.9%, and the 10% POE maximum demand[4] projection averages annual growth of 1.1% (or approximately 21 MW). No LRC point is projected to occur in the outlook period. Changes to the projected generation capacity include a committed wind generation project in Tasmania with a capacity of 168 MW.

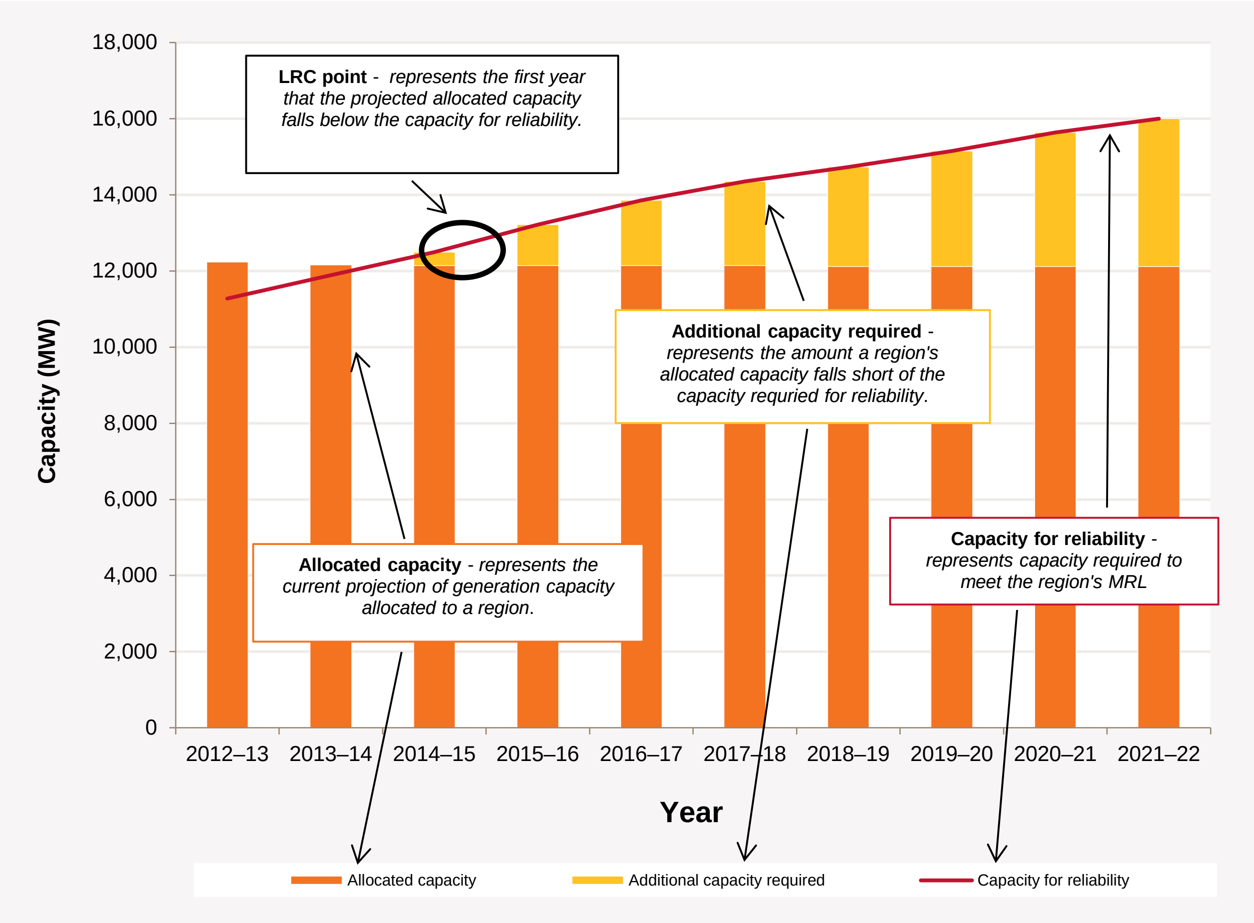
[1] For more information about the scenarios, see Chapter 1, Section 1.4.
[2] For more information about the calculation of the supply-demand outlook, including reliability and reserve-sharing, see Chapter 2, Section 2.2.
[3] A POE refers to the likelihood that a projection will be met or exceeded in a given year.
[4] The maximum demand in Tasmania occurs during the winter.

3.1 Interpreting the supply-demand outlook

Each region's summer or winter supply-demand outlook is presented as a graph of supply adequacy trends. This graph summarises the results of the supply-demand calculator, showing the timing of LRC points and the magnitude of projected reserve deficits over the outlook period. Additional background information about the methodology and inputs to the supply-demand calculator is available in Chapter 2, Section 2.2, and from the 2012 ESOO supplementary information section.[5]

Figure 3-1 provides a guide to interpreting the outlooks.

Figure 3-1 — Interpreting the supply-demand outlook



3.2 Investment outlook in Queensland

3.2.1 Supply-demand outlook

Figure 3-2 shows the projected Queensland summer supply-demand outlook for 2012–13 to 2021–22.

The figure indicates that under the medium scenario, Queensland reaches the LRC point in 2020–21, requiring 79 MW of new generation or demand-side investment to delay the shortfall until the following year, compared to the

[5] AEMO. "2012 Supply-Demand Calculator and Tutorials". Available http://www.aemo.com.au/Electricity/Planning/Electricity-Statement-of-Opportunities/Supply-Demand-Calculator-and-Tutorials. Viewed 9 August 2012.

2011 ESOO's projected LRC point in 2013–14. This change in timing is mainly due to the reduced maximum demand projections since 2011.

Figure 3-2 — Queensland summer supply-demand outlook

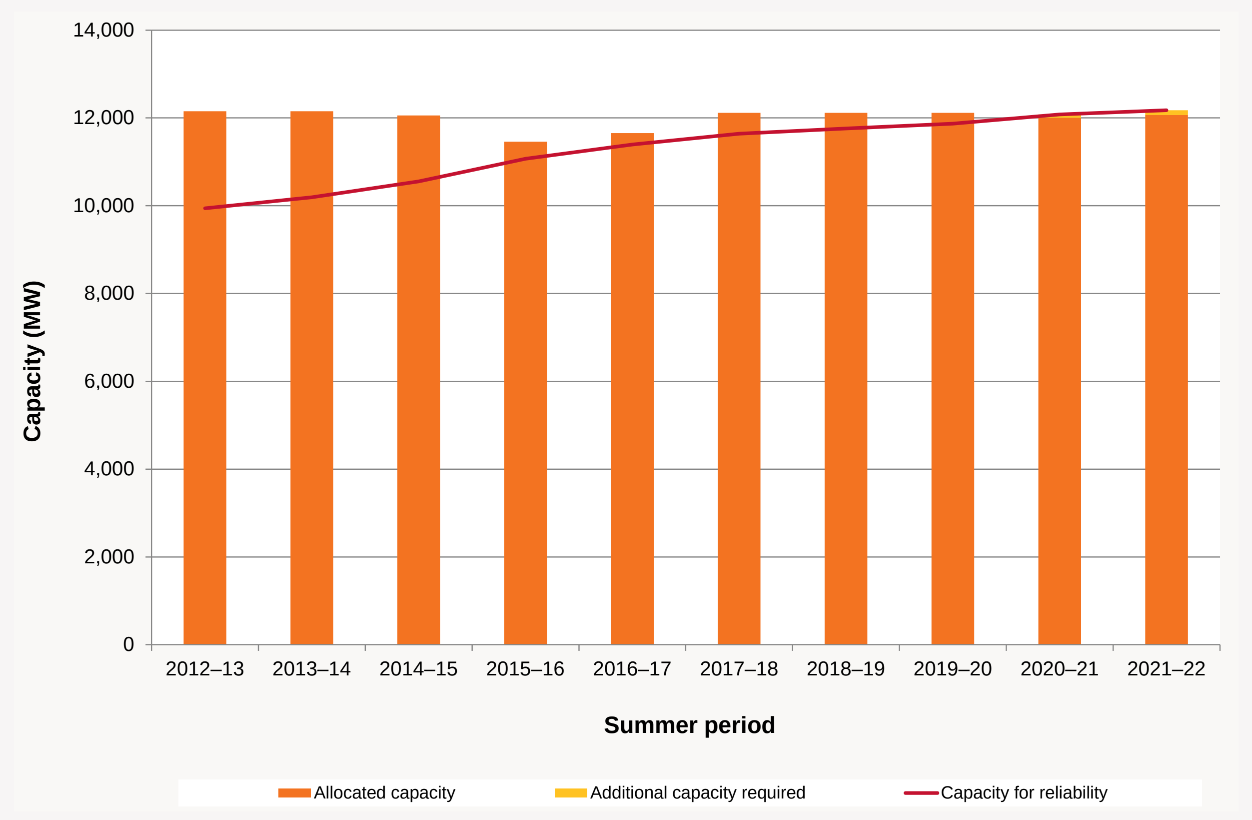


Table 3-1 shows the LRC point and reserve deficit projections for the low, medium and high scenario. The LRC point is projected to occur under the medium scenario in summer 2020–21, and four years earlier under the high scenario in summer 2016–17. There is no LRC point under the low scenario.

Table 3-1 — Queensland supply-demand outlook summary

Region	Low scenario		Medium scenario		High scenario	
	LRC point	Reserve deficit (MW)	LRC point	Reserve deficit (MW)	LRC point	Reserve deficit (MW)
Queensland (summer)	>2021–22	-	2020–21	79	2016–17	93
Queensland (winter)	>2022	-	>2022	-	2019	36

3.2.2 Annual energy and maximum demand

Figure 3-3 shows the annual energy projection for Queensland under the low, medium and high scenario. Under the medium scenario, the average annual growth in energy over the outlook period is 2.9%.

Figure 3-3 — Queensland annual energy projections

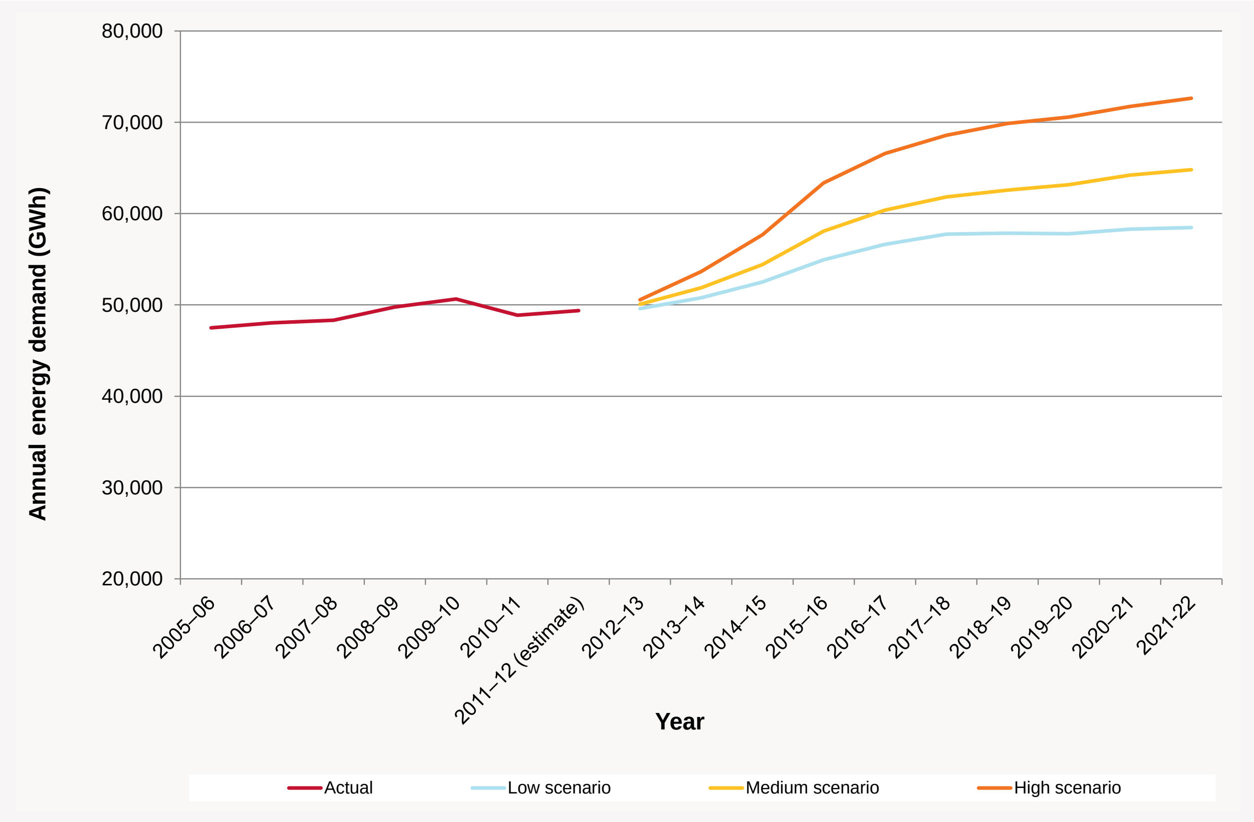
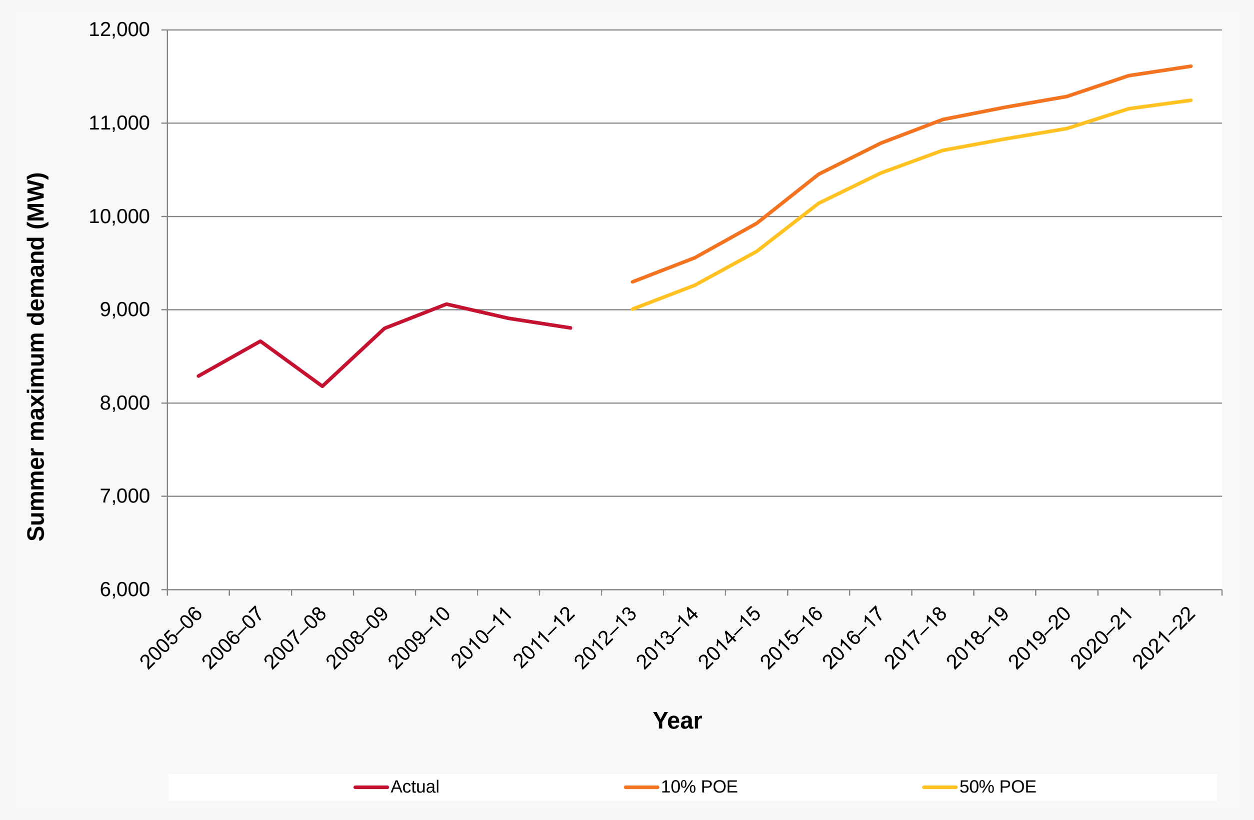


Figure 3-4 shows the medium scenario's summer 10% and 50% POE maximum demand projection for Queensland. The projected summer 10% POE maximum demand for 2012–13 is 9,299 MW, a reduction of 1,908 MW (17%) from 2011, and is projected to grow at an average annual rate of 2.5%, or approximately 257 MW.

