2010

Electricity Statement of Opportunities

for the National Electricity Market

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Preface

I am pleased to introduce AEMO's 2010 Electricity Statement of Opportunities (ESOO), which presents the outlook for Australia's National Electricity Market (NEM) supply capacity for years 2013-2020 and demand for years 2010-2020. The supply-demand outlook reflects the extent of growth, and opportunities for growth, in generation and demand-side investment.

This year, for the first time, AEMO has separated the 10-year supply-demand outlook into two documents. While the ESOO will cover years 3-10 and focus on investment matters, a separate document titled Power System Adequacy (PSA)–A Two Year Outlook will publish the operational issues and supply-demand outlook for summers 2010/11 and 2011/12. AEMO has released the ESOO and PSA together.

The ESOO is one of a collection of AEMO planning publications that provides comprehensive information about energy supply and investment, demand, and network planning. AEMO's other annual planning documents are the South Australian Supply and Demand Outlook, the Victorian Annual Planning Report and Update, the National Transmission Network Development Plan (NTNDP), and the Gas Statement of Opportunities.

AEMO expects that climate change policies will, over time, change the way in which Australia produces and consumes electricity. This is likely to take place through a shift from the current reliance on coal as a source of generation to less carbon-intensive fuel sources.

AEMO is also preparing for possible changes to consumption patterns resulting from technological developments, where smart grids, smart meters and electric vehicles may combine to change the demand landscape. Changes to the nature of generation supply and consumption will, in turn, impact the requirements for and utilisation of transmission and distribution networks.

AEMO's first NTNDP, to be released in December 2010, will consider the impact of climate change policies as part of its analysis of the efficient development of the national transmission network over a 20-year horizon.

While the ESOO has considered the impact of a potential Australian carbon policy on the NEM in its demand forecasts, and on investment in a new chapter (Chapter 2, Emerging Investment Trends), the impact of these policies will be understood more clearly following greater certainty about policy direction. The 2010 ESOO has not considered the potential impact on the NEM of a resource rent tax, or more generally any policy statements or positions since June 2010.

In this time of change, I am pleased that AEMO can provide valuable information to assist the energy sector with understanding its operating environment and adapting so that, together, we can continue to meet Australia's energy needs.

M. Zema

Matt Zema

Managing Director and Chief Executive Officer

Disclaimer

This publication has been prepared by the Australian Energy Market Operator Limited (AEMO) using information available at 20 May 2010, unless otherwise specified. AEMO must publish the Electricity Statement of Opportunities in order to comply with Clause 3.13.3(q) of the Rules.

The purpose of publication is to provide technical and market data and information regarding opportunities in the National Electricity Market (NEM).

Some information available after 20 May 2010 might have been included in this publication where it has been practicable to do so.

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

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Contents

Executive Summary

The 2010 Electricity Statement of Opportunities (ESOO) indicates opportunities for generation and demand-side investment in Australia's National Electricity Market (NEM). It presents a supply-demand outlook for each region based on maximum demand forecasts and generation capacities, within a broader overview of the investment environment.

The ESOO has traditionally presented a long-term supply-demand assessment over a 10-year outlook period. Due to differing market signals and data confidence within this timeframe, AEMO has decided to separate the 10-year adequacy assessment into two documents:

- The Power System Adequacy (PSA)–A Two Year Outlook focuses on supply adequacy and market intervention triggers in the first two years.
- The ESOO focuses on aspects of supply adequacy that may influence investment decisions in years three to ten.

2010 supply-demand outlook

The 2010 supply-demand outlook indicates that, with medium economic growth, Queensland is the first region expected to require new investment in 2013/14[1]. This change in the low reserve condition (LRC) point, from 2014/15 in 2009, is due to an increase in the Queensland minimum reserve level (MRL) and a decrease in forecast available capacity. In particular, capacity reduction results from the progressive retirement of Swanbank B by 2012/13.

Table 1 shows when each region is expected to require new investment or demand-side activity, assessed against medium, low, and high economic growth assumptions.

Table 1–Supply-demand outlook overview, 2012/13-2019/20

Region	Low economic growth		Medium economic growth		High economic growth	
	LRC point	Reserve deficit (MW)	LRC point	Reserve deficit (MW)	LRC point	Reserve deficit (MW)
Queensland	2015/16	184	**2013/14**	**726**	2012/13	716
New South Wales	2017/18	91	**2016/17**	**27**	2016/17	285
Victoria	2017/18	135	**2015/16[1]**	**249**	2014/15	222
South Australia	2017/18	11	**2015/16[1]**	**50**	2012/13	85
Tasmania (summer)	>2019/20	N/A	**>2019/20**	**N/A**	>2019/20	N/A
Tasmania (winter)	>2020	N/A	**>2020**	**N/A**	>2020	N/A

1. The Victorian and South Australian MRLs allow significant flexibility for reserve sharing between these regions. This results in coincident LRC points. See Chapter 7 for more information.

2010 energy and maximum demand forecasts

A key supply-demand outlook input is the energy and maximum demand forecast for each region. The forecasts for 2010 point to moderate and minor variations in average annual growth rate

[1] The outlook is developed based on the energy and maximum demand projections (Chapter 4), generation capacities (Chapter 5), minimum reserve levels (Chapter 6), and committed network projects (Appendix D).

projections in the regions since publication of the 2009 ESOO (see Figure 1). Moderate changes were observed for Queensland, South Australia, and Tasmania, while there were minor changes forecast for New South Wales and Victoria.

In Queensland, increased growth rates are largely due to a projected increase in demand in the Surat Basin area as a result of coal seam gas developments, gas compressor loads, and coal mining developments and their supporting infrastructure and services.

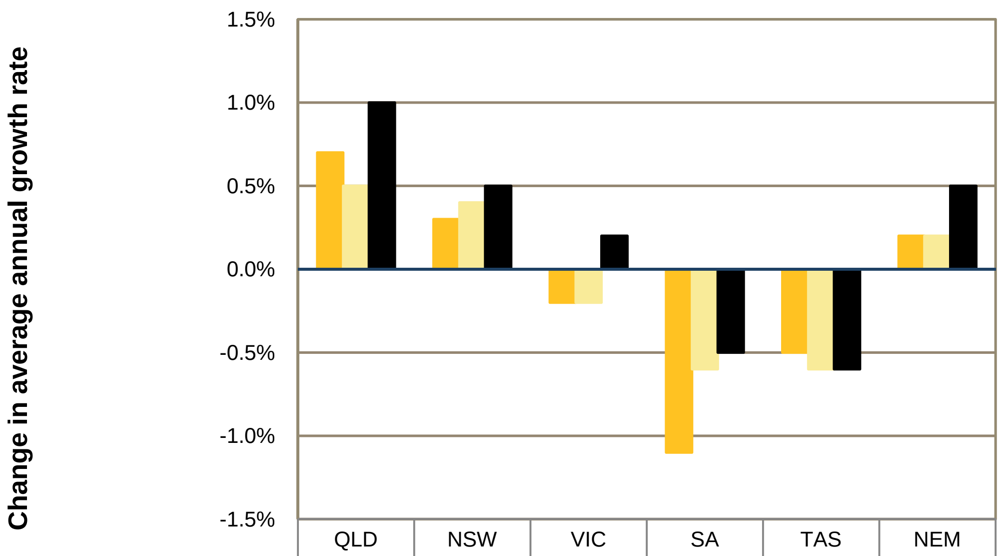
In New South Wales, the difference between the 2009 and 2010 energy projections is primarily due to a less severe economic slowdown than previously expected, but is also due to modelling assumption changes, and semi-scheduled and non-scheduled generation capacity revisions.

In Victoria, the faster recovery from the economic downturn has resulted in higher economic growth rates driving higher energy consumption. The higher outcomes in the earlier years reflect lower than previously forecast energy policy impacts on demand, and particularly policies relating to carbon emission reductions.

In South Australia, the faster economic recovery is tempered by lower population growth rates. Energy policy impacts are more pronounced in the later years (after 2013) when compared to the 2009 South Australian Annual Planning Review, resulting in significantly lower economic growth and, consequently, lower energy growth.

In Tasmania, the overall growth rate is higher than forecast by the 2009 ESOO. There is a temporary reduction in consumption in the years 2013-2015, which can be attributed to energy policy impacts on economic growth. The growth overall is due to higher growth in residential, commercial, and industrial loads, as well as considerations involving a significant new direct connect customer in 2018.

Figure 1—The change in average annual growth rates since the 2009 ESOO



	QLD	NSW	VIC	SA	TAS	NEM
Energy consumption	0.7%	0.3%	-0.2%	-1.1%	-0.5%	0.2%
Summer maximum demand	0.5%	0.4%	-0.2%	-0.6%	-0.6%	0.2%
Winter maximum demand	1.0%	0.5%	0.2%	-0.5%	-0.6%	0.5%

New minimum reserve levels

The 2010 supply-demand outlook applies new MRLs, following a recent periodic review that took account of new investments and changes to the power system. AEMO uses the MRLs to determine when a region's reserves may reach a low reserve condition (LRC) point, which is the point below which the Reliability Standard cannot be met with confidence.

The new MRLs, which were published in June 2010, have contributed to a change in LRC points in some regions.

As part of the 2010 MRL recalculation process, AEMO determined appropriate MRL values for the 2010/11 and 2011/12 financial years. For the purposes of the supply-demand outlook, the 2011/12 MRLs were adjusted to apply from 2012/13 onwards. Table 2 lists the MRLs used in the supply-demand outlook. See Chapter 6 for information about the calculation of the new MRLs.

Table 2—Minimum reserve levels, 2010/11-2012/13 (MW)

Year	Queensland	New South Wales	Victoria	South Australia	Tasmania[1]
2010/11	829	-1,548	653	-131	144
2011/12	913	-1,564	530	-268	144
2012/13 onwards[2]	913	-1,564	176	-116	144

1. The Tasmanian region is largely energy limited, rather than capacity limited. As a result, the Tasmanian MRL remains unchanged at the size of the pre-existing Tasmanian Capacity Reserve Standard. The MRL recalculation process confirmed that this value remains sufficient to meet (or exceed) the Reliability Standard
2. The 2012/13 MRL applies only in the supply-demand outlook presented in Chapter 7

The investment environment in the NEM

The results of the supply-demand outlook reflect the broader investment environment in the NEM. Chapter 2 provides an overview of the investment environment, focussing on the impact of climate change policies and emerging technologies on generation investment, the nature of demand and the impact on the transmission network. Information on generation investment is presented in Chapter 5, which provides updated information about generation capacities and proposed projects in each region.

Fuel supply

A change in the generation mix is expected, with climate change policies driving an increase in renewable and gas-fired generation. This expected increase in gas-fired generation is likely to place extra pressure on Australia's gas reserves and production facilities. The 2010 ESOO includes a new chapter on fuel supply, focusing on the level and location of coal and gas reserves in Eastern Australia.

Chapter 1 - Introduction

The Australian Energy Market Operator (AEMO) publishes the Electricity Statement of Opportunities (ESOO) each year to provide the energy industry and potential investors with information about demand forecasts, generation capacities, and supply adequacy in the National Electricity Market (NEM) for the next 10 years.

The ESOO is one of a collection of key planning publications that AEMO publishes annually. Together with the South Australian Demand and Supply Outlook, the Victorian Annual Planning Report (VAPR), the VAPR Update, the National Transmission Network Development Plan (NTNDP), and the Gas Statement of Opportunities, the ESOO aims to provide the energy market with a comprehensive body of information to guide investment decisions. Clause 13.3.3(q) of the National Electricity Rules stipulates the contents covered by the ESOO.

The two-year assessment of power system adequacy

In 2010, AEMO is dividing the publication of the 10-year supply-demand outlook between two documents, enabling readers to focus on either the immediate two-year supply-demand balance or on longer-term investment information.

The ESOO will focus on years 3-10 of the supply-demand outlook, while a second publication, the Power System Adequacy–A Two-Year Assessment (PSA), will focus on (summer) 2010/11 and 2011/12 assessed against an expected and an alternate scenario.

The PSA will also present assessments of reserve capacity, voltage control, and interconnector capability. The PSA will include an assessment of the likelihood that the Reliability and Emergency Reserve Trader process will be required.

Content and structure of the Electricity Statement of Opportunities for 2010

The NEM is facing new challenges as the energy sector seeks to adapt to public policies aimed at addressing climate change and the expected introduction of new technologies that may change the way Australians use electricity. In response to these challenges, this year the ESOO is providing additional information about some of the key issues affecting investment in the NEM.

In developing the ESOO, AEMO has also evaluated the potential impact that a carbon price (referred to in the ESOO as the ‘Australian carbon policy’) may have on generation investment and the nature of demand.

Chapter 2, Emerging Investment Trends, provides an overview of the NEM’s investment environment and focuses on the potential impact of climate change policies and emerging technologies on the nature of supply and demand, and the resulting impact on the transmission network.

Chapter 3, NEM Governance and Recent Market Development, provides an overview of the institutional structure governing the energy market. It also presents key market and policy reviews that may affect generation investment and demand-side participation in the NEM.