Figure 3-4 — Queensland summer maximum demand projections (medium scenario)



3.2.3 Generation

This section summarises existing and committed generation capacities, and proposed generation projects in Queensland. For more detailed information about existing generation and proposed projects, see the AEMO website's Generation Information section.[6]

Table 3-2 and Table 3-3 list forecasts of summer and winter generation capacity in Queensland for the outlook period:

- The first row lists the sum of scheduled and semi-scheduled generation capacity information provided by generators in 2012.[7]
- The second row lists assumed generation capacities available to meet the maximum demand, and used in the supply-demand outlook.

  In some regions, the sum of generation capacities and the assumed generation capacities available to meet the maximum demand are different, due to capacity limitations experienced by some generators at the time of the maximum demand.

  These totals are the same, however, because there are no generators of this type in Queensland.

[6] AEMO. Available http://www.aemo.com.au/en/Electricity/Planning/Related-Information/Generation-Information. Viewed 11 July 2012.
[7] Capacity for Yarwun Power Station (registered as non-scheduled) is also included as generation rather than as a demand offset in the supply-demand outlook, because of its impact on network limitations.

The capacities shown account for the following:

- The Stanwell Corporation's Swanbank B Power Station Unit 3 retired in May 2012. This is the final unit of four original 125 MW black coal-fired units at the power station, which have been retired in stages since April 2010.
- The Stanwell Corporation plans to retire the 34 MW Mackay Gas Turbine at the end of 2016.

Table 3-2 — Summer generation capacity forecast – Queensland (MW)

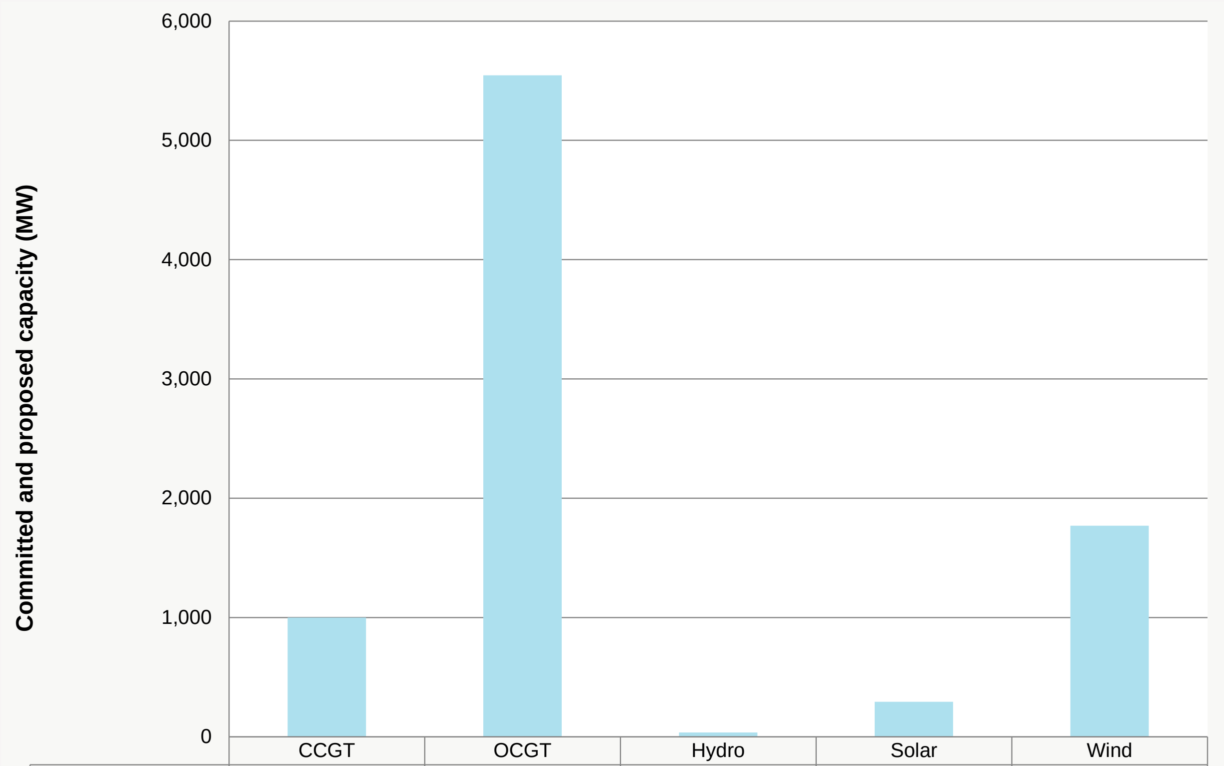
	2012–13	2013–14	2014–15	2015–16	2016–17	2017–18	2018–19	2019–20	2020–21	2021–22
Sum of summer generation capacities	12,209	12,209	12,209	12,208	12,208	12,173	12,173	12,173	12,173	12,173
Assumed generation capacity available for the maximum demand	12,209	12,209	12,209	12,208	12,208	12,173	12,173	12,173	12,173	12,173

Table 3-3 — Winter generation capacity forecast – Queensland (MW)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Sum of winter generation capacities	12,495	12,495	12,495	12,495	12,461	12,461	12,461	12,461	12,460	12,460
Assumed generation capacity available for the maximum demand	12,495	12,495	12,495	12,495	12,461	12,461	12,461	12,461	12,460	12,460

Figure 3-5 shows the generation investment interest in Queensland in March 2012. There are no committed projects or advanced proposals, however, there is significant interest in gas powered generation (GPG), with publicly announced proposals totalling 6,545 MW (including proposals of 1,045 MW using coal-seam gas as a primary fuel).

Figure 3-5 — Current commitment status of public generation developments in Queensland



	CCGT	OCGT	Hydro	Solar	Wind
Publicly announced	1,000	5,545	37	294	1,769

Investment interest in GPG and wind generation has increased since the 2011 ESOO, including the following new proposed projects, which are classified as publicly announced proposals:

- The Aldoga Power Station and Blackstone Power Station, each proposal involving 1,500 MW of open-cycle gas turbine (OCGT) capacity, being developed by TRUenergy.
- The Braemar 4 expansion by ERM Power, providing an additional 495 MW of OCGT capacity at the existing coal seam gas-fuelled Braemar Power Station. This is in addition to the 550 MW Braemar 3 project at the same site, which was announced in 2009 and is still a publicly announced proposal.
- The Kennedy Wind Farm, which is a 600 MW proposal by Wind Farm Developments.
- The Arriga Wind Farm, which is a 225 MW proposal by Ratch Australia.

There are no proposed projects involving black coal-fired generation in Queensland. The Wandoan 504 MW integrated black coal gasification combined-cycle gas turbine (CCGT) power plant is no longer included as a publicly announced proposal. Stanwell Corporation has advised AEMO that this project is now inactive.

There are two publicly announced proposals involving large-scale solar thermal generation, including the 250 MW Solar Dawn project, which was a successful candidate in the Australian Government's Solar Flagships Program.[8] The second proposal is the Kogan Creek Solar Boost Project, which aims to increase the capacity of the existing coal-fired Kogan Creek Power Station by 44 MW.

[8] Department of Resources, Energy and Tourism. "Solar Flagships Program". Available http://www.ret.gov.au/energy/clean/sfp/Pages/sfp.aspx. Viewed 4 July 2012.

3.3 Investment outlook in New South Wales

3.3.1 Supply-demand outlook

Figure 3-6 presents the projected New South Wales summer supply-demand outlook for 2012–13 to 2021–22.

The figure indicates that under the medium scenario, New South Wales does not experience an LRC point prior to 2021–22, compared to the 2011 ESOO's projected LRC point in 2018–19. This change in timing is mainly due to the reduced maximum demand projections since 2011.

Figure 3-6 — New South Wales summer supply-demand outlook

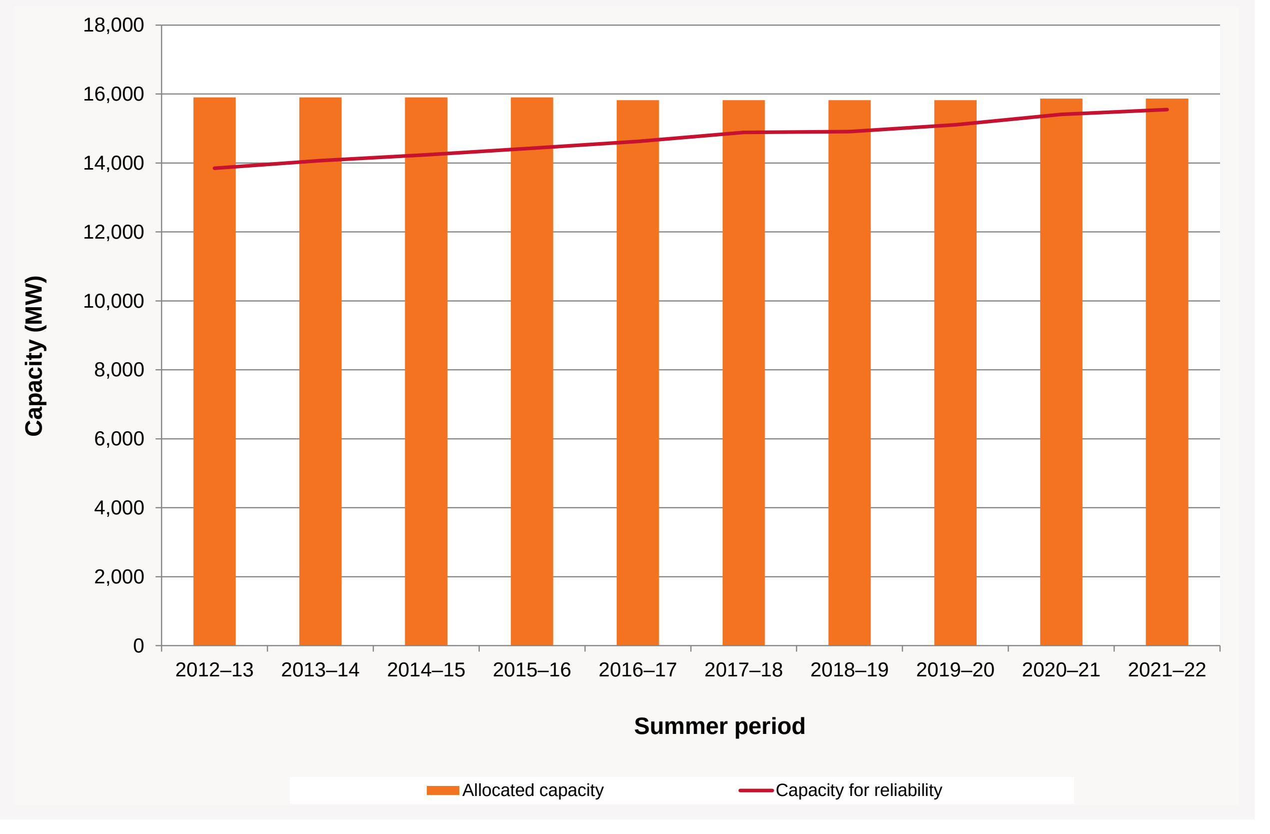


Table 3-4 shows the LRC point and reserve deficit projections for the low, medium and high scenario. New South Wales does not experience an LRC point prior to summer 2021–22 or winter 2022 under any of the scenarios.

Table 3-4 — New South Wales supply-demand outlook summary

Region	Low scenario		Medium scenario		High scenario	
	LRC point	Reserve deficit (MW)	LRC point	Reserve deficit (MW)	LRC point	Reserve deficit (MW)
New South Wales (summer)	>2021–22	-	>2021–22	-	>2021–22	-
New South Wales (winter)	>2022	-	>2022	-	>2022	-

3.3.2 Annual energy and maximum demand

Figure 3-7 shows the annual energy projection for New South Wales under the low, medium and high scenario. Under the medium scenario, the average annual growth in energy over the outlook period is 1.2%.