Chapter 4, Energy and Demand Projections, presents energy and maximum demand forecasts for the next 10 years. To account for the uncertainty surrounding the introduction of an Australian carbon policy and its impact on demand, and on the basis that the Australian Government will introduce a carbon policy of some form, AEMO has adopted a scenario-based forecast approach.

The scenarios were developed jointly with the Australian Government Department of Resources, Energy and Tourism (DRET) and a Stakeholder Reference Group.

AEMO also engaged KPMG to provide demographic, macroeconomic and sectoral forecasts consistent with these scenarios (see Attachment 1 for more information about these assumptions) to inform the development of the regional energy and maximum demand projections.

Chapter 5, Generation Capacities, presents information about generation for each region, including current capacity, planned changes to capacity, and generation for which a formal commitment or proposal to build and install has been made. In addition, Chapter 5 reports summer and winter generation capacities, as advised by plant owners. Appendix C provides further information, including the historical capacity factors for generation in each region.

Chapter 6, Reliability and Minimum Reserve Levels, presents the minimum reserve levels (MRL) for 2010 as part of a broader discussion about power system reliability.

AEMO develops the MRLs through a process of translating the Reliability Standard into a form that can be used operationally. The MRLs are also used in planning studies to assess whether the Reliability Standard, as set by the Reliability Panel, is likely to be met. The application of the MRLs, and associated minimum reserve requirements, provides market signals relating to potential generation shortfalls that may trigger AEMO intervention.

This year, AEMO engaged with industry to present and explain proposed changes to the existing MRL values previously calculated in 2006. Subsequently approved by AEMO's Board, the new MRLs have since been implemented operationally in the Medium-Term Projected Assessment of Supply Adequacy (MT PASA).

New MRLs have also been developed for both the 2010/11 and 2011/12 financial years taking account of relative demand growth between regions and committed network projects.

Chapter 7, Supply-Demand Outlook, presents the regional supply-demand balance projections, which highlight generation and demand-side investment opportunities over the next 10 years due to potential shortfalls in existing and committed supply. These projections are based on current energy and demand projections (presented in Chapter 3), known committed generation projects and capacities (presented in Chapter 4), and the revised set of MRLs (presented in Chapter 5).

Chapter 8, Fuel Supply, is a new chapter focussing on fuel supplies and information about the location, level, and usage of Australia's coal and gas resources, and liquid fuels.

Attachment 1, Economic Outlook and Government Policies, summarises the assumptions about future macroeconomic developments, government policy, consumer choice, and technological developments that informed the energy and maximum demand projections and the supply-demand outlook.

Attachment 2, Supply-Demand Outlook: Additional Information, supplements the information in Chapter 7, and provides supply-demand outlooks for a high and a low economic growth scenario, as well as a list of violating network constraint equations removed from the supply-demand outlook calculations.

The Electricity Statement of Opportunities CD and appendices

The ESOO also incorporates a CD with a number of appendices that provide more information about the energy and maximum demand projections (Appendix A), a maximum demand projection assessment (Appendix B), generation registration data and scheduled and semi-scheduled generation capacity factors for each region (Appendix C), committed network projects (Appendix D), and a map of the NEM's regional boundaries (Appendix E).

Chapter 2 - Emerging Investment Trends

2.1 Summary

This chapter provides an overview of the current investment environment in the National Electricity Market (NEM), with an emphasis on key investment trends, and focussing on the potential impact of climate change policies on generation investment, and the impact of these policies and technological developments on electricity demand.

2.2 Investment in the National Electricity Market

The NEM is experiencing a time of change, driven by climate change policies and the emergence of new technologies. By changing the economic drivers for investment in renewable and gas-fired generation, these policies are expected to shift the generation mix from a reliance on coal-fired generation towards less carbon-intensive generation sources.

Key policies driving this shift include the Australian Government's 2008 commitment to increase the amount of renewable energy through a national Renewable Energy Target (RET) scheme, combined with a reduction in greenhouse gas emissions through an Emissions Trading Scheme (ETS). These policies are designed to present a very different supply profile to the current carbon-intensive generation mix. While the Australian Government will not consider introducing an Australian carbon policy again until late 2012, the delay and associated uncertainty are expected to have significant implications for NEM investment.

A number of non-traditional technologies are also emerging as potential suppliers of electricity to the NEM, including photovoltaic (PV) and geothermal generation. Carbon capture and storage may also become viable. Together, these technologies have the potential to develop further through government funding programs that aim to improve the long-term technological development and commercialisation of low-emissions technology.

Various initiatives will also gradually change the nature of demand in the medium-long term. This is due to the potential for new technology, such as smart meters, smart grids and electric vehicles, combined with an increased focus on energy efficiency to alter consumption patterns and reduce growth rates.

2.3 Increasing generation diversity

2.3.1 Generation in the National Electricity Market

The NEM is an energy-only electricity market, with no explicit capacity-payment mechanism. The NEM's energy-only market model has attracted adequate generation investment since market-start, through its reliance on price signals in the spot and forward markets.

The NEM has a framework of market price settings. One of the key settings attracting new generation investment is the market price cap. If set correctly, the cap should provide appropriate signals for efficient investment in new generation and in the voluntary demand-reduction opportunities needed to maintain long-term supply reliability. The NEM price cap increased from $10,000/MWh to $12,500/MWh on 1 July 2010.

New investment since market-start has largely seen gas-fired and wind generation complement existing and predominantly coal-fired generation. Kogan Creek Power Station (750 MW) represents the only major greenfield investment in coal-fired generation in the last five years.

Within the energy-only market there are safety nets and a Reliability Standard that seek to deliver adequate reliability in the form of a generation margin over demand. Chapter 3 and Chapter 6 refer to the recent Reliability Panel review of the Reliability Standard and Settings.

2.3.2 Energy sector adaptation

Due to a reliance on coal-fired generation, which currently supplies approximately 82% of electricity generation in the NEM, the electricity sector contributes 35% of Australia's greenhouse gas emissions[2]. As a result, electricity will be one of the main sectors of the economy under pressure to adapt to climate change mitigation measures. In this process of adaptation, the proportion of lower CO2-emitting generation in the NEM is likely to increase relative to coal-fired generation. This shift will be mainly driven by incentives embedded in the national RET scheme and a future carbon policy.

New generator connections

New generator connections across the NEM confirm the emphasis on lower CO2-emissions technologies, partly in response to the national RET scheme. The impacts of climate change policy on the nature of generation in each region are reflected by the fuel types of generation applying for connection. In Queensland, Powerlink advises that there are connection applications for one liquid fuel plant, two combined-cycle gas turbines (CCGT), one open-cycle gas turbine (OCGT), and one gas-fired cogeneration plant[3].

In New South Wales, Transgrid advises that there are two active gas-fired generation connection enquiries in excess of 600 MW each. There are also a number of gas-fired generation proposals at the pre-commitment stage. Transgrid also received preliminary connection enquiries from six wind projects between 100 MW and 500 MW, which have since been put on hold, citing sensitivity to policy settings. There have also been preliminary connection enquiries from two solar developments, but Transgrid expects that the proposals will likely depend on the extent of Australian Government subsidies.

In Victoria, connection applications have increased from four in 2004, to twenty-five in June 2010. The fifteen currently active connection applications (at June 2010) total approximately 5,350 MW. Ten applications are for wind generation and five are for gas-fired generation. At the same time, of the active connection enquiries totalling between 4,200 MW to 4,500 MW, six are for wind, five are for gas-fired and two are for solar. There are currently no applications to connect new coal-fired generation.

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[2] The Garnaut Climate Change Review, Final Report, 2008.

[3] Powerlink, Annual Planning Report, 2010.

In South Australia, new publicly-announced generation proposals are largely wind generation projects. There are two geothermal projects, with the first providing a total of 525 MW capacity, and expected to provide local load in 2015 and to connect to the grid in 2018, and the second being a 3.75 MW pilot project. One publicly-announced integrated combined-cycle generation plant at Ackaringa will establish a conventional open cut coal mine, followed by the processing of an oil refinery petro-chemical plant[4].

In Tasmania, Transend advises that a number of proponents are investigating connecting wind farms, wave power plants, and thermal and geothermal power plants[5].

The national Renewable Energy Target scheme

The national 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, the national RET scheme requires electricity retailers to source a proportion of their electricity from renewable sources developed after 1997. The renewable energy obligation has been implemented through an obligation to acquit Renewable Energy Certificates (RECs). Eligible renewable sources create RECs in proportion to their output. These RECs can be traded, banked or sold to retailers that must surrender them in proportion to their share of the national target. In 2011, the RECs obligation will total 14,825 GWh, increasing annually until it reaches 45,000 GWh in 2020.

In February 2010, the Australian Government announced changes to the national RET scheme, separating small-scale and large-scale renewable supply. From January 2011, the scheme will exist in two parts, the Small-scale Renewable Energy Scheme (SRES) and the Large-scale Renewable Energy Target (LRET). The SRES is a fixed price, unlimited-quantity scheme available only to small-scale technologies such as solar water heating.

The LRET will retain the REC's existing floating price, fixed-quantity structure, and will be available only to large-scale power generation, such as wind, solar, biomass and geothermal energy. The LRET target will be 4,000 GWh less than the existing national RET scheme target, requiring the scheme to deliver 41,000 GWh of renewable energy by 2020.

Large-scale Renewable Energy Target impacts

In the short term, the LRET is expected to attract considerable new investment in wind generation, which is currently the most abundant, commercially-viable renewable technology. AEMO's 2009 National Transmission Statement[6] presented results from a market simulation model incorporating a fixed wind generation expansion plan designed to meet the national RET scheme target. The results indicate that new wind generation is likely to exceed 5,500 MW in new investment, predominantly in South Australia, Victoria, and New South Wales.

The potential expansion of wind generation, and the intermittent nature of its contribution, provides a potential market opportunity for peaking generation, particularly from open-cycle gas turbine technology. The intermittent nature of wind generation and its uncertain availability during times of peak demand reduces its effective contribution for planning purposes, and probabilistic approaches are used to assess its contribution.

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[4] Further information is provided in AEMO's 2010 South Australian Supply and Demand Outlook, (www.aemo.com.au).

[5] Transend, Annual Planning Report, 2010.

[6] AEMO, National Transmission Statement, 2009.

2.3.3 Technologies currently meeting national Renewable Energy Target scheme obligations

The register of RECs maintained by the Australian Government Office of the Renewable Energy Regulator (ORER) provides information about the generation technologies retailers are purchasing energy from to meet their national RET scheme obligations. ORER figures in 2009 indicate a noticeable increase in the number of RECs purchased by retailers from producers using bagasse, black liquor, landfill gas, sewage gas, and wood waste. Figure 2-1 shows the trend in this production from 2005–2009. Table 2-1 lists the technologies involved and their level of maturity.

Figure 2-1—Renewable Energy Certificates by fuel source

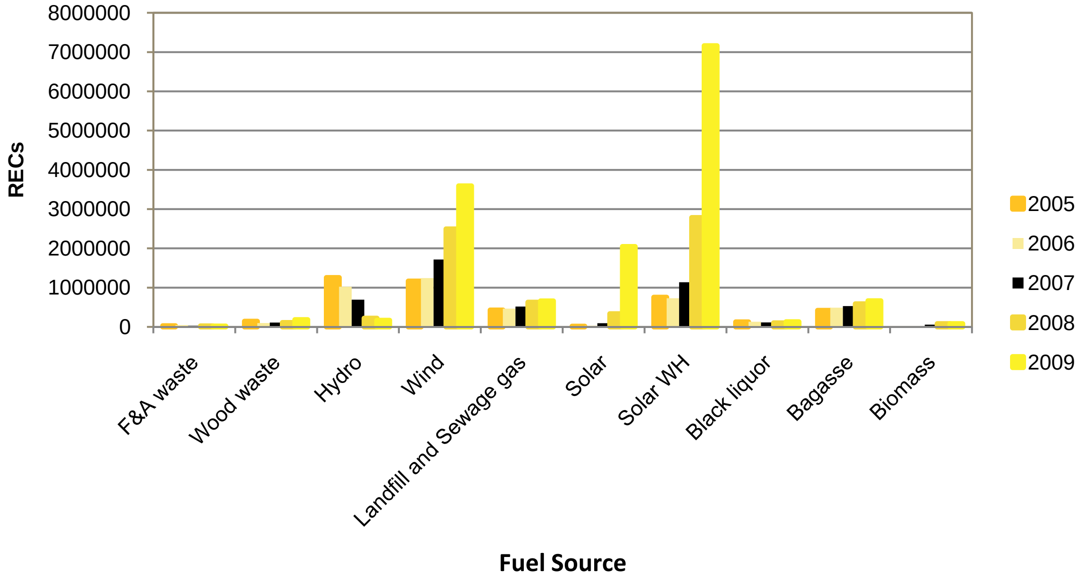

Table 2-1—Qualitative comparison of various grid-connected eligible national Renewable Energy Target scheme generation types

Technology	Potential scale	Maturity	Relative current cost
Hydro	Few remaining opportunities	Mature	Moderate
Black liquor (paper by-product)	Few remaining opportunities	Mature	Low
Bagasse (sugar cane product)	Moderate	Mature	Moderate
Wood waste	Small	Mature	Low
Landfill gas	Small	Mature	Moderate
Sewage gas	Few remaining opportunities	Mature	Low
Wind	Unlimited	Technology has substantially advanced in last 15 years but is now reaching maturity	Moderate
Solar thermal	Unlimited	Immature	High
Large-scale solar photovoltaic	Unlimited	Technology mature but mass-production processes are immature and expensive	Very high
Geothermal	Unlimited	Speculative, post-2015	Very high
Wave energy	Unlimited	Speculative, post-2020	Very high

As the lowest-cost REC generation with unlimited resources, wind generation will provide the bulk of the necessary generation for the national RET scheme target in the short-medium term, making its economics key to driving the REC price.

Emerging generation technologies, such as geothermal energy and wave power, may also impact the composition of generation in the longer term. There are currently no committed proposals for significant, grid-connected generation using these technologies.

Government support for low emissions generation development

The national RET scheme is complemented by other government initiatives aimed at promoting the development, commercialisation, and deployment of renewable energy and enabling technologies. For example, the Australian Government established a $5.1 billion Clean Energy Initiative (CEI) comprising the:

- Carbon Capture and Storage Flagships Program, which supports the construction and demonstration of large-scale, integrated carbon capture and storage projects in Australia
- Solar Flagships Program, which supports the construction and demonstration of large-scale, grid-connected solar power stations in Australia
- Australian Solar Institute (ASI), which aims to increase the cost-effectiveness of solar technologies and accelerate the capacity of solar industries in Australia
- Australian Centre for Renewable Energy (ACRE), which will invest in excess of $560 million towards the Renewable Energy Demonstration Program, Second Generation Biofuels Research and Development Program, Wind Energy Forecasting Capability Program, Advanced Electricity Storage Technologies program (aimed at supporting the development and demonstration of efficient electricity storage technologies for use with variable renewable generation sources such as wind and solar)
- Advanced Electricity Storage Technologies program, which is aimed at supporting the development and demonstration of efficient electricity storage technologies for use with variable renewable generation sources such as wind and solar, and
- Geothermal Drilling Program, which provides $50 million in total for companies seeking to develop geothermal energy.

Australian carbon policy impacts

In late 2008, the Australian Government committed to introduce an ETS. The Carbon Pollution Reduction Scheme (CPRS) Bill 2009 proposed a cap and trade mechanism to meet an upper carbon reduction limit that will increase over time.

In April 2010, the Prime Minister announced a delay in implementing the CPRS until after the current Kyoto Protocol commitment period, and only when there is greater clarity about the position of major economies on climate-change issues.

AEMO’s 2009 National Transmission Statement (NTS) delivered a broad assessment of the impact of the CPRS and different carbon price trajectories for the next 20 years using the information available at the time. The simulations examined the generation mix driven by both a Lower Carbon Price Scenario (LCPS) and a Higher Carbon Price Scenario (HCPS).

In brief, the NTS assessment predicted:

- high growth in gas-fired generation (predominantly combined-cycle), and
- a significant change in the generation portfolio over the next decade, even under the LCPS.

For example, under the LCPS the generation mix included:

- approximately 6,000 MW of new CCGT generation by the end of 2018/19, increasing to 16,300 MW by 2028/29
- wind, based on a fixed expansion, totalling nearly 6,000 MW

- approximately 1,700 MW of new OCGT generation
- less coal-fired generation due to retirements and a lack of new investment (with coal still remaining the single most dominant technology), and
- 2,500 MW of geothermal generation, but not until 2025/26.

Based on the policy setting assumed in the 2009 NTS, the modelling highlighted that the higher carbon price trajectories will increasingly affect the existing generation fleet and the associated new investment required. The 2010 NTNDP will provide further information about a larger number of scenarios, updated to reflect more recent changes to carbon policy.

Scenarios

The analysis presented in the 2010 ESOO has considered three possible scenarios to account for the uncertainty surrounding the possible introduction of a carbon price and the price itself (medium, high, low). See Section 2.5.3 for more information about the NTNDP scenarios.

2.4 The changing nature of demand

A number of factors influence levels of energy and maximum demand (MD), including economics, government policies, demographics, technological developments, weather patterns, metering technology, and transmission network tariff design.

Like the generation mix, the NEM’s demand profile is expected to change over time, driven by changing consumption patterns. Consumer behaviour is expected to change as a result of policy responses to climate change that are likely to include an increase in energy conservation, distributed generation, greater demand-side participation (DSP), and greater price discovery through smart meters and smart grids. In the longer term, greater electricity and transport sector convergence, through the increased adoption of electric vehicles, may also create different consumption patterns.

The NEM’s energy-only market arrangement tends to provide retailers with clear pricing signals for half-hourly metered medium to large customer loads at peak times and times of shortage, facilitating some level of retailer and customer response. While there are a number of examples of retailers and customers developing load-management schemes to avoid high prices, the overall penetration of these schemes is still quite small. Its potential in the future may be significantly enhanced as improved communication and other potential facilitating mechanisms, such as smart grids, become more common.

Smaller customer loads are metered in aggregate over a period of time, with demand charged on the basis of a deemed load profile. This provides smaller customers with little incentive to respond to high-price periods. Over the next decade, AEMO expects the roll out of interval metering technology, smart grids, and smart appliances to customers in this category in some regions. This has the potential to raise customer awareness about consumption decisions and, potentially, provide incentives to change both the time-of-day when consumption occurs and improve the efficiency of appliances.

2.4.1 Demand forecasting

To forecast demand, AEMO and the jurisdictional planning bodies (JPBs) consider a number of factors based on information provided by an economic consultant (see Chapter 4 for more information). These factors include national population and economic growth, the introduction of carbon pricing in 2013/14, an increase in the use of solar hot water and small-scale, roof-top photovoltaic generation, and the adoption of plug-in electric vehicles. Both population and economic growth are uncertain, as are the levels of technological adaptation. To deal with this uncertainty, AEMO takes a scenario-based approach with all its planning documents.

2.4.2 Policy influences on demand-side participation

A number of government policies aim to change demand behaviour. The Australian Government established a Task Group on Energy Efficiency to advise about the options available to improve energy efficiency by 2020.

This follows previous, similarly-targeted policy commitments, the first of which was the 2007 Council of Australian Government's (COAG) commitment to roll out smart meters to introduce time-of-day pricing and to enable users to better manage demand for peak power.

Smart meters and smart grids

The Australian Government has established the Smart Grid Smart City initiative, which is aimed at supporting the installation of Australia's first commercial-scale smart grid. The prospect of smart grids creates opportunities for consumers to change their energy consumption at short notice in response to a variety of signals that include price. This change in consumption increases the complexity of load forecasting.

The Australian Energy Market Commission (AEMC) acknowledged the potential of smart meters and smart grids to increase DSP in the energy market in Stage 2 of its review of the role of DSP in the NEM[7]. The AEMC commenced this review to identify barriers or disincentives within the National Electricity Rules (NER) inhibiting the efficient use of DSP. It concluded that, in the context of the current technology, pricing and demand conditions, the NEM framework does not impede the use of DSP.

Electric cars

The New South Wales and Victorian Governments have both established initiatives to further explore the potential of electric cars. The Victorian Government will be conducting a trial to understand the process, timelines and barriers for transitioning to electric vehicle opportunities. AEMO's long-term demand forecasts have considered the adoption of electric vehicles and their impact, particularly their potential contribution to demand and their impact on reserve levels.

2.4.3 Demand-side participation and the National Transmission Network Development Plan

In recognition that DSP may increase, the 2010 NTNDP will consider a scenario that includes high DSP (the 'fast rate of change' scenario). See Chapter 3 for more information about the Task Group on Energy Efficiency and the AEMC DSP review.

[7] AEMC. Final Report for Stage 2 of the Review of Demand Side Participation in the National Electricity Market. Available at http://www.aemc.gov.au/Market-Reviews/Open/Review-of-Demand-Side-Participation-in-the-National-Electricity-Market.html. Viewed June 2010.

2.5 Transmission network planning implications

A changing generation technology mix, and the changing distribution of generation projects geographically and in the 'merit order' of new generation, will potentially require transmission network adaptation. Where the development of new generation requires transmission network augmentation, factors relevant to the investment decision include the cost of connection (related to the proximity of the project to existing transmission infrastructure) and the extent of transmission network congestion affecting the connection point.

While not an isolated case, the transmission network in South Australia provides a cogent example. South Australia is already facing the challenge of transferring increasing amounts of wind generation in the mid-north and south east of the State. The AEMO 2009 National Transmission Statement confirmed increasing levels of congestion as a result of generation investment in South Australia. Joint investigations by AEMO and the South Australian JPB are assessing the implications for the transmission network of further renewable generation investments in South Australia. The outcomes of this joint planning study will be published in a dedicated report and will inform the 2010 NTNDP.

Efficient frameworks for network augmentation, as well as an effective congestion management system, will also become increasingly necessary to:

- ensure the management of congestion that may result from new wind generation, and
- meet reliability standards.

AEMO's Congestion Information Resource, to be released on 1 September 2010, will provide information about patterns of network congestion and projections of market outcomes in the presence of network congestion.

2.5.1 Connecting remote generation

A key challenge for the transmission network will be adapting a network that developed around coal-fired generation (frequently concentrated near coal mines) to new generation configurations, including increased renewable generation. Some excellent renewable generation resources are located remotely from transmission networks, presenting a significant challenge for existing connection frameworks that place the onus on the proponent for a connection and its costs.

In recognition of this, and following the Review of Energy Market Frameworks in Light of Climate Change Policies, the AEMC is considering whether there are advantages in arrangements to facilitate efficient transmission development in resource-rich areas where multiple projects are likely to be developed. Currently referred to as Scale-Efficient Network Extensions (SENEs), the intention is to explore efficient mechanisms for connecting multiple generating systems.

The AEMC is currently consulting on SENEs and an outcome is not expected before early 2011.

2.5.2 Transmission Frameworks Review

The AEMC has commenced the Transmission Frameworks Review to consider the efficient provision and utilisation of the transmission network. The review stems from the Review of Energy Market Frameworks in Light of Climate Change Policies, and reflects the AEMC's finding that climate change policies will fundamentally change the utilisation of transmission networks over time. See Chapter 3 for more information about this review.

2.5.3 Climate change policy and the National Transmission Network Development Plan

Climate change policies may lead to changed inter-regional power flows as sources of low emission generation are exploited. This may increase the focus on interconnector capacities between regions. This changed focus, coupled with expected changes in generation configuration, will influence transmission network planning. As a result, the 2010 NTNDP will:

- use market modelling and system studies, based on a series of scenarios developed by AEMO in conjunction with stakeholders from the Australian Government Department of Resources, Energy and Tourism (DRET), and
- develop AEMO's view of an efficient transmission network development program for the NEM.

The scenarios include a range of fuel resource parameters and responses to environmental issues, which contribute to the pattern of generation and load development. The system studies are intended to reveal limitations in the current transmission system, which the proposed development program will address. AEMO has adopted a scenario approach across its planning documents. In the NTNDP, AEMO will use five scenarios to describe a particular potential market future, deriving from a combination of a range of drivers. Each NTNDP scenario is defined by a set of internally consistent economic and policy settings, estimates of generation technology, technology costs, and price-demand relationships.

2.6 Other investment issues

Arrangement involving the market, industry structure, and ownership arrangements can affect the generation investment environment. In addition, energy market governance arrangements and the broader regulatory and policy environment can influence market confidence and, in turn, investment.

2.6.1 Market structure and ownership

Market structure and ownership arrangements can have an impact on the degree of competition and market entry, the nature of commercial incentives for investors, and the degree of commercial risk.

Early government industry restructuring to introduce competition focussed on separating the functions of generation, transmission, and retail. In most cases, retailing was originally bundled with distribution. Under private market conditions, however, the NEM has seen on-going restructuring with a noticeable trend towards bundling retailing with generation into 'gen-tailers'. This has occurred as participants have recognised limited synergies between regulated network businesses and competitive retail businesses in the new market structure, and that such an ownership structure can aid in risk management.

To date, the degree of public-private ownership has varied across the NEM. From an overall NEM perspective, this implies that potential investors face different commercial incentives across regions. In Victoria, South Australia, and the Australian Capital Territory the industry has been private for almost a decade.

More recently, the Queensland Government privatised most of its unbundled retail assets, and the New South Wales Government has announced plans to sell or float its retailers and to sell rights to trade the output of its generators. Neither government has indicated an intention to sell their network assets. AEMO is not aware of any plans to sell Tasmanian or Snowy Hydro Limited assets.

2.6.2 The regulatory environment

Energy market governance arrangements and the regulatory environment can also affect investment decisions. Chapter 3 provides an overview of the regulatory environment in the NEM, and current and recent regulatory reviews relevant to investment decisions. The clear governance arrangements in the NEM and consistent national economic regulation should add to investor confidence.

Policy decisions external to the energy sector can also have a considerable effect on investor confidence. These policies range from climate change to tax arrangements, which are all under review.