Figure 3-7 — New South Wales annual energy projections

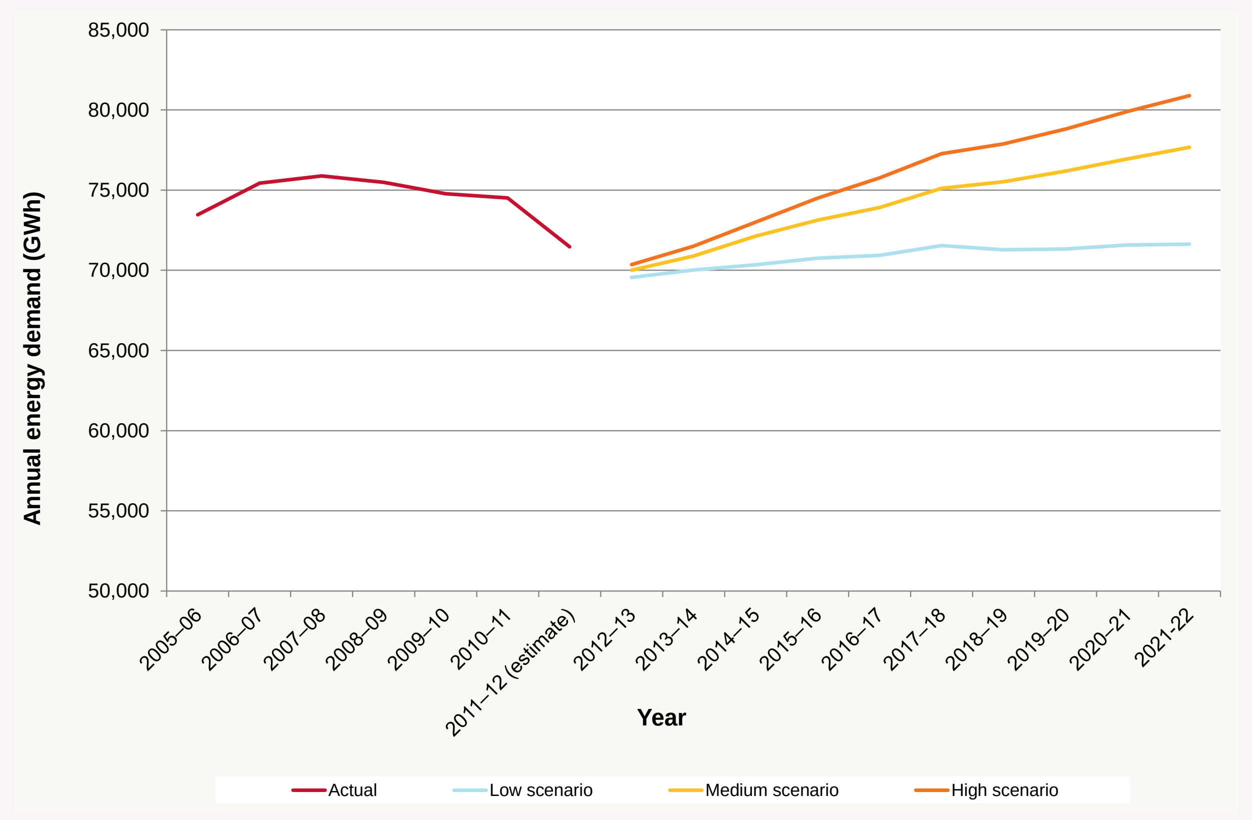
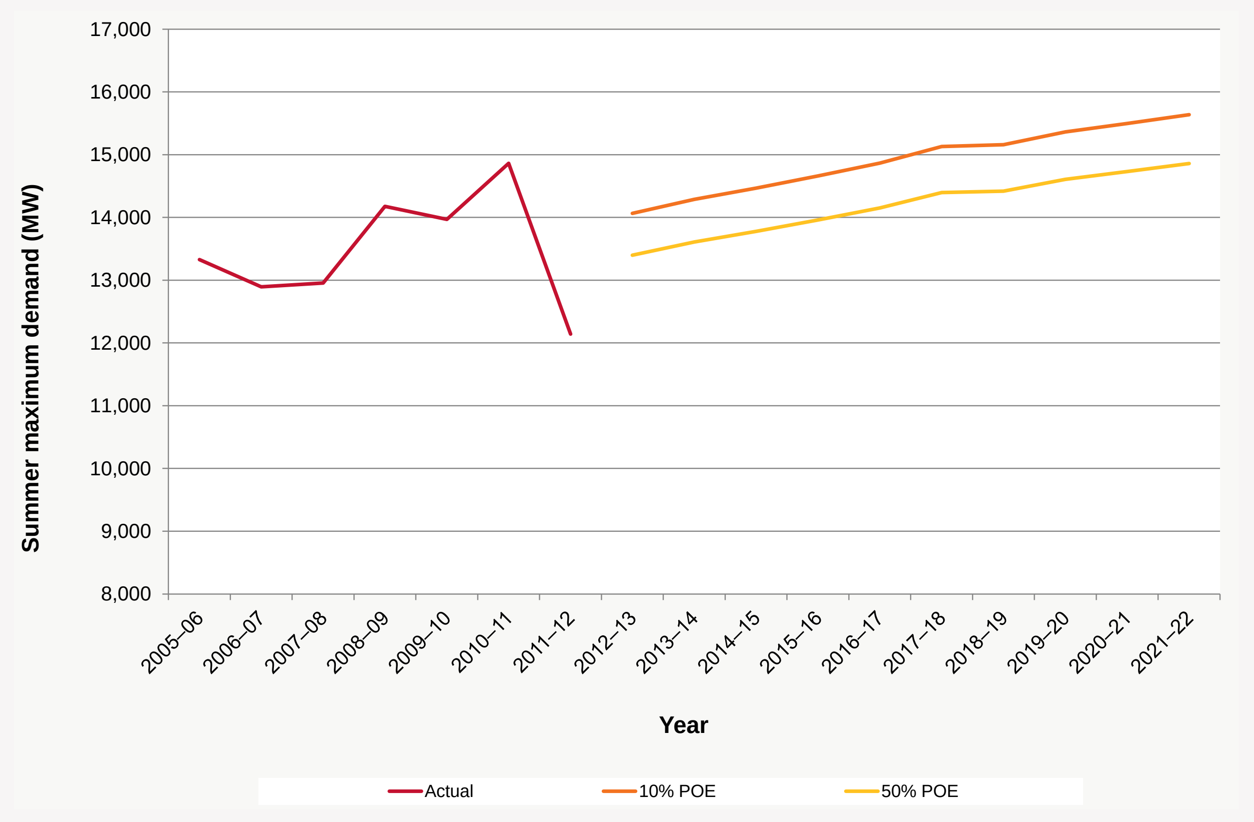


Figure 3-8 shows the medium scenario's summer 10% and 50% POE maximum demand projection for New South Wales. The projected summer 10% POE maximum demand for 2012–13 is 14,065 MW, a reduction of 2,056 MW (13%) from 2011, and is projected to grow at an average annual rate of 1.2%, or approximately 175 MW.

Figure 3-8 — New South Wales summer maximum demand projections (medium scenario)



3.3.3 Generation

This section summarises existing and committed generation capacities, and proposed generation projects in New South Wales. For more detailed information about existing generation and proposed projects, see the AEMO website's Generation Information section.[9]

Table 3-5 and Table 3-6 list forecasts of summer and winter generation capacity in New South Wales for the outlook period:

- The first row lists the sum of scheduled and semi-scheduled generation capacity information provided by generators in 2012.
- The second row lists assumed generation capacities available to meet the maximum demand, and used in the supply-demand outlook. A contribution factor of 2.2% for summer and 4.6% for winter is applied to the capacity of semi-scheduled wind farms.[10]

The capacities shown account for the following:

- The 600 MW Munmorah Power Station is retiring from July 2012.
- Completion of the committed Eraring Power Station 60 MW upgrade in October 2012.
- An 82 MW reduction in the summer capacity of the Upper Tumut Power Station from 2016–17 to 2019–20, and a 72 MW increase in its winter generation capacity from 2017 onwards, based on advice from Snowy Hydro.
- A 34 MW reduction in the summer capacity of Guthega Power Station for 2020–21 and 2021–22, based on advice from Snowy Hydro.

[9] See note 6.
[10] For a description of peak contribution factors for intermittent generation, see Chapter 2, Section 2.2.3.

Table 3-5 — Summer generation capacity forecast – New South Wales (MW)

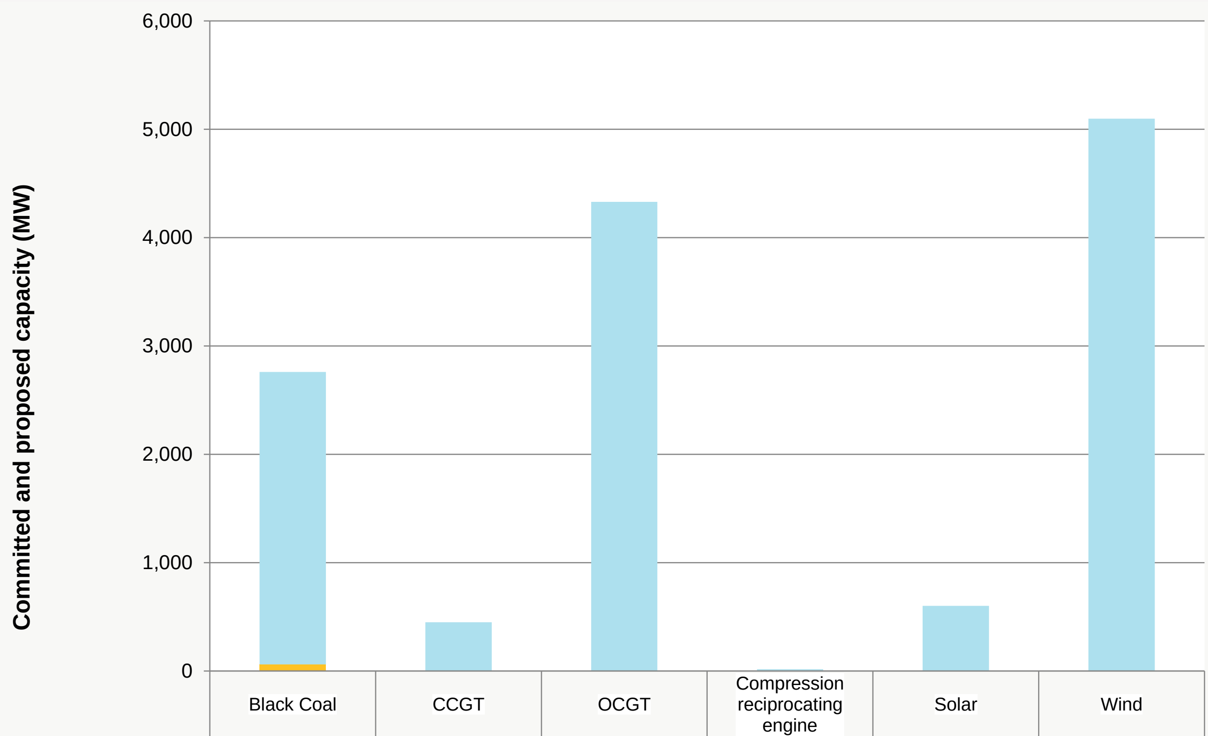
	2012–13	2013–14	2014–15	2015–16	2016–17	2017–18	2018–19	2019–20	2020–21	2021–22
Sum of summer generation capacities	16,327	16,327	16,327	16,327	16,245	16,245	16,245	16,245	16,293	16,293
Assumed generation capacity available for the maximum demand	16,234	16,234	16,234	16,234	16,152	16,152	16,152	16,152	16,200	16,200

Table 3-6 — Winter generation capacity forecast – New South Wales (MW)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Sum of winter generation capacities	16,388	16,388	16,388	16,388	16,460	16,460	16,460	16,460	16,460	16,460
Assumed generation capacity available for the maximum demand	16,297	16,297	16,297	16,297	16,369	16,369	16,369	16,369	16,369	16,369

Figure 3-9 shows generation investment interest in New South Wales in March 2012, including the committed upgrade of Eraring Power Station. Among the publicly announced proposals there is substantial investment interest in wind generation, natural gas-fuelled GPG, and black coal-fired generation.

Figure 3-9 — Current commitment status of public generation developments in New South Wales



	Black Coal	CCGT	OCGT	Compression reciprocating engine	Solar	Wind
Publicly announced	2,700	450	4,330	15	600	5,097
Committed	60					

There has been an increase in investment interest in GPG since the 2011 ESOO, including Bannaby Power Station (a new publicly announced proposal by Snowy Hydro) representing 600 MW of OCGT capacity. The publicly announced proposals for OCGT power stations have a total capacity of 4,330 MW, the largest of which is Origin Energy's 1,000 MW OCGT Kerraway Power Station. The only CCGT proposal in New South Wales is TRUenergy's publicly announced 450 MW Tallawarra B Power Station.

There are 28 publicly announced proposals involving wind generation totalling at least 5,097 MW, including four new proposals since the 2011 ESOO. Updated advice from project developers led to a decrease of approximately 1,500 MW in the total proposed capacity of wind farms since the 2011 ESOO. For more information, see the AEMO website's Generation Information section.[11]

The publicly announced proposals involving black coal include Macquarie Generation's 2,000 MW Bayswater B project and Delta Electricity's 700 MW Munmorah Rehabilitation project.

The Solar Flagships Program has driven interest in large-scale solar photovoltaic (PV) power plants in New South Wales. Large-scale solar PV funding under this program changed in 2012, requiring the four shortlisted project developers to re-submit funding proposals.[12] The proposal from AGL Energy and First Solar Australia was successful, involving the Nyngan Solar Farm (106 MW) and Broken Hill Solar Farm (53 MW).[13]

The proposals by Infigen Suntech Australia that did not receive funding but remain publicly announced include Capital Solar Farm (50 MW), Manildra Solar Farm (50 MW), and Nyngan Photovoltaic Solar Farm (100 MW). Infigen Energy also announced the Mildura Solar Farm in 2012, which is a new 180 MW publicly announced proposal located in New South Wales.

3.4 Investment outlook in Victoria

3.4.1 Supply-demand outlook

Figure 3-10 shows the projected Victorian summer supply-demand outlook for 2012–13 to 2021–22.

The figure indicates that under the medium scenario, Victoria reaches its LRC point in 2018–19, requiring at least 115 MW of new generation or demand-side investment to delay this shortfall until the following year, compared to the 2011 ESOO's projected LRC point in 2014–15. This change in timing is mainly due to the reduced maximum demand projections since 2011.

[11] See note 6.
[12] Department of Resources, Energy and Tourism. "Solar Flagships Program to Re-open Shortlist", Media Release (7 February 2012). Available http://minister.ret.gov.au/mediacentre/mediareleases/pages/solarflagshipsprogram.aspx. Viewed 4 July 2012.
[13] AGL Energy. "AGL to deliver large-scale solar PV projects under the Commonwealth Solar Flagships Program". Media Release (9 June 2012) Available http://www.agl.com.au/about/ASXandMedia/Pages/AGLtodeliverlargescalesolarPVprojectsundertheCommonwealthSolarFlagshipsProgram.aspx. Viewed 4 July 2012.

Figure 3-10 — Victorian summer supply-demand outlook

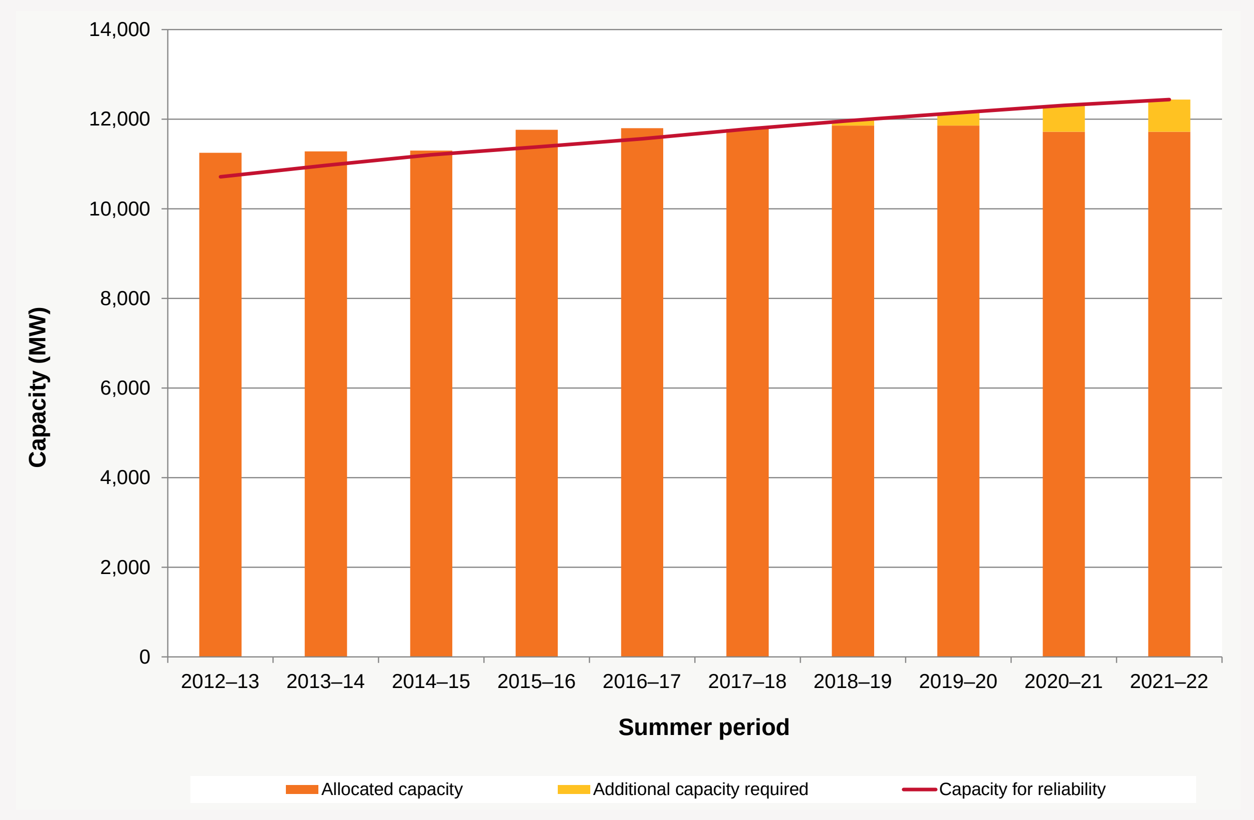


Table 3-7 shows the LRC point and reserve deficit projections for the low, medium and high scenario. The LRC point is projected to occur under the low scenario in 2021–22, the medium scenario in 2018–19, and the high scenario in 2015–16.