Chapter 3 – NEM Governance and Recent Market Development

3.1 Summary

This chapter outlines the governance and legislative framework underpinning the operation of the National Electricity Market (NEM), and the functions and responsibilities of its governance institutions. It also presents the outcomes or status of current and recent reviews with the potential to affect the nature of generation or demand in the NEM. These reviews include the Prime Minister's Task Group on Energy Efficiency, and the Australian Energy Market Commission's (AEMC) Review of Energy Market Frameworks in Light of Climate Change Policies.

3.2 NEM governance and regulatory framework

This section outlines the governance and regulatory framework underpinning the NEM, including information about the National Electricity Law (NEL), the National Electricity Objective (NEO), and the National Electricity Rules (NER), and the roles and responsibilities of the Ministerial Council on Energy (MCE), the Australian Energy Market Operator (AEMO), the AEMC, and the Australian Energy Regulator (AER).

3.2.1 National Electricity Law

The NEM was established in 1998 and is a wholesale market through which generators and retailers trade electricity. The NEM comprises six participating jurisdictions that are linked by transmission networks: Queensland, New South Wales, the Australian Capital Territory, Victoria, Tasmania, and South Australia.

The NEL is a schedule to a piece of South Australian lead legislation, the National Electricity (South Australia) Act 1996, which is applied in other participating jurisdictions by application acts. The NEL and the NER compose the current regulatory framework governing the NEM. 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. The NER describes the day-to-day operations of the NEM and the framework for network regulation.

3.2.2 National Electricity Objective

The NEL includes a National Electricity Objective (NEO), which provides a single guiding principle for decision making under the NEL. The objective of the NEO '…is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to:

- price, quality, safety, reliability and security of supply of electricity; and
- the reliability, safety and security of the national electricity system.'

AEMO, the AEMC, and the AER must consider the NEO when performing their functions under the NEL and the NER. The NEO also guides the rule-making functions of the AEMC, and MCE statements of policy principles must be consistent with it.

3.2.3 National Electricity Rules

The NER has the force of law under Section 9 of the NEL, and is binding on all persons to whom it applies, including all participants and intending participants.

The AEMC is responsible for administering, reviewing, and publishing the NER in accordance with the NEL and must have regard to the NEO when performing its rule-making functions. The NER-change procedure is outlined in Section 91 of the NEL. The AEMC provides up-to-date information about all NER changes, amendments, and superseded versions on its website[8].

3.2.4 NEM governance institutions

The NEM is governed by a group of institutions, and Table 3.1 summarises their roles and responsibilities.

Table 3.1–Roles and responsibilities of NEM governance institutions

	Roles and responsibilities
Council of Australian Governments (COAG)	COAG comprises the Prime Minister, State Premiers, Territory Chief Ministers and the Australian Local Government Association President. Its role is to initiate, develop, and monitor the implementation of policy reforms that are nationally significant and that require cooperative action by Australian governments, including in relation to climate change and energy. Issues may arise from a number of sources, including: • Ministerial Council deliberations • international treaties that affect States and Territories, or • major initiatives of one government (particularly the Australian Government), which affect or require the cooperation of other governments.
Ministerial Council on Energy (MCE)	The MCE is a COAG council comprising Australian, State, and Territory Energy Ministers. Established in 2001, the MCE sets the national policy direction for the Australian energy sector and implements the COAG national energy policy framework. The MCE's objectives, as agreed by COAG, are to provide national: • policy development oversight and coordination to address the opportunities and challenges facing Australia's energy sector into the future, and • leadership so that consideration of broader convergence issues and environmental impacts are effectively integrated into energy sector decision making. In providing high-level direction to the AEMC on energy policy issues, the MCE may: • direct the AEMC to carry out a review and submit a report to the MCE • initiate NER-change proposals, including in response to an AEMC review • publish Statements of Policy Principles on any matter relevant to the exercise by the AEMC of its functions under the NEL or the NER, and • implement energy policy reforms as agreed by COAG.
Australian Energy Market Commission (AEMC)	Established as a statutory commission from 1 July 2005, the AEMC is responsible for rule-making and market development. The AEMC's responsibilities include: • administering, reviewing, and publishing the NER and National Gas Rules (NGR) in accordance with the NEL and National Gas Law (NGL) • considering and making determinations on proposed NER changes • undertaking reviews on its own initiative or as directed by the MCE, and • providing market development advice to the MCE on the energy market. The AEMC chairs the Reliability Panel, which includes representatives from AEMO, market customers, generators, transmission network service providers (TNSPs), distribution network service providers (DNSPs), and electricity customers. Clause 8.8.1 of the NER prescribes the Reliability Panel's functions.

[8] AEMC. Available at www.aemc.gov.au. Viewed June 2010.

	Roles and responsibilities
Australian Energy Regulator (AER)	Established as a statutory body from 1 July 2005, the AER enforces and monitors compliance with energy market legislation, and performs economic regulatory functions for the gas and electricity sectors. AER regulatory functions include: • monitoring and enforcing compliance with the NEL, NGL, NER, NGR, and National Electricity Regulations (South Australia), and • economic oversight of regulated electricity and gas transmission and distribution services in the NEM, as well as gas infrastructure in the Northern Territory.
Australian Energy Market Operator (AEMO)	AEMO is the independent market operator of the NEM and gas markets in the Eastern States. AEMO was established by COAG and commenced operation on 1 July 2009. AEMO is a company limited by guarantee. Its ownership is split between government (60%) and industry (40%). These arrangements will be reviewed in 2012. Six separate organisations that formerly operated Australian electricity and gas markets merged to form AEMO. These are the National Electricity Market Management Company (NEMMCO), the Victorian Energy Networks Corporation (VENCorp), the Electricity Supply Industry Planning Council (ESIPC), the Retail Energy Market Company (REMCO), the Gas Market Company, and the Gas Retail Market Operator. AEMO's electricity functions include: • operation and administration of the NEM • providing support system services for the retail electricity market in the regions: Queensland, New South Wales (including the Australian Capital Territory), Victoria, South Australia, and Tasmania. • planning and directing procurement of augmentations to the Victorian electricity Declared Shared Network (DSN) • providing planning advice for the South Australian electricity transmission system, and • acting as the National Transmission Planner for the NEM. AEMO's gas functions include: • operating and administering the declared wholesale market in Victoria, which includes being the sole body allowed under the NGL to submit gas rule changes for AEMC consideration • administering the gas retail markets for New South Wales, Queensland, South Australia, Victoria, and Western Australia (via subcontract) • planning the gas Declared Transmission System (DTS) in Victoria • operating the gas market bulletin board, and • establishing the Short-Term Trading Market (STTM) to operate in Sydney, Adelaide, and Queensland. In addition to these functions, AEMO assists with developing energy markets by identifying issues, conducting public consultations, and putting forward NER changes to the AEMC. The MCE may also direct AEMO to conduct specific market reviews.

3.3 Current policy and regulatory developments

This section focuses on the status or outcome of reviews or NER changes that, in AEMO's view, have the potential to affect the NEM's investment environment.

3.3.1 Carbon Pollution Reduction Scheme

In April 2010, the Australian Government announced a delay in the introduction of a Carbon Pollution Reduction Scheme (CPRS) until after the end of the current commitment period of the Kyoto protocol (end of 2012). In the interim, the Government announced that it will boost existing investments in clean and renewable energy and support greater energy efficiency measures to reduce greenhouse gas emissions in the short term.

3.3.2 Enhanced national Renewable Energy Target scheme

The Australian Government announced changes to the national Renewable Energy Target (RET) scheme in February 2010. Chapter 2 provides an overview of the RET, and discusses the scheme's impact on the NEM.

3.3.3 The Energy White Paper

In September 2008, the Australian Government established the Energy White Paper[9], which considered the requirements for meeting Australia's energy needs in the presence of carbon pricing and the national RET scheme. The Energy White Paper has since been deferred pending the resolution of climate change policy developments.

AEMO and the Energy White Paper Secretariat (Commonwealth Department of Resources, Energy and Tourism (DRET)) have collaborated on a set of market modelling scenarios to inform the final Energy White Paper and AEMO's National Transmission Network Development Plan (NTNDP). The scenarios roughly align with the economic growth scenarios outlined in the Electricity Statement of Opportunities (ESOO).

3.3.4 Prime Minister's Task Group on Energy Efficiency

In March 2010, the Prime Minister established the Task Group on Energy Efficiency to advise the Australian Government, by mid-2010, on options to improve Australia's energy efficiency by 2020. To provide further information and advice, the Government has also established an advisory group with experts from industry and non-government organisations.

The Task Group will deliver its recommendations to the Prime Minister through the Minister for Climate Change, Water and Energy Efficiency, and the Minister for Resources and Energy.

The Task Group's terms of reference[10] include recommending energy efficient mechanisms that:

- are economically and environmentally effective, and socially inclusive
- complement the Carbon Pollution Reduction Scheme (CPRS) and the national RET scheme, in line with COAG's Complementarity Principles
- build on, complement, inform, and improve the National Strategy for Efficient Energy (NSEE), but do not duplicate its efforts
- target known barriers to entry including (but not limited to) information asymmetries, split incentives, access to capital, technology risks, regulatory barriers, energy pricing, and behavioural barriers, and
- follow examinations of the impacts and interactions between proposed Australian carbon policies.

3.3.5 Review of Energy Market Frameworks in Light of Climate Change Policies

The AEMC's Review of Energy Market Frameworks in Light of Climate Change Policies concluded that energy market frameworks, supported by a number of recommended changes, are capable of accommodating the impacts of the proposed CPRS and the enhanced national RET scheme.

The MCE-directed review, which commenced in August 2008, assessed whether the existing energy market frameworks will cope with the implementation of the CPRS and the enhanced national RET scheme, and any amendments to the frameworks that may be required.

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[9] Department of Resources, Energy and Tourism. Energy White Paper. Available at http://www.ret.gov.au/ENERGY/FACTS/WHITE_PAPER/Pages/energy_white_paper.aspx. Viewed June 2010.

[10] Department of Climate Change and Energy Efficiency. Prime Minister's Task Group on Energy Efficiency: Terms of Reference. Available at http://www.climatechange.gov.au/en/government/submissions/pm-task-group/terms-reference.aspx. Viewed June 2010.

The review's conclusions, published in a Final Report to the MCE in September 2009[11], identified the need for change to existing frameworks in the following areas:

- The removal of retail price regulation where competition is found effective, and increased flexibility where retail price regulation remains.
- A more efficient regulatory framework for connecting clusters of new remote generation to energy networks.
- More cost-reflective charges for generators in respect of the efficient investment and use of the network.
- The introduction of new transmission charges to reflect the costs of investment required to allow electricity to flow efficiently between regions.

Several recommendations for NER changes were included in the Final Report for consideration, including a recommendation to introduce Scale Efficient Network Extensions (SENEs) to facilitate the connection of multiple, remotely-located generators to the transmission network (see Chapter 2). The final NER determination is now expected by 3 February 2011.

Transmission Frameworks Review

On 20 April 2010, the Ministerial Council on Energy (MCE) directed the AEMC to conduct a review of the arrangements for the provision and utilisation of electricity transmission services in the NEM, with a view to ensuring that the incentives for generation and network investment and operating decisions are effectively aligned to deliver efficient overall outcomes.

In accordance with the Terms of Reference[12], the AEMC is to review the role of transmission in providing services to the competitive sectors of the NEM, by holistically considering the following key areas:

- Transmission investment
- network operation
- network charging, access and connection, and
- management of network congestion.

The review stems from the AEMC's Review of Energy Market Frameworks in Light of Climate Change Policies, which recommended that further work be undertaken in relation to the efficient provision and utilisation of the transmission network. The recommendation reflected the AEMC's finding that climate change policies will fundamentally change the utilisation of transmission networks over time, both between and within regions of the NEM, and that this will place stress on existing market frameworks.

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[11] Australian Energy Market Commission. Final Report for the Review of Energy Market Frameworks in Light of Climate Change Policies. Available at http://www.aemc.gov.au/Media/docs/Review%20Final%20Report-9f02959f-0446-48ba-89a1-5882d58e11fd-0.PDF. Viewed June 2010.

[12] Ministerial Council on Energy. Terms of Reference for the Transmission Frameworks Review. April 2010. Available at http://www.aemc.gov.au/Media/docs/MCE%20Terms%20of%20Reference-d4e720b4-c8a7-4ea8-a7a6-d1eba122c6c2-0.PDF

3.3.6 Review of Demand-Side Participation in the NEM

In December 2009, the AEMC completed Stage 2 of a review of the role of demand-side participation (DSP) in the NEM, which sought to identify whether there are barriers or disincentives within the NER that inhibit the efficient use of DSP.

The AEMC concluded that in the context of current technological, pricing, and demand conditions, the NER does not inhibit the efficient use of DSP, and there are a number of opportunities to improve the NER to enhance DSP in the market.

Incorporating several proposed NER changes, the Stage 2 Final Report[13] also outlined issues for consideration in a third stage, involving a number of prospective developments, such as smart grids and smart meters, which are likely to increase the scope for more active DSP. The third stage of the review is expected to commence in mid-2010.

In conjunction with any final NER determinations, the implementation of the review's recommendations may see a greater focus on demand management, with decreased energy demand and a reduced need for investment in both distribution and transmission infrastructure.