Table 3-7 — Victorian supply-demand outlook summary

Region	Low scenario		Medium scenario		High scenario	
	LRC point	Reserve deficit (MW)	LRC point	Reserve deficit (MW)	LRC point	Reserve deficit (MW)
Victoria (summer)	2021–22	54	2018–19	115	2015–16	50
Victoria (winter)	>2022	-	>2022	-	>2022	-

3.4.2 Annual energy and maximum demand

Figure 3-11 shows the annual energy projection for Victoria under the low, medium and high scenario. Under the medium scenario, the average annual growth in energy over the outlook period is 1.4%.

Figure 3-12 shows the medium scenario's summer 10% and 50% POE maximum demand projection for Victoria. The projected summer 10% POE maximum demand for 2012–13 is 10,624 MW, a reduction of 746 MW (7%) from 2011, and is projected to grow at an average annual rate of 1.6%, or approximately 185 MW.

Figure 3-11 — Victorian annual energy projections

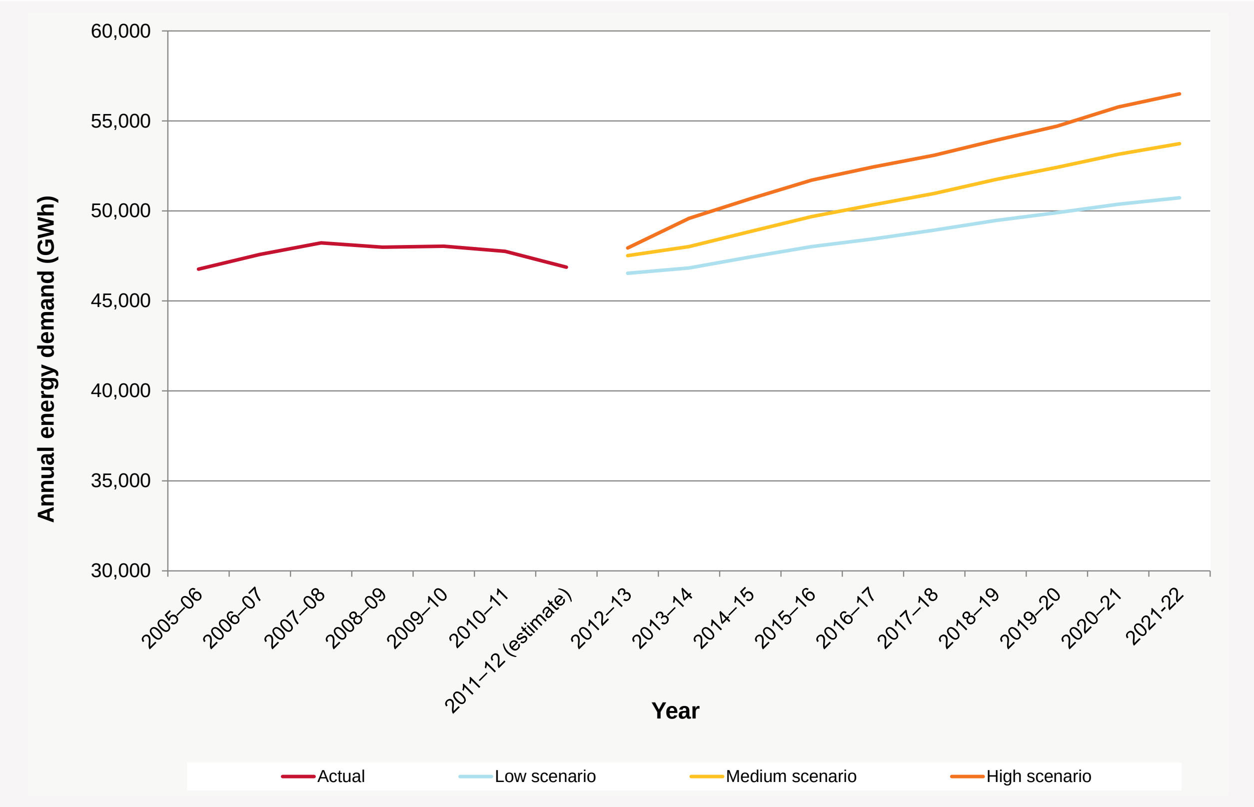
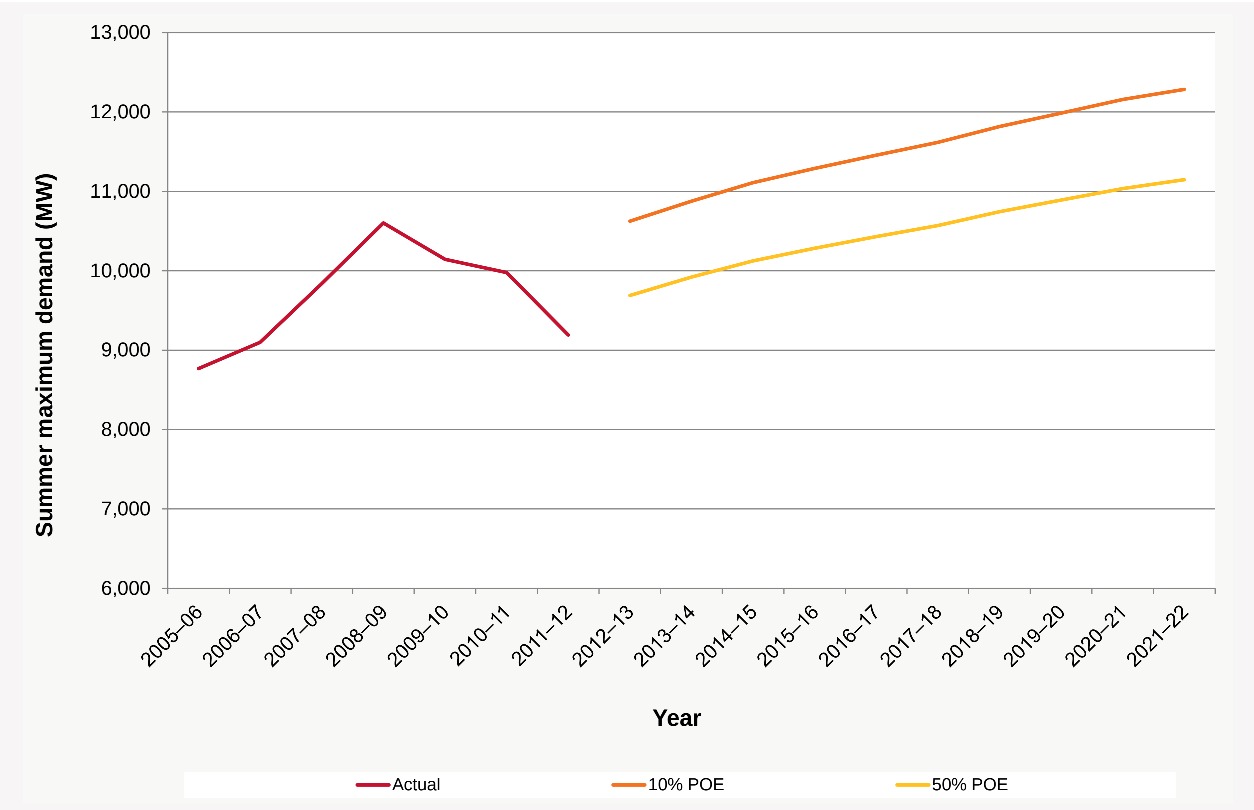


Figure 3-12 — Victorian summer maximum demand projections (medium scenario)



3.4.3 Generation

This section summarises existing and committed generation capacities, and proposed generation projects in Victoria. For more detailed information about existing generation and proposed projects, see the AEMO website's Generation Information section.[14]

Table 3-8 and Table 3-9 list forecasts of summer and winter generation capacity in Victoria for the outlook period:

- The first row lists the sum of scheduled and semi-scheduled generation capacity information provided by generators in 2012.[15]
- The second row lists assumed generation capacities available to meet the maximum demand, and used in the supply-demand outlook. A contribution factor of 6.5% for summer and 7.2% for winter is applied to the capacity of semi-scheduled wind farms.[16]

The capacities shown account for the following:

- Energy Brix has advised that Unit 5 of the Morwell Power Station (75 MW) has been taken out of normal service and will only be available following a recall period. Based on this advice, this unit is not included in the assumed generation capacity for supplying summer or winter maximum demand during the outlook period, or the sum of scheduled and semi-scheduled generation capacity.
- The committed Macarthur Wind Farm development by the Macarthur Wind Farm Pty Ltd (comprising AGL Energy and Meridian Energy), which represents 420 MW of new, semi-scheduled wind power capacity. This project has commenced construction and commissioning is planned for January 2013. Once completed, it will be the largest wind farm in the NEM, and has entered into energy and Large-scale Generation Certificate (LGC) supply contracts with the Wonthaggi Desalination Plant, which is currently under construction.
- Increases to the summer and winter capacity of the Dartmouth Power Station, from 130 MW in 2012–13 to 160 MW in 2013–14, 180 MW in 2014–15 and 185 MW from 2015–16 onwards, based on advice from AGL Energy.
- Changes involving a 95 MW decrease in the summer and winter capacity of the Murray 1 Power Station from 2014–15 to 2015–16, a 138 MW decrease in the capacity of the Murray 2 Power Station for summer 2020–21 and 2021–22, and a 170 MW decrease in the capacity of the Laverton North Power Station for winter 2016 only, based on advice from Snowy Hydro.

Table 3-8 — Summer generation capacity forecast – Victoria (MW)

	2012–13	2013–14	2014–15	2015–16	2016–17	2017–18	2018–19	2019–20	2020–21	2021–22
Sum of summer generation capacities	11,311	11,344	11,267	11,272	11,367	11,367	11,367	11,367	11,229	11,229
Assumed generation capacity available for the maximum demand	10,859	10,892	10,815	10,820	10,915	10,915	10,915	10,915	10,777	10,777

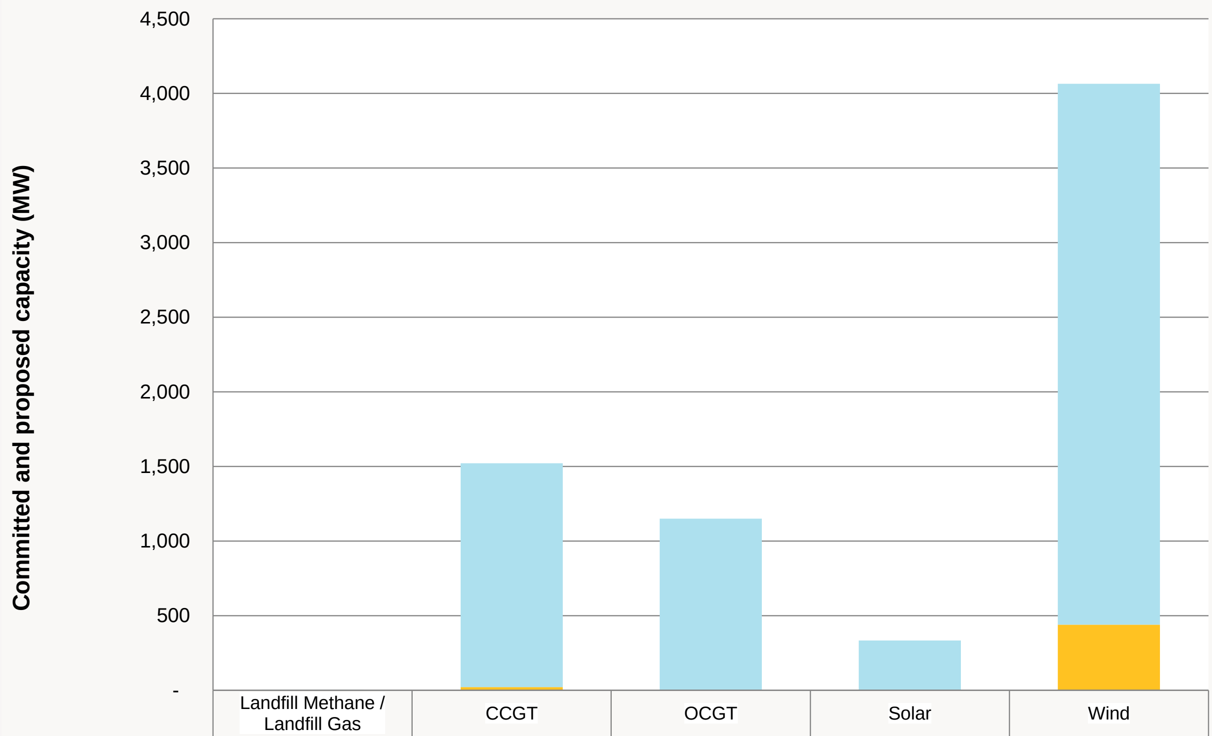
[14] See note 6.
[15] Capacity for Anglesea Power Station (registered as non-scheduled) is also included as generation rather than as a demand offset in the supply-demand outlook, because of its impact on network limitations.
[16] See note 10.

Table 3-9 — Winter generation capacity forecast – Victoria (MW)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Sum of winter generation capacities	11,738	11,770	11,789	11,624	11,699	11,699	11,699	11,699	11,699	11,699
Assumed generation capacity available for the maximum demand	11,289	11,322	11,340	11,175	11,250	11,250	11,250	11,250	11,250	11,250

Figure 3-13 shows the generation investment interest in Victoria in March 2012. The figure shows significant investment interest in wind generation and GPG, 461 MW of which involves committed projects.

Figure 3-13 — Current commitment status of public generation developments in Victoria



	Landfill Methane / Landfill Gas	CCGT	OCGT	Solar	Wind
Publicly announced	2	1,500	1,150	334	3,624
Committed		21			440

Two committed projects involving non-scheduled generating systems are expected to be commissioned in 2012–13:

- The Morton's Lane Wind Farm is a non-scheduled 20 MW development by Morton's Lane Wind Farm Pty. Ltd. (Goldwind and NewEn). This project has commenced construction.
- The Qenos Cogeneration Facility is a 21 MW gas-fuelled generating system that will provide heat and power to the Qenos plastics facility in Altona. The plant will be grid-connected to export excess power.

There have been significant changes to publicly announced proposals in Victoria since the 2011 ESOO, reflecting the projects' early stages of development, and the rapidly changing investment environment.

The Mildura Power Station, a 154 MW large-scale solar PV power plant proposed by Solar Systems (as opposed to the publicly announced Mildura Power Station proposal by Infigen Energy in New South Wales), was publicly announced in 2011 as part of the Australian Government's Solar Flagships Program, and is the only significant new generation proposal to be publicly announced since the 2011 ESOO. The other publicly announced proposal involving large-scale solar PV in Victoria is TRUenergy's 180 MW Mallee Solar Park, which was also shortlisted under the Solar Flagships Program.

There has been a net reduction of 1,171 MW in the total capacity of publicly announced wind farm proposals in Victoria since the 2011 ESOO.[17] Fourteen of the proposals included in the 2011 ESOO (totalling approximately 700 MW) have now been classified as inactive. These include the Baynton Wind Farm (240 MW), Sidonia Hills Wind Farm (80 MW), and Mortlake East Wind Farm (75 MW).

Several publicly announced proposals involving wind farms have reduced their planned capacity since last year's survey, including Darlington Wind Farm (a 249 MW reduction), Cherry Tree Wind Farm (a 50 MW reduction), and Ryan's Corner Wind Farm (a 36 MW reduction).

Interest in new GPG capacity in Victoria remains unchanged since the 2011 ESOO. There are four major publicly announced proposals, including TRUenergy's Yallourn Power Station (1,000 MW CCGT), Origin Energy's Shaw River Power Station (500 MW CCGT) and Mortlake Stage 2 Power Station (550 MW OCGT), and AGL Energy's Tarrone Power Station (600 MW OCGT).

The HRL Developments Dual Gas Demonstration Project involving a 550 MW integrated drying and gasification combined cycle (IDGCC) technology, brown coal-fuelled plant, is no longer included as a publicly announced proposal.

[17] This total does not include Morton's Lane Wind Farm, which changed from a publicly announced proposal in 2011 to a committed project in 2012.

3.5 Investment outlook in South Australia

3.5.1 Supply-demand outlook

Figure 3-14 shows the projected South Australian summer supply-demand outlook for 2012–13 to 2021–22.

The figure indicates that under the medium scenario, South Australia reaches its LRC point in 2019–20, requiring at least 24 MW of new generation or demand-side investment to delay this shortfall until the following year, compared to the 2011 ESOO's projected LRC point in 2014–15. This change in timing is mainly due to the reduced maximum demand projections since 2011.

Figure 3-14 — South Australian summer supply-demand outlook

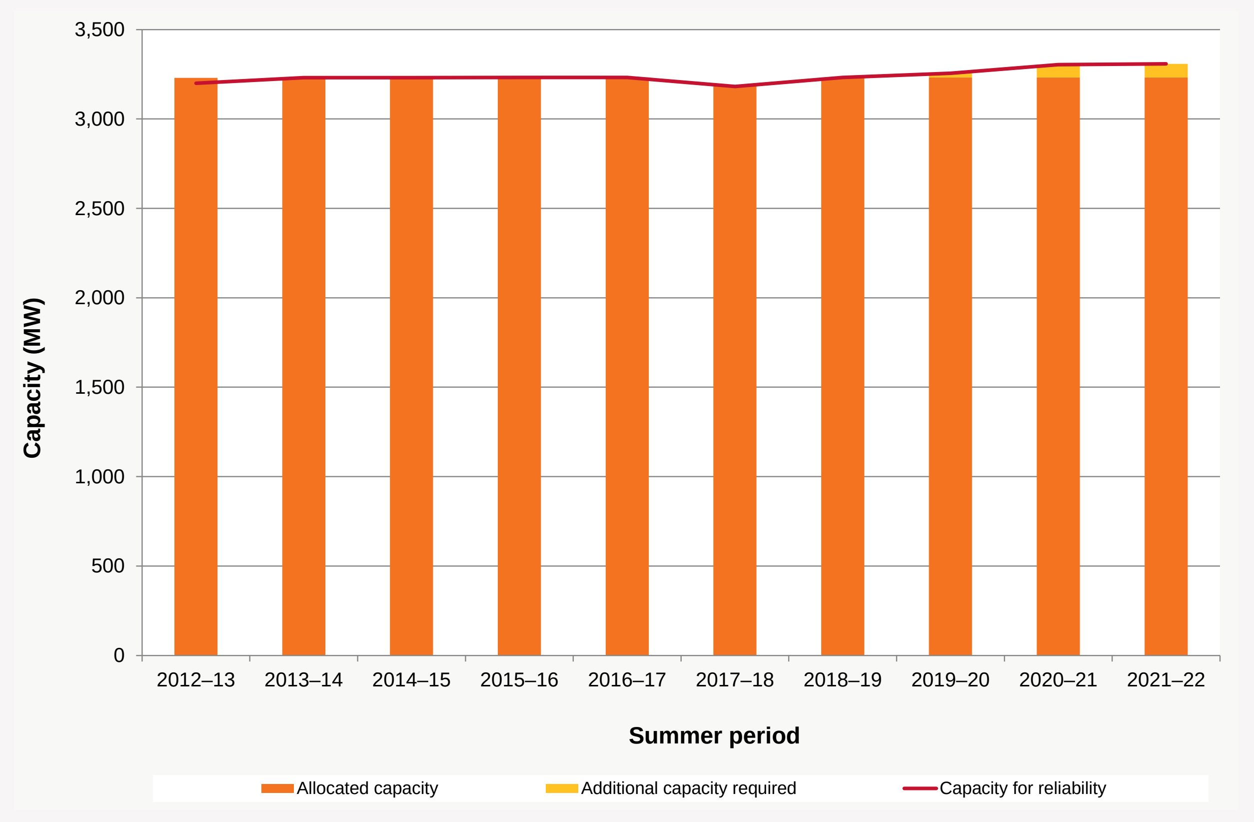


Table 3-10 shows the LRC point and reserve deficit projections for the low, medium and high scenario.

The LRC point is projected to occur under the medium scenario in 2019–20, and the high scenario in 2015–16. No LRC point occurs under the low scenario prior to 2021–22.

Table 3-10 — South Australian supply-demand outlook summary

Region	Low scenario		Medium scenario		High scenario	
	LRC point	Reserve deficit (MW)	LRC point	Reserve deficit (MW)	LRC point	Reserve deficit (MW)
South Australia (summer)	>2021–22	-	2019–20	24	2015–16	3
South Australia (winter)	>2022	-	>2022	-	>2022	-

3.5.2 Annual energy and maximum demand

Figure 3-15 shows the annual energy projection for South Australia under the low, medium and high scenario. Under the medium scenario, the average annual growth in energy over the outlook period is 0.9%.

Figure 3-15 — South Australian annual energy projections

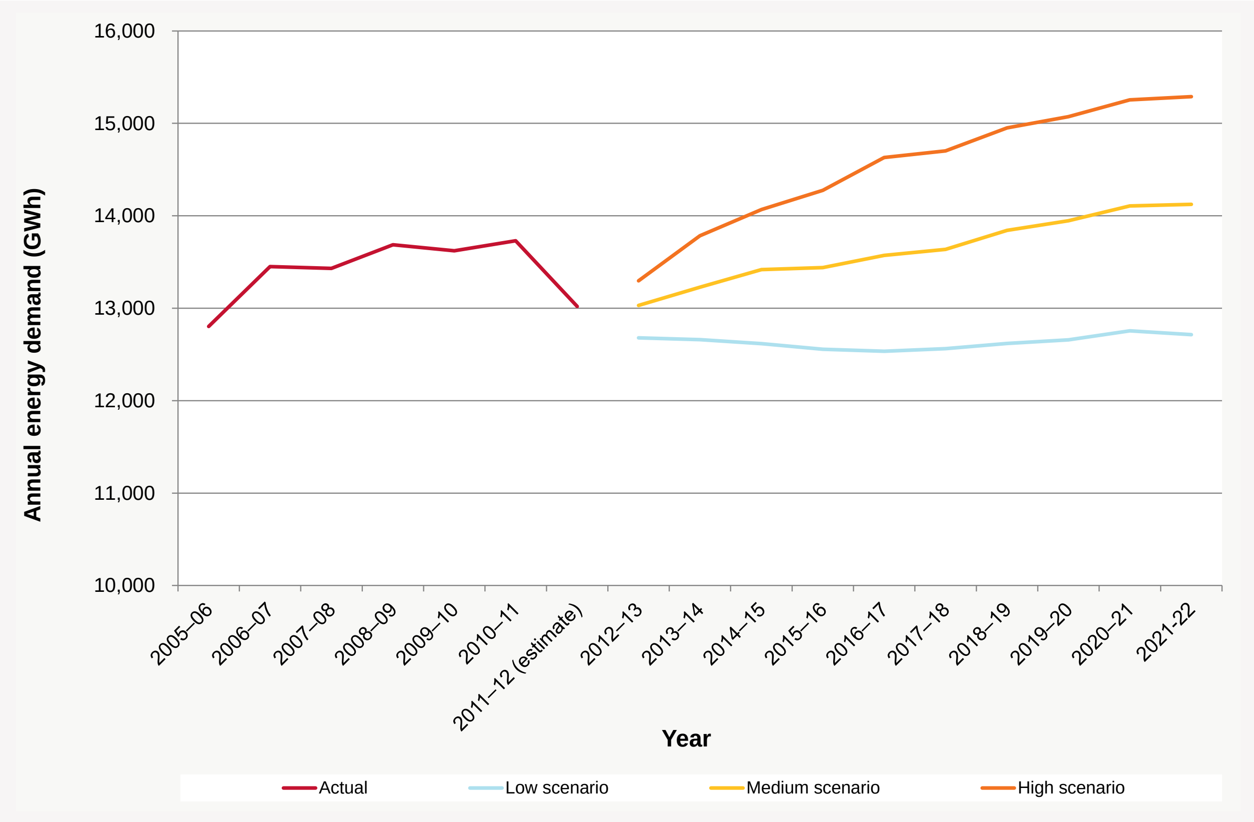
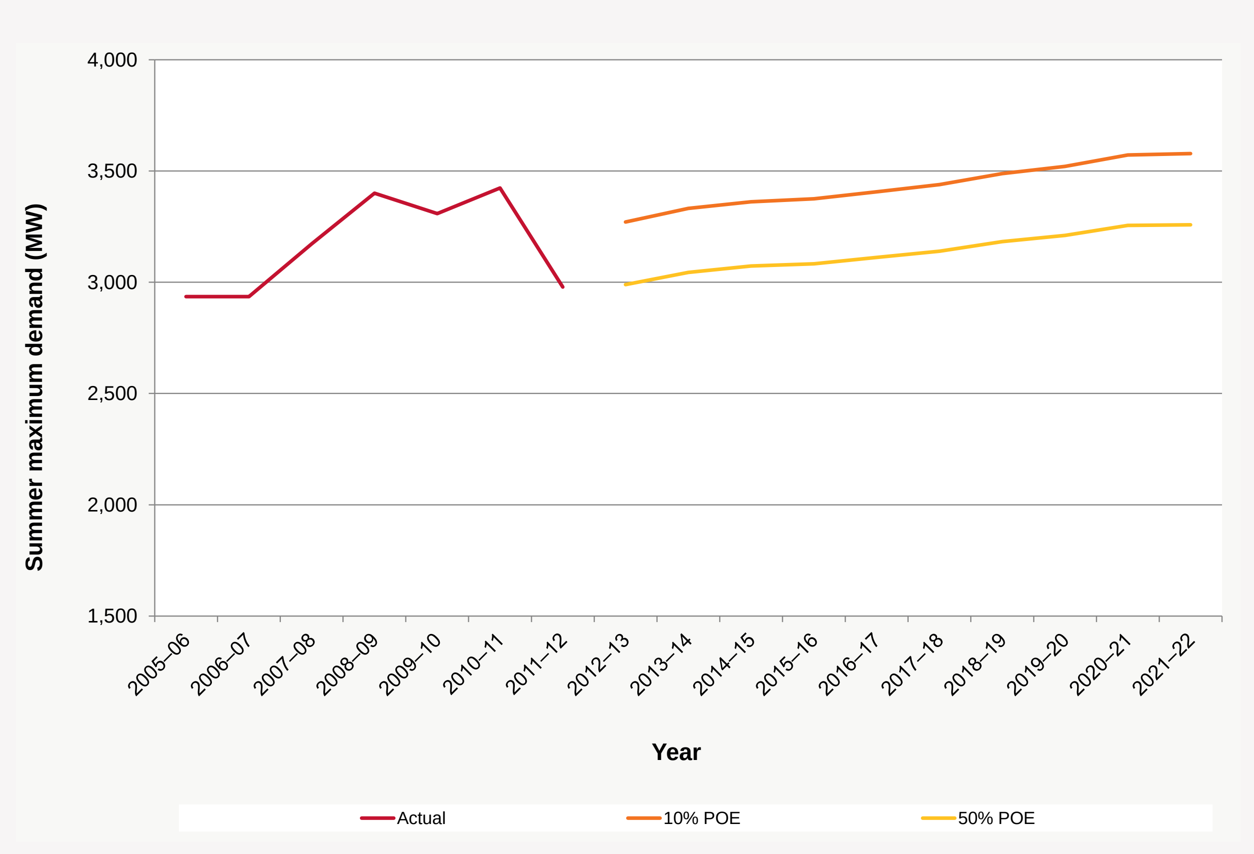


Figure 3-16 shows the medium scenario's summer 10% and 50% POE maximum demand projection for South Australia. The projected summer 10% POE maximum demand for 2012–13 is 3,271 MW, a reduction of 359 MW (10%) from 2011, and is projected to grow at an average annual rate of 1.0%, or approximately 34 MW.

Figure 3-16 — South Australian summer maximum demand projections (medium scenario)



3.5.3 Generation

This section summarises existing and committed generation capacities, and proposed generation projects in South Australia. For more detailed information about existing generation and proposed projects, see the AEMO website's Generation Information section.[18]

Table 3-11 and Table 3-12 list forecasts of summer and winter generation capacity in South Australia for the outlook period:

- The first row lists the sum of scheduled and semi-scheduled generation capacity information provided by generators in 2012.
- The second row lists assumed generation capacities available to meet the maximum demand, and used in the supply-demand outlook. A contribution factor of 8.3% for summer and 7.5% for winter is applied to the capacity of semi-scheduled wind farms.[19]

[18] See note 6.
[19] See note 10.

The capacities shown account for the following:

- Northern Power Station, a 530 MW brown coal power station, is not included in the assumed generation capacity for supplying winter maximum demand in 2013 or 2014. This is based on advice from Alinta Energy that this power station will only be available if recalled (with a recall time of up to three weeks) from 1 April 2013 to 30 September 2013 and from 1 April 2014 to 30 September 2014. After 1 October 2014, the power station will return to normal service. Alinta Energy also advises that summer operation will continue as normal.
- Playford B Power Station, a 240 MW brown coal power station also owned by Alinta Energy, is not included in the assumed generation capacity for supplying summer or winter maximum demand during the outlook period. This is based on advice from Alinta Energy that this power station will only be available if recalled, with a recall time of around 70 days for both summer and winter.
- The sum of scheduled and semi-scheduled generation capacity includes the 50 MW Angaston Power Station, which changed classification from scheduled to non-scheduled in 2011. This power station is not included in the assumed generation capacity for supplying maximum demand because it was treated as a demand offset rather than as generation in the 2012 supply-demand outlook.