3.3.7 The National Energy Customer Framework

The National Energy Customer Framework (NECF) is intended to streamline energy distribution and retail regulatory functions in a national framework, and develop a more efficient national retail energy market with appropriate consumer protection. The framework aims to make retail market investment more accessible and easier to navigate.

To be introduced in 2011, the NECF package comprises several legislative and framework changes for the gas and electricity markets. Specifically, it contains a proposed National Energy Retail Law (NERL), National Energy Retail Regulations, National Energy Retail Rules (NERR), and proposed new parts to the gas and electricity rules under the National Gas Law (NGL) and the NEL.

The package primarily addresses:

- the retailer-customer relationship and associated rights, obligations, and consumer protection measures
- distributor interactions with customers and retailers, and associated rights, obligations, and consumer protection measures
- retailer authorisations, and
- compliance monitoring and reporting, enforcement, and performance reporting.

In accordance with the Australian Energy Market Agreement (AEMA)[14], the AEMC will be the rule-making body for the NERR, with the initial NERR to be made by the South Australian Energy Minister under powers in the NERL. The AER and AEMC are already the regulator and rule-making body, respectively, in relation to the NER and the NGR.

[13] Australian Energy Market Commission. Final Report for Stage 2 of the Review of Demand-Side Participation in the National Electricity Market. Available at http://www.aemc.gov.au/Market-Reviews/Open/Review-of-Demand-Side-Participation-in-the-National-Electricity-Market.html. Viewed June 2010.

[14] Department of Resources, Energy and Tourism. Australian Energy Market Agreement. Available at, http://www.ret.gov.au/Documents/mce/_documents/IGA_FINAL_%2830JUNE2004%292004071310032320041112162849.pdf. Viewed June 2010.

A final legislative package is expected to enter the South Australian Parliament in early September 2010 (South Australia being the lead legislator), with Application Acts to be introduced in each participating jurisdiction from January 2011. Each jurisdiction's Application Act will then set out the specific jurisdictional arrangements, including the timeline for transitioning to the NECF.

3.3.8 The Energy Market Prudential Readiness Review

The Energy Market Prudential Readiness Review is an examination of the adequacy and appropriateness of the settlement and prudential risk management arrangements used in the NEM and in the administered gas markets.

The review's objective is to ensure the prudential regimes AEMO administers in all energy-related markets are robust and effective, and can support ongoing investment in the NEM and gas markets in light of structural changes, and investment and operating environment shifts. The review's outcomes are likely to increase efficiency and promote competition and investment in the NEM.

According to the Terms of Reference[15], AEMO has been asked to report to the MCE by late November 2010.

3.3.9 The Reliability Panel's Review of the Reliability Standard and Settings

In April 2010, the Reliability Panel provided its biennial report[16] to the AEMC on the Review of the Reliability Standard and Settings, which reviewed the Market Price Cap (MPC), price floor, and Cumulative Price Threshold (CPT). These price settings provide important signals to attract investment in the NEM's energy-only market.

The Reliability Panel recommended retention of an MPC of $12,500/MWh (which will come into effect on 1 July 2010), indexed according to the Producer Price Index. The Panel also recommended that the market price floor be maintained at -$1,000/MWh, while the CPT should be increased from $187,500/MWh annually according to the same index applied to the MPC.

The outcomes of this review have direct consequences for investment in the NEM. See Chapter 6 for information about how the ESOO has considered these outcomes.

3.3.10 AEMC Review of the Effectiveness of NEM Security and Reliability Arrangements in Light of Extreme Weather Events

The AEMC is carrying out a review of the effectiveness of NEM security and reliability arrangements in light of extreme weather events. In the context of extreme weather events such as droughts, heatwaves, storms, floods and bushfires, the MCE has directed the AEMC to:

- examine the current arrangements for maintaining the security and reliability of supply to end users of electricity, and provide a risk assessment of the capability of those arrangements to maintain adequate, secure and reliable supplies

[15] Australian Energy Market Operator. Energy Market Prudential Readiness Review. Available at http://www.aemo.com.au/electricityops/prudential_review.html. Viewed June 2010.

[16] Australian Energy Market Commission. Final Report for the Review of Reliability Standards and Settings. Available at http://www.aemc.gov.au/Media/docs/Final%20Report%20-%20Reliability%20Standard%20and%20Settings%20Review-c3994458-70b3-4d66-badd-dc7e8b809f68-1.PDF. Viewed June 2010.

- provide advice on the effectiveness of, and options for, cost-effective improvements to current security and reliability arrangements, and
- identify, if appropriate, any cost-effective changes to the market frameworks that may be available to mitigate the frequency and severity of threats to the security and reliability of the power system.

Following the release of the first interim report[17] and a public consultation on a second interim report[18] and a consultation paper[19] (published on 2 March 2010), the AEMC delivered a final report to the MCE on 31 May 2010. The MCE will determine whether this report will be made publicly available.

3.3.11 Minimising barriers to cost-effective small generator participants in the NEM

Since December 2009, AEMO has been reviewing how best to minimise barriers to cost-effective small generator participation in the NEM. Small generators, also known as distributed or embedded generators, are defined as generators eligible for an exemption from registration with AEMO.

The review seeks to identify issues surrounding small generator participation in the NEM and other related markets. In particular, the scope includes an assessment of whether current arrangements realise the potential value of small generators in the NEM, and an exploration of views on a range of matters related to integrating small generation into the NEM more efficiently.

The outcomes of this review may be of particular importance in light of climate change policies, which have encouraged a move towards new renewable generation that may enter the market, initially on a smaller scale. The outcomes should result in an increased ability for small generators to access and invest in the NEM.

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[17] Australian Energy Market Commission. Interim Report - Review of the Effectiveness of NEM Security and Reliability Arrangements in light of Extreme Weather Events. 29 May 2009. Available at http://www.aemc.gov.au/Media/docs/1st%20Interim%20Report-07b5d46e-0aad-4880-a82f-71416e680dda-0.PDF. Viewed June 2010.

[18] Australian Energy Market Commission. Second Interim Report - Review of the Effectiveness of NEM Security and Reliability Arrangements in light of Extreme Weather Events. 18 December 2009. Available at http://www.aemc.gov.au/Media/docs/Review%20Second%20Interim%20Report-4721eba1-87b4-4595-80c8-733ec801cdb4-0.PDF. Viewed June 2010.

[19] Australian Energy Market Commission. Consultation Paper - Review of the Effectiveness of NEM Security and Reliability Arrangements in light of Extreme Weather Events. 2 March 2010. Available at http://www.aemc.gov.au/Media/docs/AEMC%20Consultation%20Paper-4e93a469-d8a7-4c8b-b5f6-9958c9f34a92-0.PDF. Viewed June 2010.

3.4 2009 ESOO market development updates

This section updates some of the market development information from the 2009 ESOO.

3.4.1 Energy Adequacy Assessment Projection

AEMO has released the first Energy Adequacy Assessment Projection (EAAP)[20], following the publication of a set of EAAP guidelines[21]. The development of the guidelines (reported in last year's ESOO), followed a NER determination on Clause 4.7C, which requires AEMO to perform a regular assessment of the impact of energy-limited generation on the reliability of the NEM. The purpose of the EAAP is to provide market participants and other interested persons with an analysis that quantifies the impact of energy constraints on energy availability over a 24-month period under a range of scenarios.

The first EAAP report, published on 31 March 2010, covered the period 1 April 2010 to 31 March 2012, and found that the Reliability Standard:

- will be met in all regions during the period April 2010 to March 2012 under the average rainfall scenario
- will be met in all regions during the period April 2010 to March 2011 under low rainfall scenarios, and
- will only be met in the Queensland, New South Wales, South Australian, and Tasmanian regions during the period April 2011 to March 2012 under the low rainfall scenario.

In accordance with the NER, AEMO will publish the EAAP quarterly from March 2010.

3.4.2 Feed-in Tariff Schemes

On 29 November 2008, COAG released a climate change communiqué[22] notifying of an agreement to:

- a set of national principles to apply to new Feed-in Tariff Schemes, and
- inform the reviews of existing schemes.

These principles aim to promote consistency between schemes across Australia.

The final report on the implementation of the national principles for feed-in tariffs was received in October 2009 and provided to the MCE for its consideration in December 2009. The MCE has tasked officials with developing a policy position for consideration by the MCE at their next scheduled meeting around the middle of 2010.

More information on Feed-in Tariff Schemes can be found on the MCE website, and various State and Territory Government websites where feed-in tariffs have already been introduced.

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[20] Australian Energy Market Operator. Energy Adequacy Assessment Projection Report. Available at http://www.aemo.com.au/corporate/0400-0008.pdf. Viewed June 2010.

[21] Australian Energy Market Operator. Energy Adequacy Assessment Projection Guidelines. Available at http://www.aemo.com.au/electricityops/408-0001.html. Viewed June 2010.

[22] Council of Australian Governments - Communique - 29 Nov 2008. Available at http://www.coag.gov.au/coag_meeting_outcomes/2008-11-29/. Viewed June 2010.

3.4.3 Wind generation forecasting

In May 2007, a project to develop an Australian Wind Energy Forecasting System (AWEFS) was introduced. As reported in the 2009 ESOO, the base package was implemented in AEMO's IT systems in November 2008, and is used to forecast wind generation for all NEM forecast timeframes (5-minute dispatch, 5-minute pre-dispatch, pre-dispatch, ST PASA, and MT PASA). AWEFS provides forecasts for all wind farms with a capacity equal to or greater than 30 MW.

In June 2010, further enhancements to the base package were implemented. These included system improvements such as scalability, redundancy, SCADA-based extreme events alarming, user rights management, and improvements in system supervision.

Chapter 4 - Energy and Demand Projections

4.1 Summary

This chapter presents the energy and maximum demand (MD) projections used to develop the supply-demand outlook. These projections are based on projections previously published in the annual planning reports (APRs) for each region and the South Australian Supply and Demand Outlook (SASDO)[23,24,25,26,27]. The ESOO's projections may differ slightly from the projections presented in the source planning reports, as the reference points have been aligned to place the projections on the same basis. See Attachment 1 for more information about the underlying policy assumptions and economic growth forecasts used to develop the projections.

The energy and MD projections in the short run are generally higher than the projections presented in the 2009 ESOO. This chiefly reflects the fact that the economic downturn in 2009/10 was milder and recovery from the global financial crisis was faster than expected.

The long-run projections are based on long-run economic growth forecasts, renewable energy targets, and carbon price trajectories that are similar to the 2009 ESOO, although the implementation of an emissions trading scheme is now assumed to be delayed until 2013/14.

See Appendix A for the regional 10% POE energy and MD projections supplied by scheduled and semi-scheduled generating units, and the winter and summer demand coincidence factors for each region. See Appendix B for information about the energy and MD projection assessment.

4.2 Key definitions of energy and demand

4.2.1 Energy and maximum demand definitions

This section provides an overview of the key definitions and commonly used terms within the electricity supply industry relating to electricity supply and MD. These explanations play an important part in terms of understanding the energy and MD projections presented in this chapter. See Section 4.11 for more information about the underlying technical assumptions used to develop the projections.

[23] TransGrid. New South Wales Annual Planning Report. 2010.

[24] Australian Energy Market Operator. Victorian Annual Planning Report. 2010.

[25] Powerlink. Queensland Annual Planning Report. 2010.

[26] Transend. Tasmanian Annual Planning Report. 2010.

[27] Australian Energy Market Operator. South Australian Supply and Demand Outlook. 2010.