Table 3-11 — Summer generation capacity forecast – South Australia (MW)

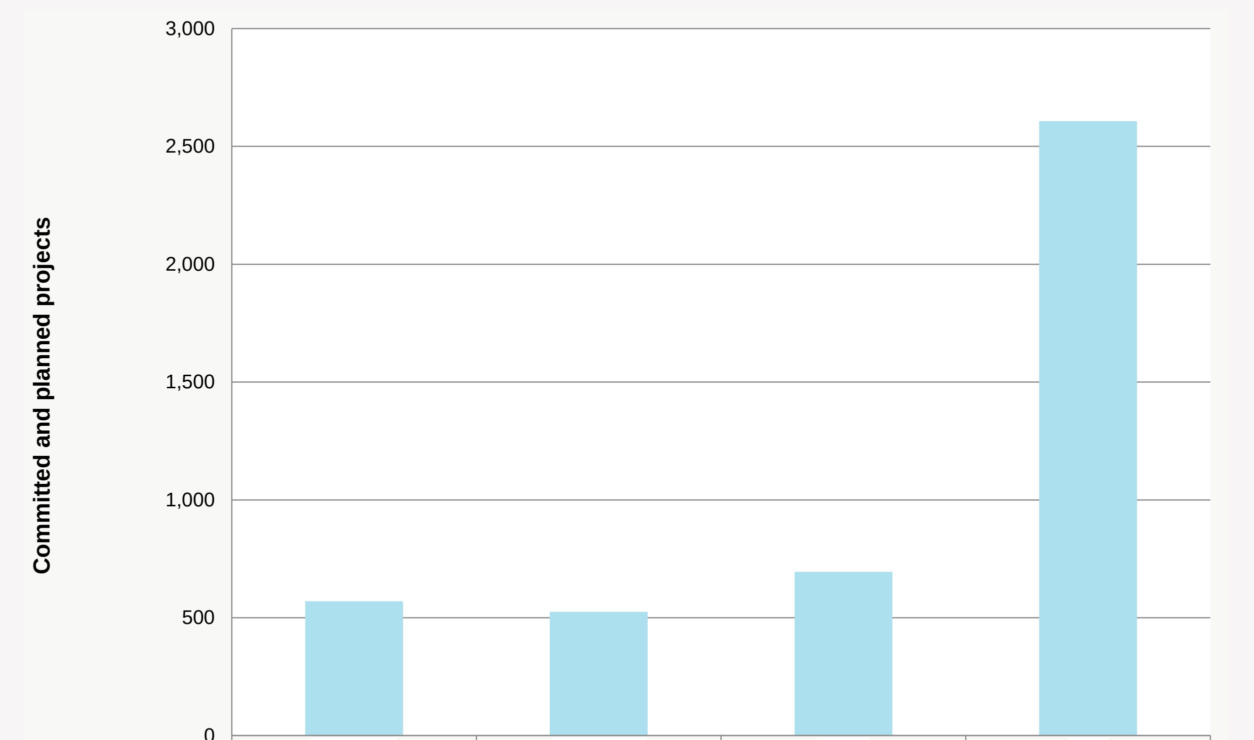
	2012–13	2013–14	2014–15	2015–16	2016–17	2017–18	2018–19	2019–20	2020–21	2021–22
Sum of summer generation capacities	4,091	4,092	4,092	4,093	4,093	4,093	4,093	4,093	4,093	4,093
Assumed generation capacity available for the maximum demand	3,230	3,231	3,231	3,232	3,232	3,232	3,232	3,232	3,232	3,232

Table 3-12 — Winter generation capacity forecast – South Australia (MW)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Sum of winter generation capacities	4,433	4,434	4,434	4,434	4,434	4,434	4,434	4,434	4,434	4,434
Assumed generation capacity available for the maximum demand	2,883	2,884	3,430	3,430	3,430	3,430	3,430	3,430	3,430	3,430

Figure 3-17 shows the generation investment interest in South Australia in March 2012. There are no committed projects or advanced proposals, and most of the publicly announced proposals involve wind farms.

Figure 3-17 — Current commitment status of public generation developments in South Australia



	Black Coal	Geothermal	OCGT	Wind
Publicly announced	570	525	695	2,607

The total capacity of publicly announced proposals involving wind farms in South Australia has not changed significantly since the 2011 ESOO. There are three new proposals, the largest of which is REpower Australia's Ceres Project, a 600 MW wind farm on the Yorke Peninsula.

There has been a 900 MW reduction in the capacity of publicly announced proposals involving GPG. AEMO has been advised that AGL Energy's 750 MW OCGT Torrens Island C proposal, publicly announced in 2011, is now inactive or unlikely to proceed.

Two major proposed projects involving geothermal generation include developments by Geodynamics at Innaminicka, and by Petratherm at Paralana. The Innaminicka project is currently focussed on demonstration plants to prove the feasibility of extracting heat for power from high-temperature granite. The Paralana plant is still investigating the geothermal resource at the project site.

3.6 Investment outlook in Tasmania

3.6.1 Supply-demand outlook

Figure 3-18 shows the projected Tasmanian summer supply-demand outlook for 2012–13 to 2021–22. Figure 3-19 also shows the projected supply-demand outlook for winter, because this is when the Tasmanian maximum demand occurs.

The figures indicate that under the medium scenario, Tasmania does not reach an LRC point during the outlook period, which is consistent with the 2011 ESOO projection.

The decline in the summer supply-demand outlook's allocated capacity is due to reserve sharing, as Tasmania provides increasing support to Victoria. This is because adjacent regions often reach maximum demand at different times, allowing the same capacity to contribute to reliability in more than one region via reserve sharing (the extent of which is captured by each region's allocated capacity).

In the winter supply-demand outlook, there is a 440 MW increase in the allocated capacity in 2015, which is due to an increase in the available supply from Basslink for that year.

Figure 3-18 — Tasmanian summer supply-demand outlook

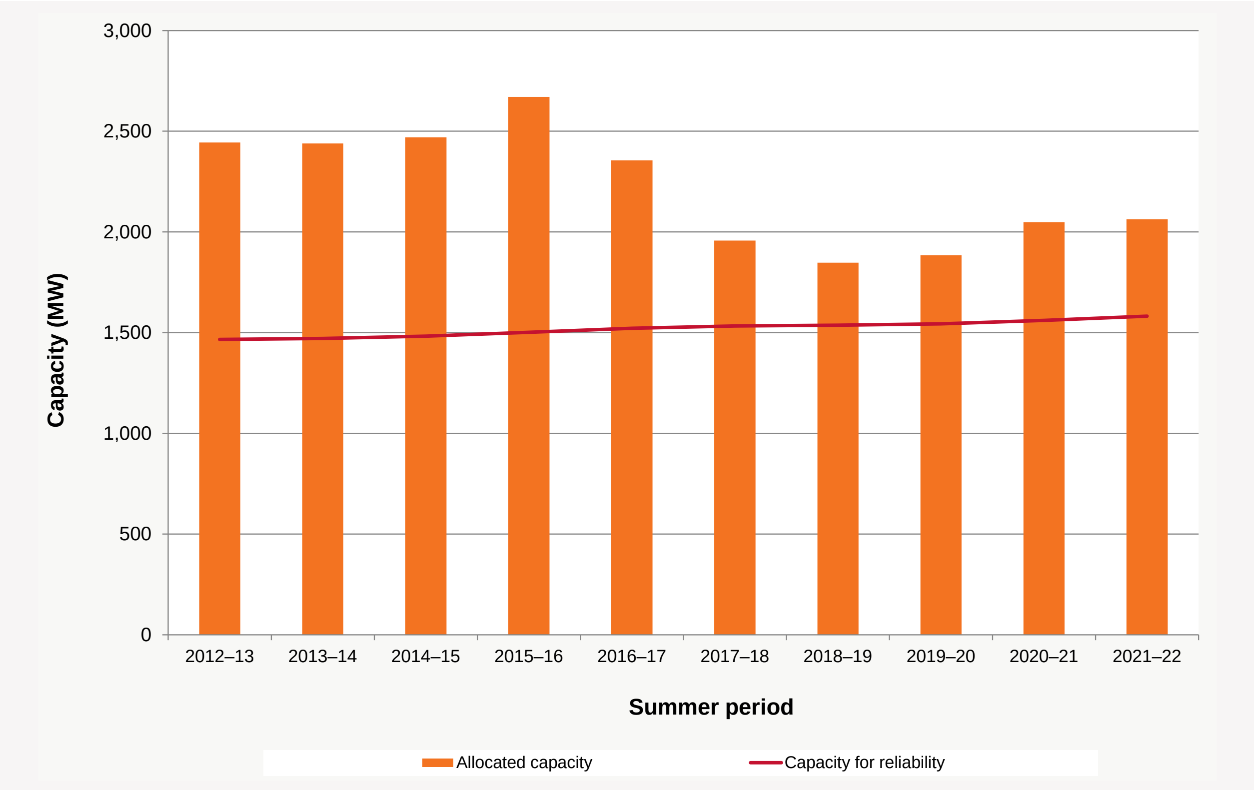


Figure 3-19 — Tasmanian winter supply-demand outlook

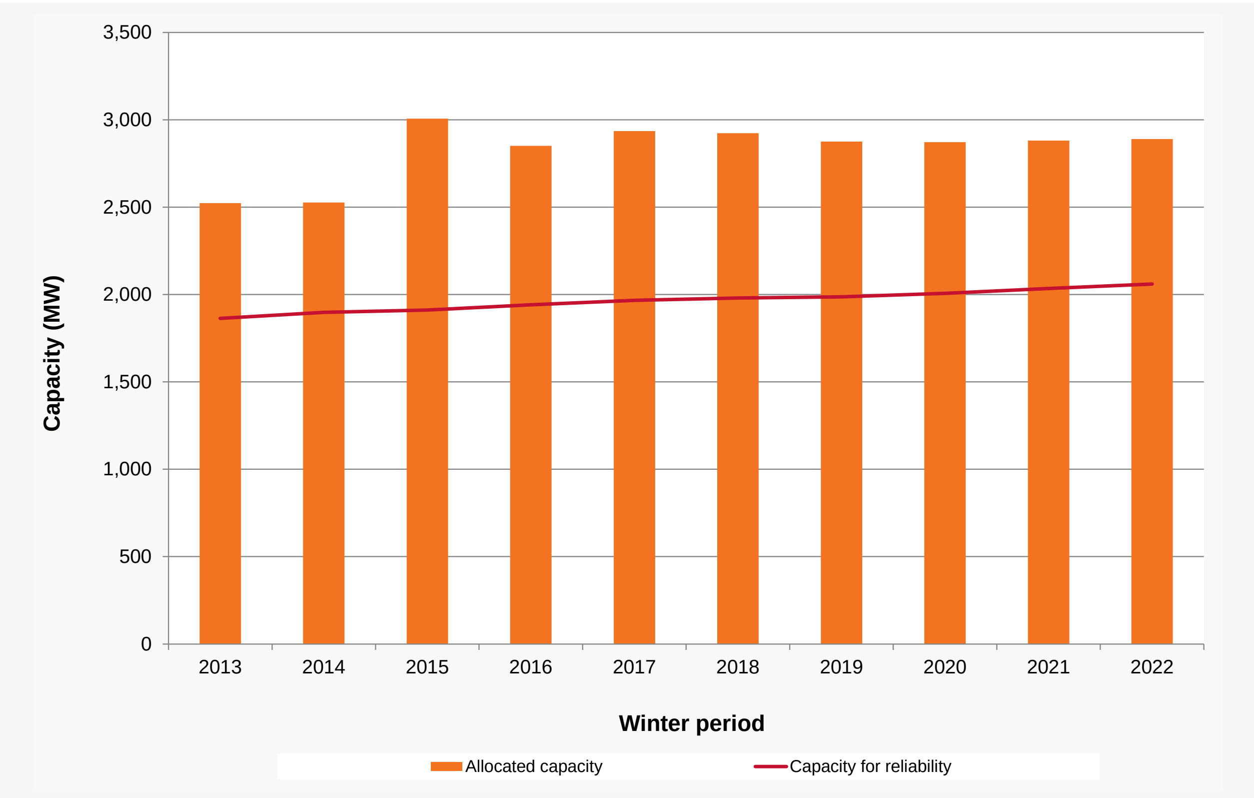


Table 3-13 shows the LRC point and reserve deficit projections for the low, medium and high scenario. Tasmania does not experience an LRC point prior to summer 2021–22 and winter 2022 under any of the scenarios.

The supply-demand outlook, however, only considers capacity adequacy and cannot indicate a reserve shortfall due to energy limitations. This is significant because Tasmania principally depends on hydroelectric generation and tends to be energy limited rather than capacity limited. For information about the Tasmanian energy adequacy assessment, see Chapter 2, Section 2.1.2.

Table 3-13 — Tasmanian supply-demand outlook summary

Region	Low scenario		Medium scenario		High scenario	
	LRC point	Reserve deficit (MW)	LRC point	Reserve deficit (MW)	LRC point	Reserve deficit (MW)
Tasmania (summer)	>2021–22	-	>2021–22	-	>2021–22	-
Tasmania (winter)	>2022	-	>2022	-	>2022	-

3.6.2 Annual energy and maximum demand

Figure 3-20 shows the annual energy projection for Tasmania under the low, medium and high scenario. Under the medium scenario, the average annual growth in energy over the outlook period is 0.9%.

Figure 3-20 — Tasmanian annual energy projections

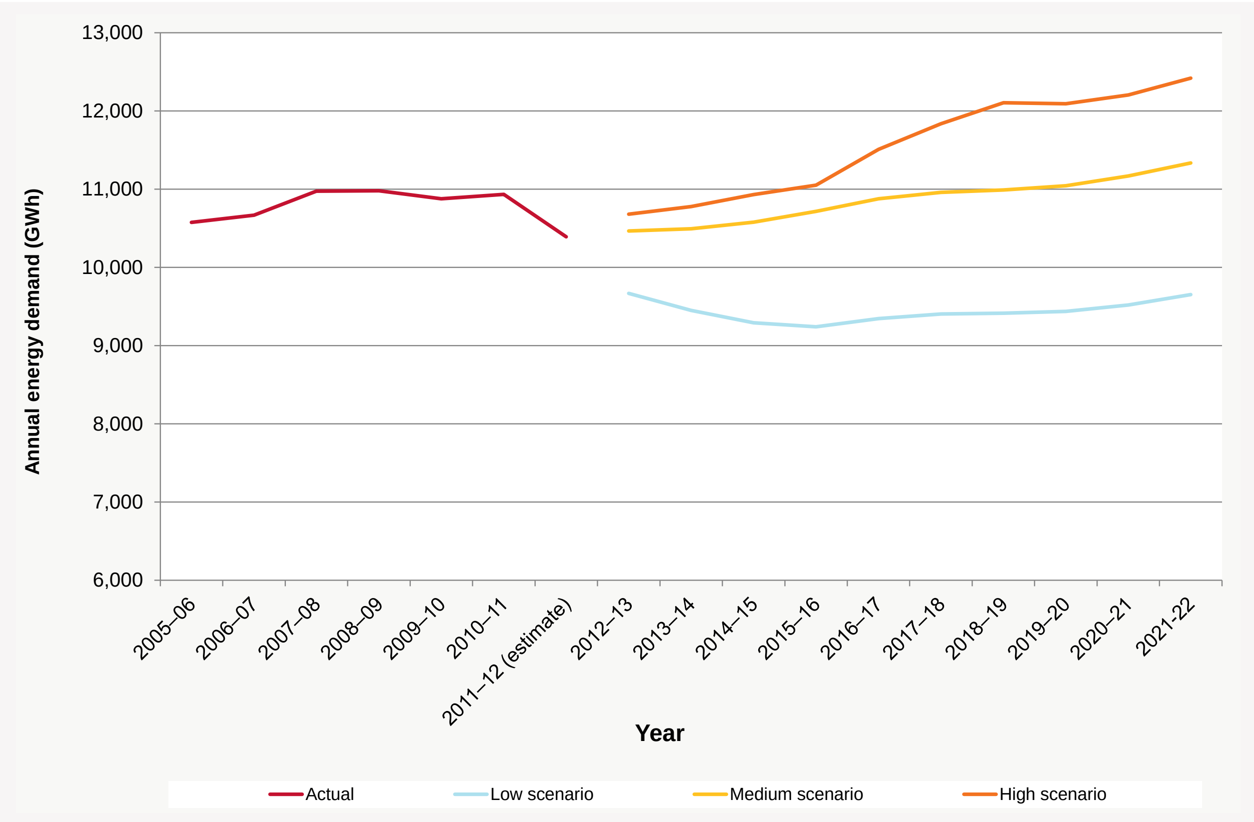
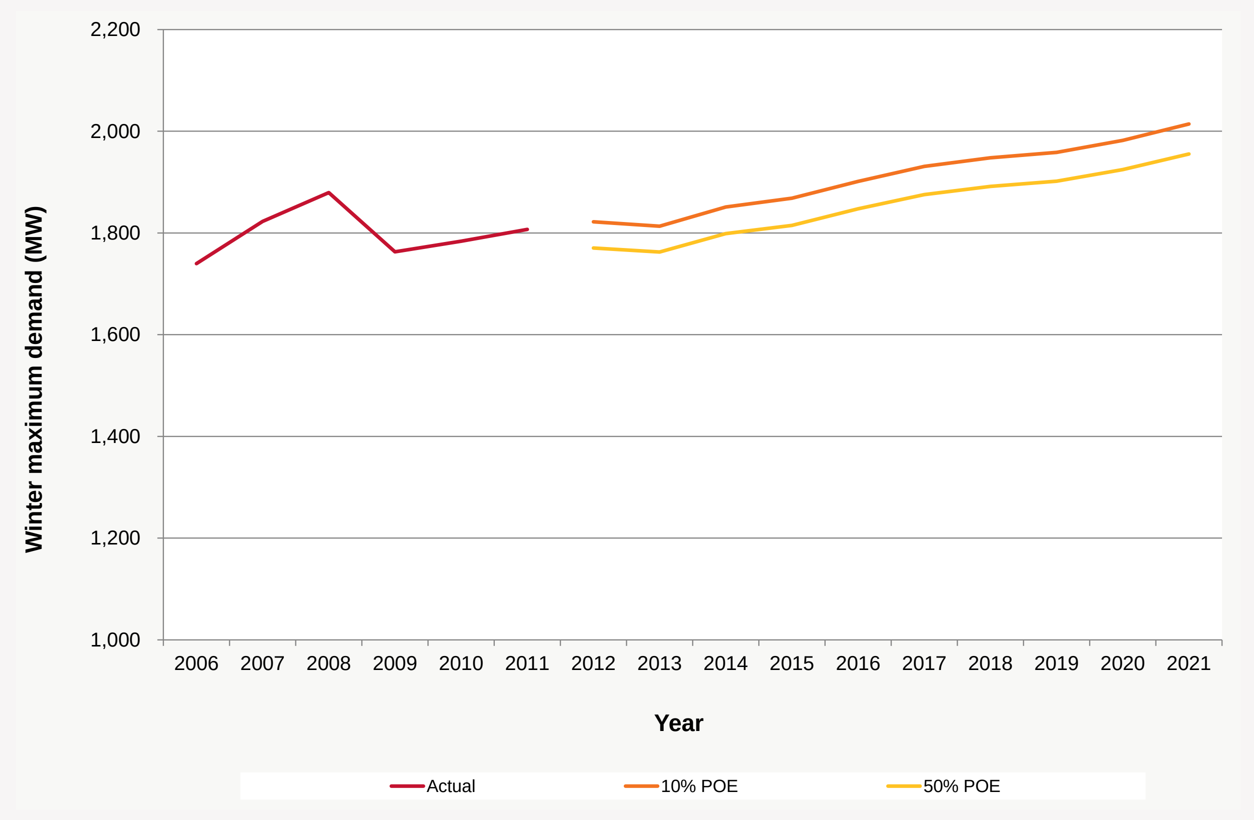


Figure 3-21 shows the medium scenario's winter 10% and 50% POE maximum demand projection for Tasmania. The projected winter 10% POE maximum demand for 2013 is 1,813 MW, a reduction of 149 MW (8%) from 2011, and is projected to grow at an average annual rate of 1.1%, or approximately 21 MW.

Figure 3-21 — Tasmanian winter maximum demand projections (medium scenario)



3.6.3 Generation

This section summarises existing and committed generation capacities, and proposed generation projects in Tasmania. For more detailed information about existing generation and proposed projects, see the AEMO website's Generation Information section.[20]

Table 3-14 and Table 3-15 list forecasts of summer and winter generation capacity in Tasmania for the outlook period:

- The first row lists the sum of scheduled and semi-scheduled generation capacity information provided by generators in 2012.
- The second row lists assumed generation capacities available to meet the maximum demand, and used in the supply-demand outlook.

  A contribution factor of 3.5% for summer and 2.9% for winter is applied to the capacity of semi-scheduled wind farms.[21]

The capacities shown account for the following:

- The 168 MW Musselroe Wind Farm by Hydro Tasmania. Musselroe is located in the north east of Tasmania, construction has commenced, and completion is expected in June 2013. There are no other committed generation projects in Tasmania.
- Variations from year-to-year are due to changes in the available capacity from various hydroelectric generators, based on advice from the Hydro Tasmania.

[20] See note 6.
[21] See note 10.

Table 3-14 — Summer generation capacity forecast – Tasmania (MW)

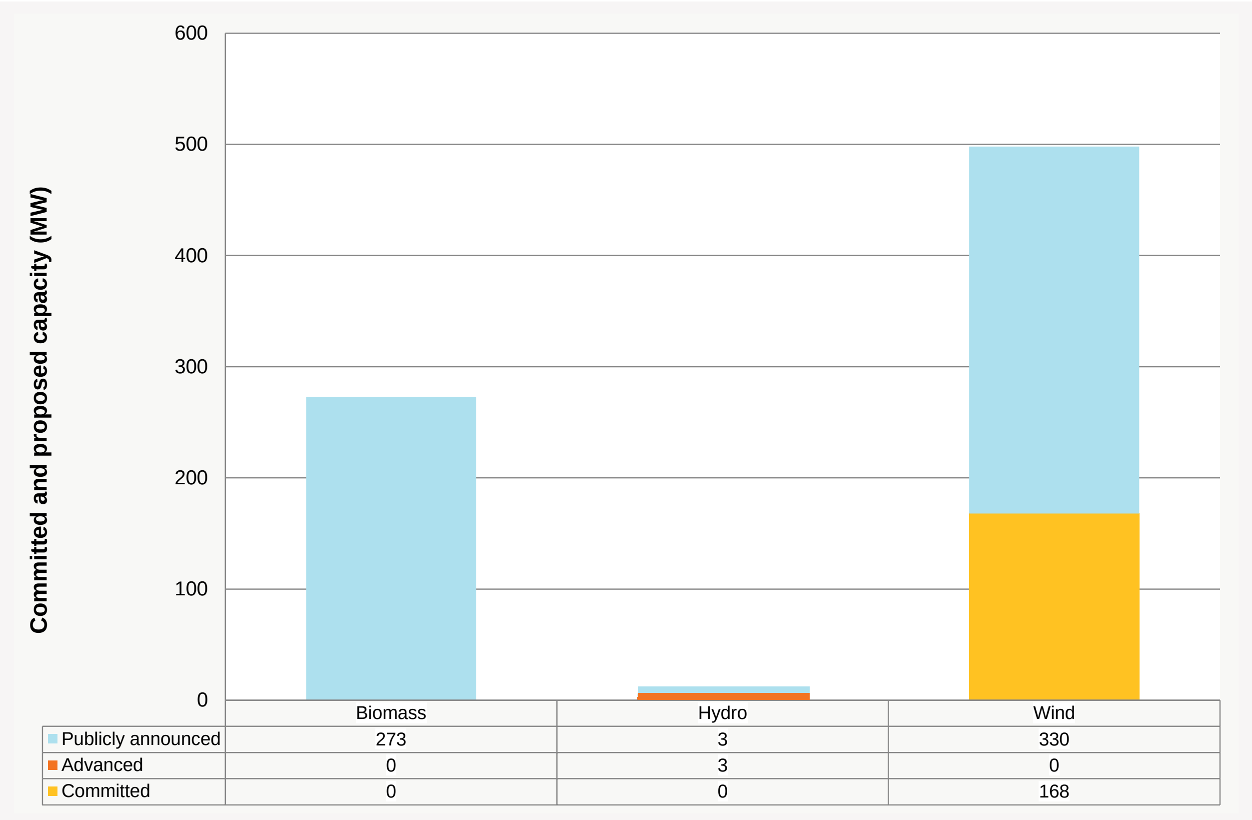
	2012–13	2013–14	2014–15	2015–16	2016–17	2017–18	2018–19	2019–20	2020–21	2021–22
Sum of summer generation capacities	2,601	2,597	2,627	2,687	2,513	2,540	2,557	2,595	2,645	2,725
Assumed generation capacity available for the maximum demand	2,444	2,439	2,470	2,530	2,356	2,383	2,400	2,437	2,488	2,568

Table 3-15 — Winter generation capacity forecast – Tasmania (MW)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Sum of winter generation capacities	2,682	2,685	2,725	2,725	2,700	2,725	2,725	2,725	2,725	2,725
Assumed generation capacity available for the maximum demand	2,524	2,527	2,567	2,567	2,542	2,567	2,567	2,567	2,567	2,567

Figure 3-22 shows the generation investment interest in Tasmania in March 2012. Investment interest is mainly split between biomass and wind generation.

Figure 3-22 — Current commitment status of public generation developments in Tasmania



The publicly announced proposals comprise the Cattle Hill and Granville Harbour Wind Farms, with capacities of 240 MW and 90 MW, respectively, and the 273 MW Bell Bay Pulp Mill cogeneration plant, which will be fuelled by wood-waste biomass.

3.7 Links to supporting information

This section provides links to other information about ESOO planning. Some of this information appeared in previous ESOOs.

Information source	Website address
AEMO Generation Information webpage	http://www.aemo.com.au/en/Electricity/Planning/Related-Information/Generation-Information
National Energy Forecasting Report	http://www.aemo.com.au/en/Electricity/Forecasting/2012-National-Electricity-Forecasting-Report
Supply-Demand Calculator and Tutorials	http://www.aemo.com.au/Electricity/Planning/Electricity-Statement-of-Opportunities/Supply-Demand-Calculator-and-Tutorials
Wind Contribution to Peak Demand	http://www.aemo.com.au/en/Electricity/Planning/Related-Information/Wind-Contribution-to-Peak-Demand

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Acknowledgement

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LIST OF MEASURES AND ABBREVIATIONS

Units of measure

The following sections list the units of measure and abbreviations used throughout the ESOO

Abbreviation	Unit of measure
GWh	Gigawatt hours
MW	Megawatts
MWh	Megawatt hours
TWh	Terawatt hours
$	Australian dollars
$/MWh	Australian dollars per megawatt hour

Abbreviations

Abbreviation	Expanded name
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
APR	Annual planning report
CCGT	Combined-cycle gas turbine
CFC	Contracts for Closure
DRET	Department of Resources, Energy and Tourism
DSP	Demand-side participation
EAAP	Energy Adequacy Assessment Projection
ESOO	Electricity Statement of Opportunities
GDP	Gross domestic product
GPG	Gas powered generation
GSOO	Gas Statement of Opportunities
IDGCC	Integrated drying and gasification combined cycle
JPB	Jurisdictional planning body
LGC	Large-scale Generation Certificate
LRC	Low reserve condition
LRET	Large-scale Renewable Energy Target
MD	Maximum demand
MMS	Market Management Systems

Abbreviation	Expanded name
MRET	Mandatory Renewable Energy Target
MRL	Minimum Reserve Level
MT PASA	Medium-term Projected Assessment of System Adequacy
NEL	National Electricity Law
NEM	National Electricity Market
NER	National Electricity Rules
NTNDP	National Transmission Network Development Plan
OCGT	Open-cycle gas turbine
PASA	Projected Assessment of System Adequacy
POE	Probability of exceedence
PSA	Power System Adequacy – Two Year Outlook
REC	Renewable Energy Certificate
RET	Renewable Energy Target - national Renewable Energy Target scheme
RERT	Reliability and Emergency Reserve Trader
SRES	Small-scale Renewable Energy Scheme
STC	Small-scale Technology Certificates
USE	Unserved energy
VAPR	Victorian Annual Planning Report

GLOSSARY AND LIST OF COMPANY NAMES

Glossary

Definitions

Many of the terms listed here are already defined in the National Electricity Rules (NER), version 50.[1] For ease of reference, these terms are highlighted in blue. Some terms, although defined in the NER, have been clarified, and these terms are highlighted in green.

Term	Definition
Advanced proposal	A proposed generation project that meets at least three and shows progress on two of the five criteria specified by AEMO for a committed project. See also 'proposed project' and 'publicly announced proposal'.
Allocated capacity	The generation capacity allocated to a region when assessing the reliability of supply. Allocated capacity is equal to the scheduled generation and semi-scheduled generation capacity within a region plus the allocated net import from neighbouring regions. See also 'capacity for reliability'.
Annual planning report	An annual report providing forecasts of gas or electricity (or both) supply, capacity, and demand, and other planning information.
Annual energy	The amount of electrical energy consumed in a year. See also 'electrical energy'.
Augmentation	The process of upgrading the capacity or service potential of a transmission line.
Australian Wind Energy Forecasting System (AWEFS)	A system used by AEMO to produce wind generation forecasts ranging from five minutes ahead to two years ahead.
Base load generating system	A generating system designed to run almost constantly at near maximum capacity levels, usually at lower cost than intermediate or peaking generating systems.
Capacity factor	The output of generating units or systems, averaged over time, expressed as a percentage of rated or maximum output.
Capacity for reliability	The allocated installed capacity required to meet a region's minimum reserve level (MRL). When met, sufficient supplies are available to the region to meet the Reliability Standard. Capacity for reliability = 10% probability of exceedence (POE) scheduled and semi-scheduled maximum demand + minimum reserve level – committed demand-side participation.
Capacity limited	A generating unit whose power output is limited.
Central dispatch	The process managed by AEMO for the dispatch of scheduled generating units, semi-scheduled generating units, scheduled loads, scheduled network services and market ancillary services in accordance with Rule 3.8.
Committed project	A committed project is any new generation development or non-regulated transmission development that meets all five criteria specified by the AEMO for a committed project – generation (see Chapter 2, Section 2.4.1 for more information).
Consumer	See customer.

[1] AEMC. Available http://www.aemc.gov.au/rules.php. Viewed 16 July 2012.

Term	Definition
Customer (electricity)	A person who engages in the activity of purchasing electricity supplied through a transmission or distribution system to a connection point.
Demand	See electricity demand.
Demand diversity	Referring to both intra and inter-regional demand diversity: • 'Intra-regional' recognises that the maximum demands at each connection point within a region might not occur at the same time, and the sum of the connection point maximum demands will exceed the regional maximum demand. • 'Inter-regional' recognises that the maximum demands of different regions may occur at different times, and the sum of the individual regional maximum demands will exceed the total National Electricity Market (NEM) maximum demand.
Demand-side participation (DSP)	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.
Diversity	The lack of coincidence of peak demand across several sources of demand, such as residential, industrial, and gas powered generation.
Electrical energy	Energy can be calculated as the average electrical power over a time period, multiplied by the length of the time period. Measured on a sent-out basis, it includes energy consumed by the consumer load, and distribution and transmission losses. In large electric power systems, electrical energy is measured in gigawatt hours (GWh) or 1,000 megawatt hours (MWh).
Electrical power	Electrical power is a measure of the instantaneous rate at which electrical energy is consumed, generated or transmitted. In large electric power systems it is measured in megawatts (MW) or 1,000,000 watts.
Electricity demand	The electrical power requirement met by generating units. The Electricity Statement of Opportunities (ESOO) reports demand on a generator-terminal basis, which includes the following: • The electrical power consumed by the consumer load. • Distribution and transmission losses. • Power station transformer losses and auxiliary loads. The ESOO reports demand as half-hourly averages.
Energy	See 'electrical energy'.
Energy Adequacy Assessment Projection (EAAP)	A quarterly report produced by AEMO about projected energy availability for each region over a 24-month period for three different rainfall scenarios. The EAAP reports the impact of the projected energy availabilities on regional electrical supply reliability in terms of long-term unserved energy (USE).
Energy limited	A generating unit that cannot operate at full capacity over the long term due to fuel or other energy source limitations. A typical example is a hydroelectric generating unit, the long-term output of which is limited by its water storage capacity.
Generating system	A system comprising one or more generating units that includes auxiliary or reactive plant that is located on the generator's side of the connection point.
Generating unit	The actual generator of electricity and all the related equipment essential to its functioning as a single entity.
Generation	The production of electrical power by converting another form of energy in a generating unit.