Supply and demand

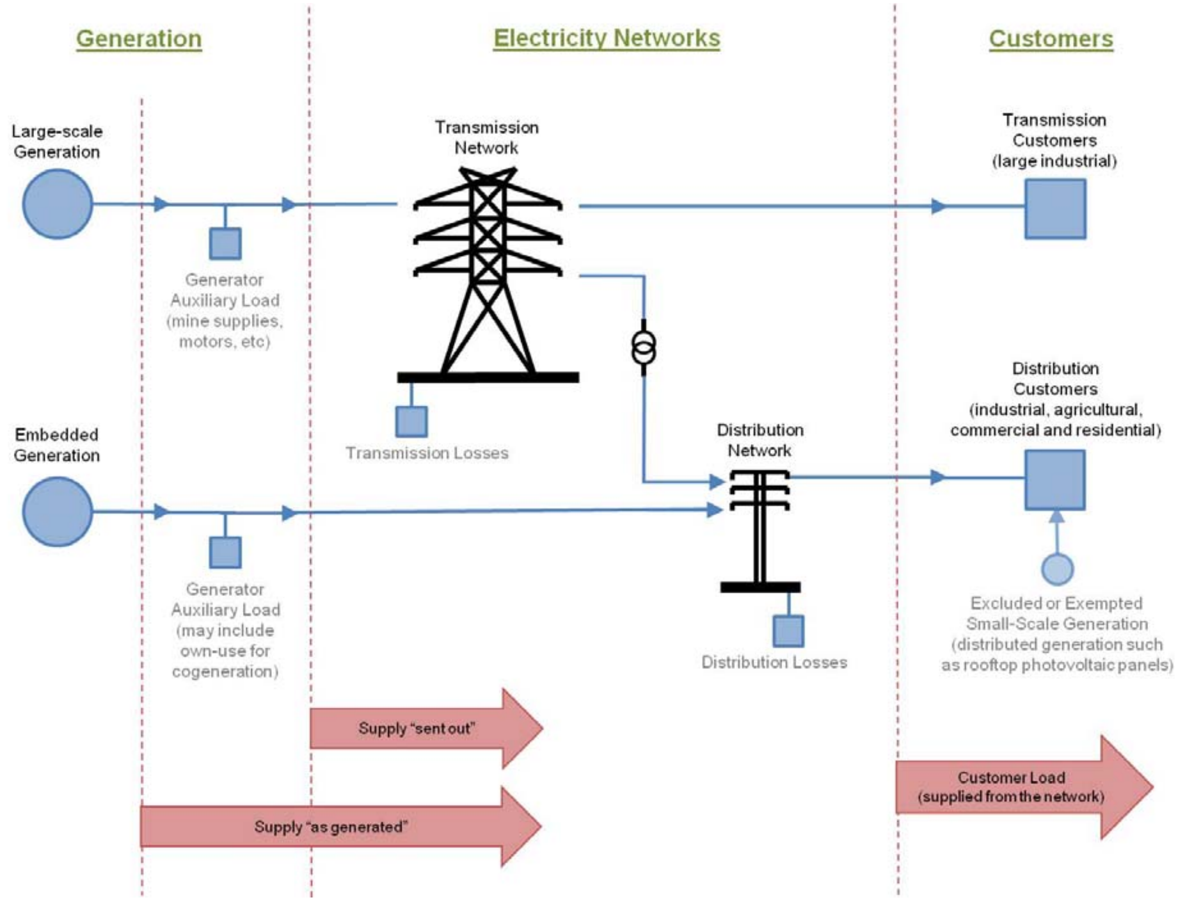
Electricity supply is instantaneous, which means it cannot be stored, and supply must equal demand at all times. The National Electricity Market (NEM) provides a central dispatch mechanism that adjusts supply, with the dispatch of generation every five minutes to meet demand.

Measuring demand by measuring supply

Electricity demand is measured by metering what is being supplied to the network rather than what is being consumed. The benefit of measuring demand this way is that it automatically includes not only the electricity used by customers, but also the energy lost transporting the electricity (network losses), as well as the electricity used by the generators themselves to generate the electricity (auxiliary loads).

Figure 4-1 shows the high level topology of the electricity network connecting supply (generation) and demand (customers). It also shows the different points at which supply and demand are measured as well as the relative contribution different types of generation make.

Figure 4-1—Electricity network topology



The basis for measuring demand

The electricity (energy) supplied by a generator can be measured one of two ways:

- Supply 'as-generated' is measured at the generator terminals. This measures the entire output from a generator.

- Supply 'sent-out' is measured at the generator connection point. This only measures the electricity supplied to the market and excludes a generator's auxiliary loads.

The basis for projecting energy and MD

The ESOO energy and MD projections are presented in the following way:

- Energy is presented on a **sent-out** basis. This means that the energy projections include the customer load (supplied from the network) and network losses, but not the auxiliary loads.
- MD is presented on an **as-generated** basis. This means that the MD projections (the highest level of instantaneous demand for electricity during summer and winter each year, averaged over a 30-minute period) include the customer load (supplied from the network), the network losses, and the auxiliary loads.

Categorising generation

Generation types are categorised differently. This enables an accurate assessment of the contribution from different types of generation when it comes to analysing the markets and assessing the supply-demand outlook.

Figure 4-1 shows a high-level representation of the three basic types of generation connected to the electricity network:

- Large-scale generation includes any generating system above 30 MW that offers its output for control by the NEM dispatch process.
- Embedded generation includes any generating system installed within a distribution network or by industry to meet its own electricity needs. Depending on how it is implemented, embedded generation above 30 MW can be offered for control by the NEM dispatch process.
- Exempt, small-scale generation, or distributed generation, includes generation installed by customers, including, for example, some relatively large generators that may be located on customers' premises, back-up generators that rarely run, roof-top photovoltaics, micro generation from fuel cells, landfill generators, small cogeneration, and very small wind farms.

In terms of these three basic generation types, generation is further categorised in terms of the NEM dispatch process and registration:

- Scheduled generation typically includes conventional generation (fuelled from coal, gas or hydro) with a capacity greater than 30 MW. The output from scheduled generation is controlled by the NEM dispatch process.
- Semi-scheduled generation is a recent category catering for intermittent generation (from the wind or the sun) with a capacity greater than 30 MW. The output from semi-scheduled generation can be limited by the NEM dispatch process.
- Non-scheduled generation is a category of conventional or intermittent generation that is not controlled by the NEM dispatch process. This generally includes generation from 5 MW-30 MW, but some existing non-scheduled generation is larger (for example, older wind farms and run of river hydro). The ESOO projections include the output from all significant non-scheduled generating units (as nominated by the jurisdictional planning bodies (JPBs)) in the measures of non-scheduled energy and MD.
- Exempt generation is typically smaller generation with a capacity less than 5 MW that is not required to register with AEMO or participate in the NEM dispatch process. Typically, exempt generation is operated by customers to offset their load and is not separately metered.

An increasingly important part of the electricity supply involves this last category of exempt, small-scale distributed generation.

Small-scale distributed generation

Figure 4-1 shows the role that small-scale distributed generation plays in terms of the network. Attaching to distribution customers, small-scale distributed generation reduces (or offsets) the amount of electricity that needs to be supplied by large-scale generation.

The projections are developed with the knowledge that some demand is supplied by small-scale distributed generation, as well as off-grid supply to remote customers. This type of supply is effectively unmeasured in its own right and is aggregated with the local demand. In terms of the MD projections, this category of generation is identified as excluded generation.

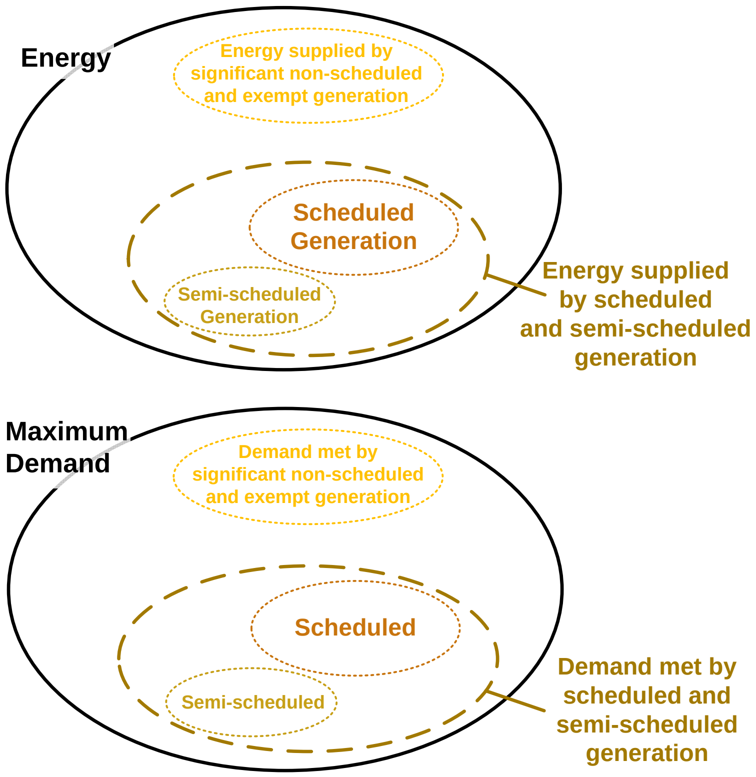
The projections do, however, indirectly account for this type of generation. For example, a large increase in household roof-top photovoltaics is reflected in lower projected growth. Similarly, energy efficiency and load control initiatives act to reduce the demand at customer locations. In the projections this will be apparent as a lower demand growth projection.

From the NEM's perspective, it is sometimes difficult to separate the contributions to reduced growth rates from increased local generation, improvements in energy efficiency, and customers controlling their loads at times of high prices. This difficulty increases when the activities occur in a more widespread manner right down to household levels. The more widespread use of 'smart' meters may improve the ability to discern what is happening at these consumer locations.

4.2.2 The components of energy and maximum demand in NEM forecasting

Figure 4-2 shows the components of energy and MD, which represent the various generation categories being accounted for by the projections.

Figure 4-2—The components of energy and maximum demand



Calculating energy and maximum demand

The energy projections account for the sent-out energy from scheduled, semi-scheduled, and significant non-scheduled and exempt generation. Calculating the amount of energy supplied by generation controlled by the NEM dispatch process (shown in Figure 4-2) requires subtracting the energy supplied from significant non-scheduled and exempt generation. To enable this analysis, Section 4.9 includes the non-scheduled energy projections for each region.

The MD projections account for the as-generated MD supplied from scheduled, semi-scheduled, and significant non-scheduled and exempt generation. Calculating the MD supplied by generation controlled by the NEM dispatch process requires subtracting the MD met by significant non-scheduled and exempt generation.

In other words, to calculate the demand met by generation controlled by the NEM dispatch process requires subtracting the demand met by significant non-scheduled generation from total demand.

When establishing the adequacy of NEM generation supplies, both the supply-demand outlook and the market tool, MT PASA, make assessments based on the demand met by generation controlled by the NEM dispatch process.

In the 2009 ESOO, total demand was referred to as native demand, and the demand controlled by the NEM dispatch process was referred to as scheduled and semi-scheduled demand.

See Section 4.9 for information about the projections of energy and MD supplied by non-scheduled and exempt generation.

Accounting for demand-side participation

Demand-side participation (DSP), which occurs when customers vary their consumption in response to changed market conditions, is treated as demand that does not need to be met by generation. As a result, DSP effectively occupies a separate part of the supply and demand equation, with its own set of projections (see Section 4.10).

In the supply-demand outlook, DSP acts to reduce the amount of generation needed to meet projected MD.

Defining the probability of exceedence

A probability of exceedence (POE) refers to the likelihood that an MD projection will be met or exceeded. The various probabilities (generally 90%, 50% and 10%) provide a range of likelihoods that analysts can use to determine a realistic range of power system and market outcomes.

The MD in any year will be affected by the weather conditions, and an increasing proportion of demand is sensitive to, for example, temperature and humidity conditions. In an average year, the expectation is that the 50% POE MD will occur. In an extreme season, expected to occur one year in ten, the 10% POE MD can occur. In a mild season, occurring one year in ten, the MD can be as low as the 90% POE projection.

With recent experiences with extreme weather, AEMO has also investigated 5% POE MD in some regions. These have been used, for example, in the calculation of the minimum reserve levels (MRLs) and reflect the conditions that may be expected one year in twenty[28].

[28] http://www.aemo.com.au/electricityops/mrl.html.

4.2.3 Changes since the 2009 ESOO

Table 4-1, Table 4-2, and Table 4-3 summarise the changes in the medium economic growth energy and MD projections since the 2009 ESOO. Last year's expectation of a more severe economic downturn has resulted in higher projected Australian economic growth in the immediate future. The medium economic growth projections for the 10-year outlook this year, however, are generally lower. Growth will also continue to be unevenly distributed across different regions. Given that there is no single national factor driving changes in the energy and MD projections since 2009, there is a mix of positive and negative changes.

Table 4-1—Energy projection changes since the 2009 ESOO

Region	Change in 2010/11 (GWh)	Change in 2018/19 (GWh)	Change in average growth rate (%)
Queensland	-190	+5,275	+0.8
New South Wales	+1,690	+2,605	+0.2
Victoria	+1,059	-44	-0.3
South Australia	-361	-1,575	-0.9
Tasmania	+369	+22	-0.3

Table 4-2—Summer 10% POE maximum demand projection changes since the 2009 ESOO

Region	Change in 2010/11 (MW)	Change in 2018/19 (MW)	Change in average growth rate (%)
Queensland	-11	+784	+0.7
New South Wales	-9	+192	+0.1
Victoria	+81	+133	0.0
South Australia	-10	-250	-0.7
Tasmania	+33	-15	-0.3

Table 4-3—Winter 10% POE maximum demand projection changes since the 2009 ESOO

Region	Change in 2011 (MW)	Change in 2019 (MW)	Change in average growth rate (%)
Queensland	-275	+807	+1.2
New South Wales	+41	+356	+0.2
Victoria	+144	+160	0.0
South Australia	-80	-300	-0.8
Tasmania	-53	-99	-0.2

4.3 NEM energy and maximum demand projections

This section presents energy and MD projections for the NEM as a whole. The energy projections represent the sum of all the regional values. The MD projections are the scaled-down sum of the regional projections.

The scaling of the projections represents the overall time diversity between MDs in different regions. The diversity factors represent the average diversity between the regions over the last five seasons, and are calculated to be 0.91 for summer and 0.98 for winter.

4.3.1 Energy

Table 4-4 presents recent actual and medium, high, and low energy projections for the NEM. Energy is projected to increase over the next 10 years at an annual average rate of:

- 2.1% under the medium growth scenario, and
- 3.4% and 1.1% under the high and low growth scenarios, respectively.