Term	Definition
Generation capacity	The amount (in megawatts (MW)) of electricity that a generating unit can produce under nominated conditions. The capacity of a generating unit may vary due to a range of factors. For example, the capacity of many thermal generating units is higher in winter than in summer.
Generation dispatch	See 'central dispatch'.
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.
Installed capacity	The generating capacity (in megawatts (MW)) of the following (for example): • A single generating unit. • A number of generating units of a particular type or in a particular area. • All of the generating units in a region.
Interconnector	A transmission line or group of transmission lines that connects the transmission networks in adjacent regions.
Interconnector flow	The quantity of electricity in MW being transmitted by an interconnector.
Interconnector power transfer capability	The power transfer capability (in megawatts (MW)) of a transmission network connecting two regions to transfer electricity between those regions.
Intermediate generating system	A generating system that adjusts its output as demand for electricity fluctuates throughout the day. These systems are typically in-between base load and peaking generation in terms of efficiency, speed of start-up and shutdown, construction cost, cost of electricity, and capacity factor.
Intermittent	A description of a generating unit whose output is not readily predictable, including, without limitation, solar generators, wave turbine generators, wind turbine generators and hydro-generators without any material storage capability.
Jurisdictional planning body (JPB)	An entity nominated by the relevant Minister of the relevant participating jurisdiction as having transmission system planning responsibility (in that participating jurisdiction). There are five jurisdictional planning bodies: • Queensland – Powerlink Queensland. • New South Wales – TransGrid. • Victoria – AEMO. • South Australia – ElectraNet. • Tasmania – Transend Networks.
Large-scale Renewable Energy Target (LRET)	See 'national Renewable Energy Target scheme'.
Load	A connection point or defined set of connection points at which electrical power is delivered to a person or to another network or the amount of electrical power delivered at a defined instant at a connection point, or aggregated over a defined set of connection points.
Load shedding	Reducing or disconnecting load from the power system.
Low reserve condition (LRC)	When AEMO considers that a region's reserve margin (calculated under 10% probability of exceedence (POE) scheduled and semi-scheduled maximum demand conditions) for the period being assessed is below the minimum reserve level (MRL).
Mandatory Renewable Energy Target (MRET)	See 'national Renewable Energy Target scheme'.
Market	Any of the markets or exchanges described in the NER, for so long as the market or exchange is conducted by AEMO.

Term	Definition
Market participant (electricity)	A person who is registered by AEMO as a market generator, market customer or market network service provider under Chapter 2 (of the NER).
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.
Medium-term Projected Assessment of System Adequacy (Medium-term PASA or MT PASA)	The Projected Assessment of System Adequacy in respect of the period from the eighth day after the current trading day to 24 months after the current trading day in accordance with clause 3.7.2 (of the NER).
Minimum reserve level (MRL)	The reserve margin (calculated under 10% probability of exceedence (POE) scheduled maximum demand conditions) required in a region to meet the Reliability Standard.
National Electricity Law	The National Electricity Law (NEL) is a schedule to the National Electricity (South Australia) Act 1996, which is applied in other participating jurisdictions by application acts. The NEL sets out some of the key high-level elements of the electricity regulatory framework, such as the functions and powers of NEM institutions, including AEMO, the AEMC, and the AER.
National Electricity Market (NEM)	The wholesale exchange of electricity operated by AEMO under the NER.
National Electricity Rules (NER)	The National Electricity Rules (NER) describes the day-to-day operations of the NEM and the framework for network regulations. See also 'National Electricity Law'.
National Renewable Energy Target scheme	The national Renewable Energy Target (RET) scheme, which commenced in January 2010, aims to meet a renewable energy target of 20% by 2020. Like its predecessor, the Mandatory Renewable Energy Target (MRET), the national RET scheme requires electricity retailers to source a proportion of their electricity from renewable sources developed after 1997. The national RET scheme is currently structured in two parts: • The Small-scale Renewable Energy Scheme (SRES) is a fixed price, unlimited-quantity scheme available only to small-scale technologies (such as solar water heating) and is being implemented via Small-scale Technology Certificates (STC). • The Large-scale Renewable Energy Target (LRET) is being implemented via Large-scale Generation Certificates (LGC), and targets 41,000 GWh of renewable energy by 2020.
National Transmission Network Development Plan (NTNDP)	An annual report to be produced by 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.
Network	The apparatus, equipment, plant and buildings used to convey, and control the conveyance of, electricity to customers (whether wholesale or retail) excluding any connection assets. In relation to a network service provider, a network owned, operated or controlled by that network service provider.
Network capability	The capability of the network or part of the network to transfer electricity from one location to another.
Network constraint equation	A constraint equation deriving from a network limit equation. Network constraint equations mathematically describe transmission network technical capabilities in a form suitable for consideration in the central dispatch process. See also 'constraint equation'.

Term	Definition
Network limitation	Describes network limits that cause frequently binding network constraint equations, and can represent major sources of network congestion. See also ‘network congestion’.
Network service	Transmission service or distribution service associated with the conveyance, and controlling the conveyance, of electricity through the network.
Non-scheduled generating unit	A generating unit that is not scheduled by AEMO as part of the central dispatch process, and which has been classified as such in accordance with Chapter 2 (of the NER).
Non-scheduled generator	A generator in respect of which any generating unit is classified as a non-scheduled generating unit in accordance with Chapter 2 (of the NER).
Operational demand	That part of the electricity demand supplied by scheduled, semi-scheduled, and significant non-scheduled generating units. There are a number of significant non-scheduled generating units included in the definition of operational demand: • Cullerin Range Wind Farm (New South Wales). • Capital Wind Farm (New South Wales). • Yambuk Wind Farm (Victoria). • Portland Wind Farm (Victoria). • Challicum Hills Wind Farm (Victoria). • Waubra Wind Farm (Victoria). • Mount Millar Wind Farm (South Australia). • Cathedral Rocks Wind Farm (South Australia). • Starfish Hill Wind Farm (South Australia). • Wattle Point Wind Farm (South Australia). • Canunda Wind Farm (South Australia). • Lake Bonney Wind Farm (South Australia). • Woolnorth Wind Farm (Tasmania).
Peaking generating system	A generating system that typically runs only when demand (and the spot market price) is high. These systems usually have lower efficiency, higher operating costs, and very fast start up and shutdown times compared with base load and intermediate systems.
Planned outage	A controlled outage of a transmission element for maintenance and/or construction purposes, or due to anticipated failure of primary or secondary equipment for which there is greater than 24 hours’ notice.
Plant capacity	The maximum power output an item of electrical equipment is able to achieve for a given period.
Power	See ‘electrical power’.
Power station	In relation to a generator, a facility in which any of that generator’s generating units are located.
Power system	The National Electricity Market’s (NEM) entire electricity infrastructure (including associated generation, transmission, and distribution networks) for the supply of electricity, operated as an integrated arrangement.
Power system reliability	The ability of the power system to supply adequate power to satisfy customer demand, allowing for credible generation and transmission network contingencies.
Probability of exceedence (POE) maximum demand	The probability, as a percentage, that a maximum demand level will be met or exceeded (for example, due to weather conditions) in a particular period of time. For example, for a 10% POE maximum demand for any given season, there is a 10% probability that the corresponding 10% POE projected maximum demand level will be met or exceeded. This means that 10% POE projected maximum demand levels for a given season are expected to be met or exceeded, on average, 1 year in 10.

Term	Definition
Proposed project	All generation project proposals that have come to the Australian Energy Market Operator's (AEMO) attention and are not committed. Proposed projects are further classified as either advanced proposals or publicly announced proposals.
Publicly announced proposal	A proposed generation project that has come to the Australian Energy Market Operator's (AEMO) attention, but cannot be classified as an advanced proposal.
Region	An area determined by the AEMC in accordance with Chapter 2A (of the NER), being an area served by a particular part of the transmission network containing one or more major load centres or generation centres or both.
Registered participant	A person who is registered by AEMO in any one or more of the categories listed in clauses 2.2 to 2.7 (of the NER) (in the case of a person who is registered by AEMO as a trader, such a person is only a registered participant for the purposes referred to in clause 2.5A (of the NER)). However, as set out in clause 8.2.1(a1) (of the NER), for the purposes of some provisions of clause 8.2 (of the NER) only, AEMO and connection applicants who are not otherwise registered participants are also deemed to be registered participants.
Reliability	The probability that plant, equipment, a system, or a device, will perform adequately for the period of time intended, under the operating conditions encountered. Also, the expression of a recognised degree of confidence in the certainty of an event or action occurring when expected.
Reliability and Emergency Reserve Trader (RERT)	The actions taken by AEMO in accordance with clause 3.20 (of the NER) to ensure reliability of supply by negotiating and entering into contracts to secure the availability of reserves under reserve contracts. These actions may be taken when reserve margins are forecast to fall below minimum reserve levels (MRLs), and a market response appears unlikely.
Reliability Panel	The panel established by the AEMC under section 38 of the National Electricity Law.
Reliability of supply	The likelihood of having sufficient capacity (generation or demand-side participation (DSP)) to meet demand. See also 'electricity demand'.
Reliability Standard	The power system reliability benchmark set by the Reliability Panel. The maximum permissible unserved energy (USE), or the maximum allowable level of electricity at risk of not being supplied to consumers, due to insufficient generation, bulk transmission or demand-side participation (DSP) capacity, is 0.002% of the annual energy consumption for the associated region, or regions, per financial year.
Renewable Energy Target (RET)	See 'national Renewable Energy Target scheme'.
Reserve	See 'reserve margin'.
Reserve deficit	The amount by which a region's reserve margin falls below its (specified) minimum reserve level (MRL).
Reserve margin	The supply available to a region in excess of the scheduled and semi-scheduled demand. The supply available to a region includes generation capacity within the region, demand-side participation (DSP), and capacity available from other regions through interconnectors. A region's reserve margin is defined as the difference between the allocated installed capacity (plus any DSP), and the region's scheduled and semi-scheduled demand.
Retailer	Those selling the bundled product of energy services to the customer.
Scenario	A consistent set of assumptions used to develop forecasts of demand, transmission, and supply.

Term	Definition
Scheduled generating unit	A generating unit with the following qualities: • Output is controlled through the central dispatch process. • Classified as a scheduled generating unit in accordance with Chapter 2 of the NER.
Scheduled generator	A generator in respect of which any generating unit is classified as a scheduled generating unit in accordance with Chapter 2 (of the NER).
Semi-scheduled generating unit	A generating unit with the following qualities: • Intermittent output. • A total capacity of 30 megawatts (MW) or greater. • May have its output limited to prevent the violation of network constraint equations.
Semi-scheduled generator	A generator in respect of which any generating unit is classified as a semi-scheduled generating unit in accordance with Chapter 2 (of the NER).
Significant non-scheduled generating unit	Refers to all of the following: • Market non-scheduled (MNS) generating units. • Non-market non-scheduled (NMNS) generating units and generating units exempted from registration (with an aggregate capacity greater than 1 MW), for which AEMO and the jurisdictional planning bodies (JPBs) have sufficient data to enable the development of energy and maximum demand projections.
Small-scale Renewable Energy Scheme (SRES)	See 'national Renewable Energy Target scheme'.
Spot market	Wholesale trading in electricity is conducted as a spot market. The spot market has the following qualities: • Enables the matching of supply and demand. • Is a set of rules and procedures to determine price and production levels. • Is managed by AEMO. See also 'spot price'.
Spot price	The price in a trading interval for one megawatt hour (MWh) of electricity at a regional reference node. Prices are calculated for each dispatch interval (five minutes) over the length of a trading interval (a 30-minute period). The six dispatch prices are averaged each half hour to determine the price for the trading interval.
Summer	Unless otherwise specified, refers to the period 1 November to 31 March (for all regions except Tasmania), and 1 December to 28 February (for Tasmania only).
Supply	The delivery of electricity.
System normal	The condition where no network elements are under maintenance or forced outage, and the network is operating in a normal configuration (according to day to day network operational practices).
Supply-demand outlook	The future state of supply's ability to meet projected demand.
Thermal generation	Generation that relies on the combustion of a fuel source. Thermal generation in the National Electricity Market (NEM) typically relies on the combustion of either coal or natural gas.
Transmission network	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, • any part of a network operating at nominal voltages between 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.

Term	Definition
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 (USE)	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. See also ‘Reliability Standard’.
Winter	Unless otherwise specified, refers to the period 1 June to 31 August (for all regions).

List of company names

Company Names

The following table lists the full name and Australian Business Number (ABN) of companies that may be referred to in this document.

Company	Full company name	ABN/ACN
AEMC	Australian Energy Market Commission	49 236 270 144
AEMO	Australian Energy Market Operator	92 072 010 327
AGL Energy	AGL Energy Limited	74 115 061 375
Alinta Energy	Alinta Energy (Australia) Pty Ltd	16 108 664 151
Delta Electricity	Delta Electricity Australia Pty Ltd	26 074 408 923
Energy Brix	Energy Brix Australia Corporation Pty Ltd	79 074 736 833
Eraring Energy	Eraring Energy	31 357 688 069
Eurus Energy	Eurus Energy Australia Pty Ltd	158 078 445
ERM Power	ERM Power Pty Limited	28 122 259 223
First Solar Australia	First Solar (Australia) Pty Ltd	141 686 946
Goldwind	Goldwind Australia Pty Ltd	140 108 390
HRL Developments	HRL Developments Pty Ltd	093 163 663
Hydro Tasmania	Hydro-Electric Corporation	48 072 377 158
Infigen Suntech Australia	Infigen Suntech Australia Pty Ltd	17 141 932 907
Infigen Energy	Infigen Energy Limited	39 105 051 616
Macarthur Wind Farm Pty Ltd	Macarthur Wind Farm Pty Ltd	19 106 134 507
Macquarie Generation	Macquarie Generation	18 402 904 344
Morton's Lane Wind Farm Pty. Ltd	Mortons Lane Windfarm Pty Ltd	37 126 367 600
Meridian Energy	Meridian Energy Ltd	151 800 396
NewEn	NewEn Australia Pty Ltd	98 103 702 405
Oaklands Hill Wind Farm Pty Ltd	Oaklands Hill Wind Farm Pty Ltd	126 595 935
Origin Energy	Origin Energy Power Limited	93 008 289 398
Qenos	Qenos Pty Ltd	62 054 196 771
Ratch Australia	Ratch Australia Developments Pty Ltd	30 128 669 232
REpower Australia	REpower Australia Pty Ltd	38 101 563 320
Snowy Hydro	Snowy Hydro Limited	17 090 574 431
Solar Systems	Solar Systems Pty Ltd	22 142 019 583
Stanwell Corporation	Stanwell Corporation Limited	37 078 848 674
TRUenergy	Truenergy Pty Ltd	99 086 014 968
Wind Farm Developments	Wind Farm Developments Pty Ltd	87 100 010 348

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