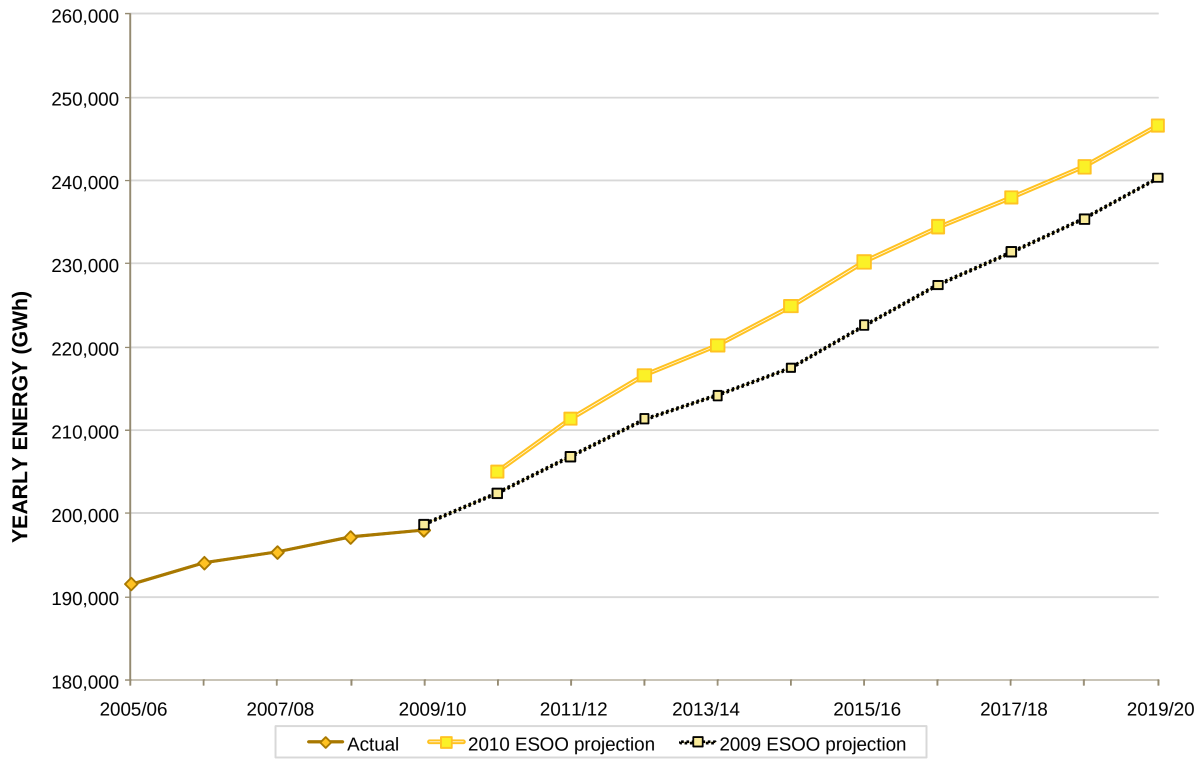
Table 4-4—NEM-wide energy projections (GWh)

Financial year	Actual	Medium growth	High growth	Low growth
2004/05	186,246			
2005/06	191,598			
2006/07	194,107			
2007/08	195,376			
2008/09	197,187			
2009/10 (estimate)	198,055			
2010/11		205,034	208,081	202,215
2011/12		211,405	217,566	204,929
2012/13		216,623	225,197	207,510
2013/14		220,167	231,613	209,570
2014/15		224,961	239,732	212,139
2015/16		230,248	249,022	214,903
2016/17		234,455	256,070	216,615
2017/18		237,935	261,925	218,923
2018/19		241,661	273,780	220,691
2019/20		246,584	281,915	224,000
Average annual growth	1.2%	2.1%	3.4%	1.1%

The pattern of projected energy growth is consistent with strong recent and projected Australian economic growth. As outlined in Attachment 1, the Australian economy is expected to be driven in the medium term by strong export volumes and prices, the construction sector and private consumption. This will particularly favour strong energy growth in regions with strong mining sectors such as Queensland.

Figure 4-3 compares the medium growth energy projections for the 2010 and 2009 ESOOs. The latest projection is approximately 6,000 GWh higher by 2020 than last year's projection. This is largely because the economic downturn associated with the global financial crisis was milder than expected and therefore there was less of a setback to economic growth in 2010/11.

Figure 4-3—Comparison of NEM-wide medium economic growth energy projections (GWh)



4.3.2 Maximum demand

Table 4-5 and Table 4-6 present actual and projected summer and winter MD projections for the NEM. The 90%, 50% and 10% POE MD projections are shown for each of the medium, high, and low growth scenarios.

The summer 10% POE MD is projected to increase over the next 10 years at an annual average rate of:

- 2.6% under the medium growth scenario, and
- 3.5% and 1.9% under the high and low growth scenarios, respectively.

The winter 10% POE MD is projected to increase over the next 10 years at an annual average rate of:

- 2.5% under the medium growth scenario, and
- 3.5% and 1.5% under the high and low growth scenarios, respectively.

The energy and MD data taken together show a declining average NEM summer load factor in recent years, with an implied projection that the ratio of average demand to maximum demand will plateau at just over 0.6 over the next 10 years. This reflects:

- recent increases in high but relatively infrequent cooling loads in the mainland regions, and
- an expectation that the equipment installation that underlies these increases has now resulted in near-saturation levels of air-conditioning capacity.

The implied average winter load factor also displays a variable historical pattern but is projected to remain above 0.6.

Table 4-5—NEM-wide summer maximum demand projections (MW)

Summer	Actual	90% POE			50% POE			10% POE		
		Medium	High	Low	Medium	High	Low	Medium	High	Low
2004/05	29,039									
2005/06	31,376									
2006/07	32,192									
2007/08	32,371									
2008/09	35,322									
2009/10	34,451									
2010/11		34,064	34,453	33,649	35,927	36,336	35,513	38,236	38,642	37,808
2011/12		35,160	35,860	34,419	37,134	37,836	36,348	39,494	40,226	38,694
2012/13		36,114	37,158	35,053	38,129	39,207	37,034	40,601	41,747	39,459
2013/14		37,193	38,607	35,805	39,289	40,766	37,871	41,747	43,248	40,283
2014/15		38,131	39,940	36,379	40,355	42,219	38,549	42,873	44,830	41,019
2015/16		39,192	41,368	36,999	41,427	43,681	39,171	44,119	46,472	41,778
2016/17		40,126	42,710	37,551	42,410	45,073	39,773	45,200	47,959	42,430
2017/18		41,012	43,948	38,319	43,398	46,434	40,609	46,182	49,374	43,299
2018/19		41,809	45,558	38,871	44,217	48,087	41,196	47,182	51,224	44,035
2019/20		42,734	46,887	39,481	45,218	49,513	41,900	48,232	52,724	44,759
Average annual growth	3.5%	2.6%	3.5%	1.8%	2.6%	3.5%	1.9%	2.6%	3.5%	1.9%

Table 4-6—NEM-wide winter maximum demand projections (MW)

Winter	Actual	90% POE			50% POE			10% POE		
		Medium	High	Low	Medium	High	Low	Medium	High	Low
2005	31,281									
2006	31,851									
2007	33,544									
2008	34,998									
2009	32,595									
2010		34,002	34,419	33,688	34,763	35,176	34,455	35,596	36,008	35,277
2011		34,791	35,593	34,108	35,572	36,379	34,880	36,426	37,247	35,700
2012		35,826	36,977	34,695	36,614	37,795	35,469	37,498	38,690	36,314
2013		36,791	38,502	35,387	37,603	39,341	36,189	38,504	40,270	37,047
2014		37,813	40,037	36,043	38,661	40,901	36,855	39,591	41,854	37,728
2015		38,456	41,137	36,302	39,323	42,045	37,137	40,256	43,025	38,020
2016		39,857	43,102	37,153	40,736	44,039	37,992	41,696	45,042	38,897
2017		40,823	44,567	37,793	41,714	45,524	38,641	42,710	46,559	39,549
2018		41,620	45,995	38,319	42,538	46,987	39,169	43,547	48,040	40,106
2019		42,455	47,389	38,744	43,389	48,407	39,605	44,421	49,511	40,568
2020		43,377	48,890	39,303	44,341	49,947	40,159	45,386	51,068	41,103
Average annual growth	1.0%	2.5%	3.5%	1.6%	2.5%	3.5%	1.5%	2.5%	3.5%	1.5%

Figure 4-4 and Figure 4-5 compare the summer and winter medium growth 50% and 10% POE projections for the 2010 and 2009 ESOOs. The 10% POE projections are:

- 105 MW higher for the 2010/11 summer
- 1,070 MW higher for the 2018/19 summer
- 220 MW lower for the 2011 winter, and
- 1,097 MW higher for the 2019 winter.

When compared to last year, the generally higher endpoints for the 2010 MD projections are consistent with the higher energy projections, which in turn reflect stronger projected levels of economic activity.

Figure 4-4—Comparison of NEM-wide medium economic growth summer maximum demand projections (MW)

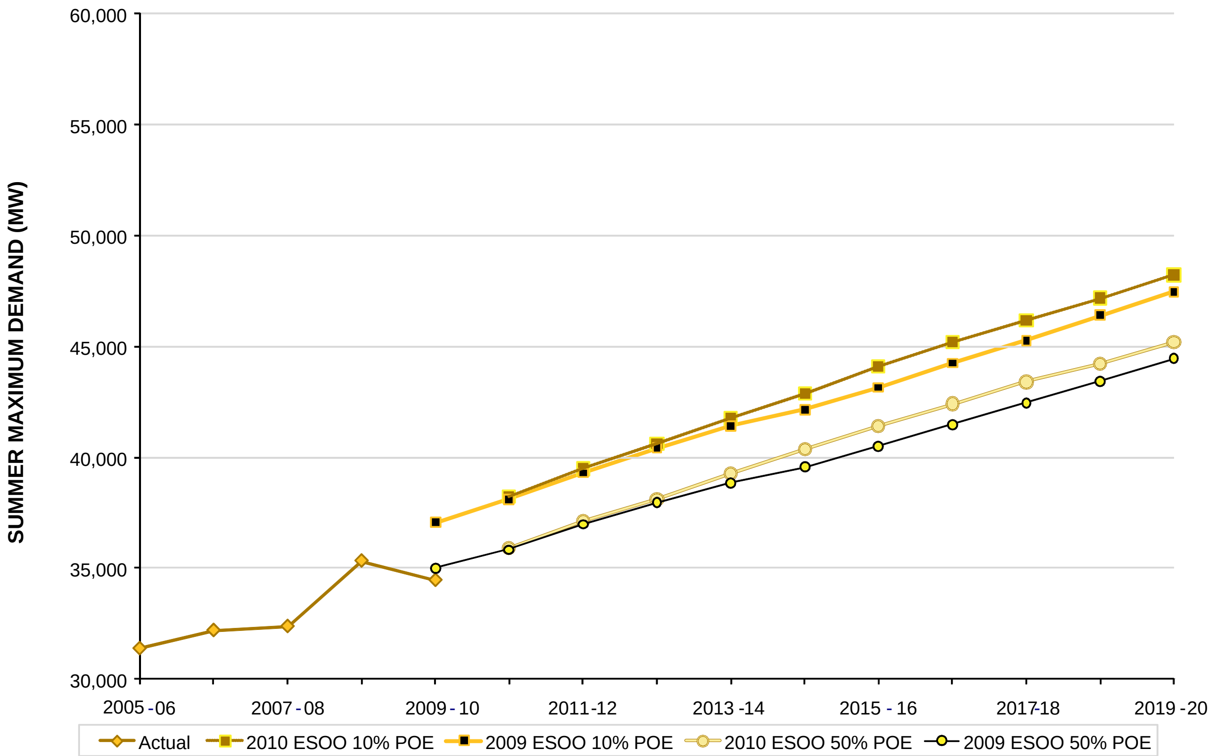
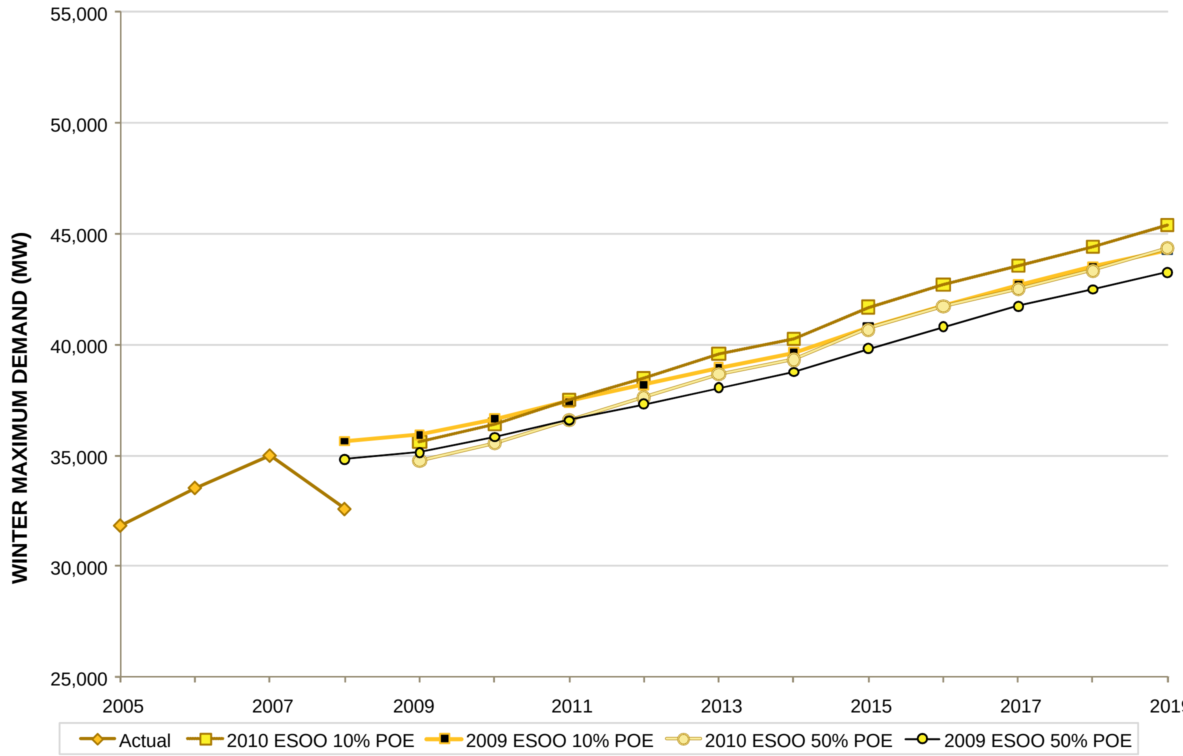


Figure 4-5—Comparison of NEM-wide medium economic growth winter maximum demand projections (MW)



4.4 Queensland

Powerlink Queensland provided the energy and MD projections and supporting information for Queensland. This information is consistent with the 2010 Queensland Annual Planning Report.

4.4.1 Energy

Table 4-7 presents the recent actual energy and medium, high, and low economic growth scenario energy projections for Queensland. Energy is projected to increase over the next 10 years at an annual average rate of:

- 3.9% under the medium growth scenario, and
- 6.7% and 1.7% under the high and low growth scenarios, respectively.

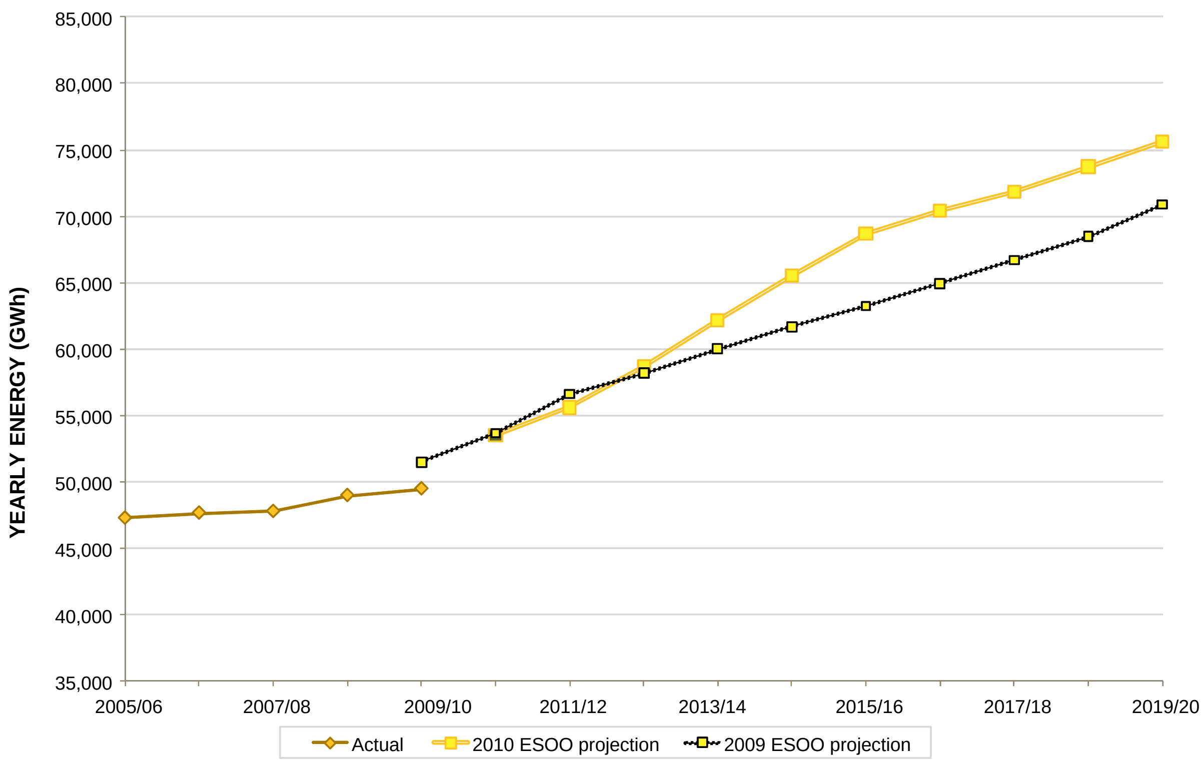
Table 4-7—Queensland energy projections (GWh)

Financial year	Actual	Medium growth	High growth	Low growth
2004/05	45,552			
2005/06	47,272			
2006/07	47,649			
2007/08	47,778			
2008/09	48,972			
2009/10 (estimate)	49,477			

Financial year	Actual	Medium growth	High growth	Low growth
2010/11		53,487	55,475	51,672
2011/12		55,601	59,400	52,378
2012/13		58,733	63,855	53,698
2013/14		62,182	69,026	55,373
2014/15		65,510	74,044	56,366
2015/16		68,657	79,510	57,250
2016/17		70,425	83,353	57,720
2017/18		71,851	86,939	58,932
2018/19		73,729	95,218	59,573
2019/20		75,606	99,389	60,278
Average annual growth	1.7%	3.9%	6.7%	1.7%

Figure 4-6 compares the medium growth projections for the 2010 and 2009 ESOOs. The latest energy projection is similar to last year's, but higher medium-term growth results in an energy level approximately 5,000 GWh higher by 2020 than last year's projection. This is due to an expected increase in demand in the Surat Basin area due to coal seam gas and coal mining developments, together with the establishment of support infrastructure and services.

Figure 4-6—Comparison of Queensland medium growth energy projections (GWh)



4.4.2 Maximum demand

Table 4-8 and Table 4-9 present actual and projected summer and winter MD projections for Queensland.

The summer 10% POE MD is projected to increase over the next 10 years at an annual average rate of:

- 4.1% under the medium growth scenario, and
- 6.1% and 2.3% under the high and low growth scenarios, respectively.

The winter 10% POE MD is projected to increase over the next 10 years at an annual average rate of:

- 4.2% under the medium growth scenario, and
- 6.7% and 1.7% under the high and low growth scenarios, respectively.

Table 4-8—Queensland summer maximum demand projections (MW)

Summer	Actual	90% POE			50% POE			10% POE		
		Medium	High	Low	Medium	High	Low	Medium	High	Low
2004/05	8,176									
2005/06	8,280									
2006/07	8,673									
2007/08	8,177									
2008/09	8,812									
2009/10 (estimate)	9,070									
2010/11		9,702	9,939	9,497	10,012	10,258	9,800	10,524	10,783	10,300
2011/12		10,092	10,591	9,669	10,416	10,931	9,977	10,948	11,489	10,485
2012/13		10,590	11,262	9,898	10,923	11,617	10,210	11,469	12,198	10,724
2013/14		11,289	12,207	10,323	11,635	12,582	10,644	12,204	13,194	11,172
2014/15		11,874	13,030	10,542	12,230	13,420	10,867	12,812	14,056	11,400
2015/16		12,442	13,822	10,755	12,809	14,229	11,085	13,411	14,895	11,630
2016/17		12,910	14,572	11,015	13,291	15,002	11,353	13,918	15,705	11,913
2017/18		13,281	15,232	11,363	13,675	15,683	11,711	14,324	16,419	12,288
2018/19		13,609	16,351	11,514	14,012	16,818	11,866	14,676	17,582	12,450
2019/20		14,028	17,081	11,727	14,444	17,570	12,085	15,129	18,368	12,680
Average annual growth	2.1%	4.2%	6.2%	2.4%	4.2%	6.2%	2.4%	4.1%	6.1%	2.3%

Table 4-9—Queensland winter maximum demand projections (MW)

Winter	Actual	90% POE			50% POE			10% POE		
		Medium	High	Low	Medium	High	Low	Medium	High	Low
2005	7,354									
2006	7,628									
2007	7,924									
2008	8,312									
2009	7,774									
2010		8,444	8,669	8,268	8,612	8,843	8,433	8,729	8,963	8,548
2011		8,692	9,235	8,270	8,865	9,419	8,435	8,986	9,548	8,549
2012		9,094	9,893	8,414	9,274	10,090	8,582	9,401	10,229	8,697

Winter	Actual	90% POE			50% POE			10% POE		
		Medium	High	Low	Medium	High	Low	Medium	High	Low
2013		9,688	10,792	8,738	9,878	11,004	8,911	10,011	11,154	9,029
2014		10,349	11,824	9,029	10,549	12,053	9,205	10,687	12,212	9,326
2015		10,620	12,387	8,927	10,824	12,625	9,101	10,960	12,786	9,217
2016		11,347	13,507	9,212	11,561	13,762	9,389	11,705	13,937	9,509
2017		11,723	14,290	9,400	11,943	14,558	9,580	12,091	14,743	9,703
2018		12,010	15,018	9,558	12,236	15,300	9,741	12,389	15,495	9,864
2019		12,402	15,849	9,683	12,635	16,147	9,868	12,793	16,353	9,993
2020		12,774	16,674	9,803	13,015	16,988	9,991	13,177	17,204	10,117
Average annual growth	1.4%	4.2%	6.8%	1.7%	4.2%	6.7%	1.7%	4.2%	6.7%	1.7%

Figure 4-7 and Figure 4-8 compare the summer and winter medium growth 50% and 10% POE MD projections for the 2010 and 2009 ESOOs. The 10% POE projections are:

- 11 MW lower for the 2010/11 summer
- 784 MW higher for the 2018/19 summer
- 275 MW lower for the 2011 winter, and
- 807 MW higher for the 2019 winter.

The latest MD projections, although similar in the short-term, are approximately 1,000 MW higher by 2020 than last year's projections. This is due to expected increased demand in the Surat Basin area due to coal seam gas and coal mining developments, together with the establishment of support infrastructure and services.

Figure 4-7—Comparison of Queensland medium growth summer maximum demand projections (MW)

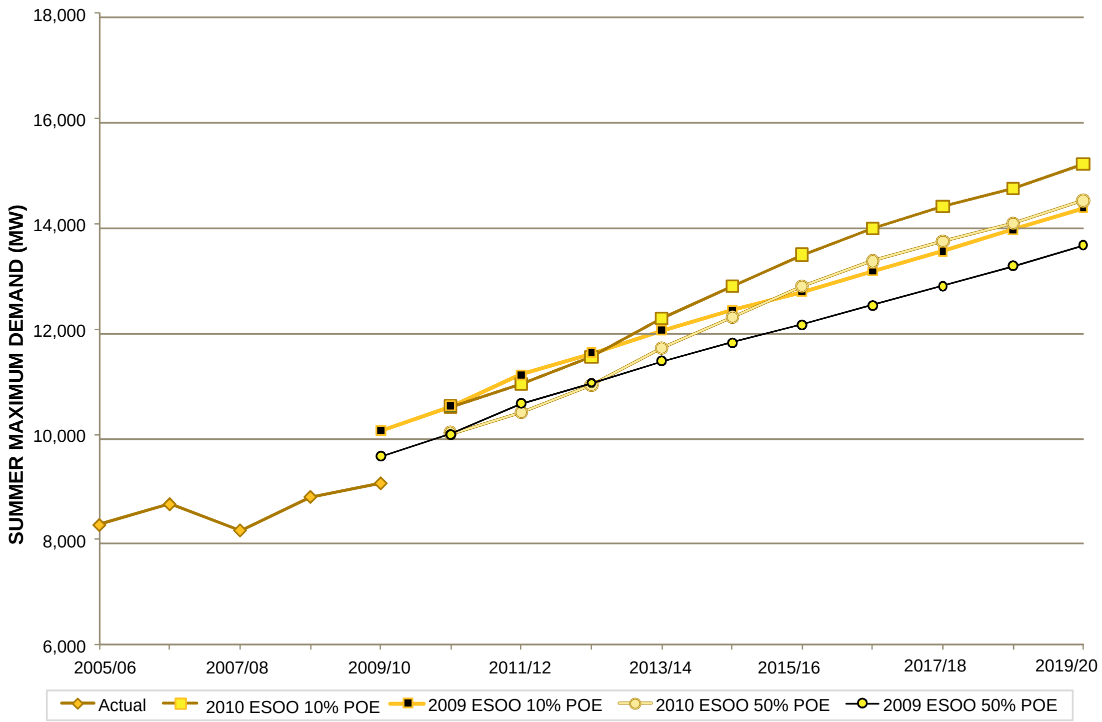
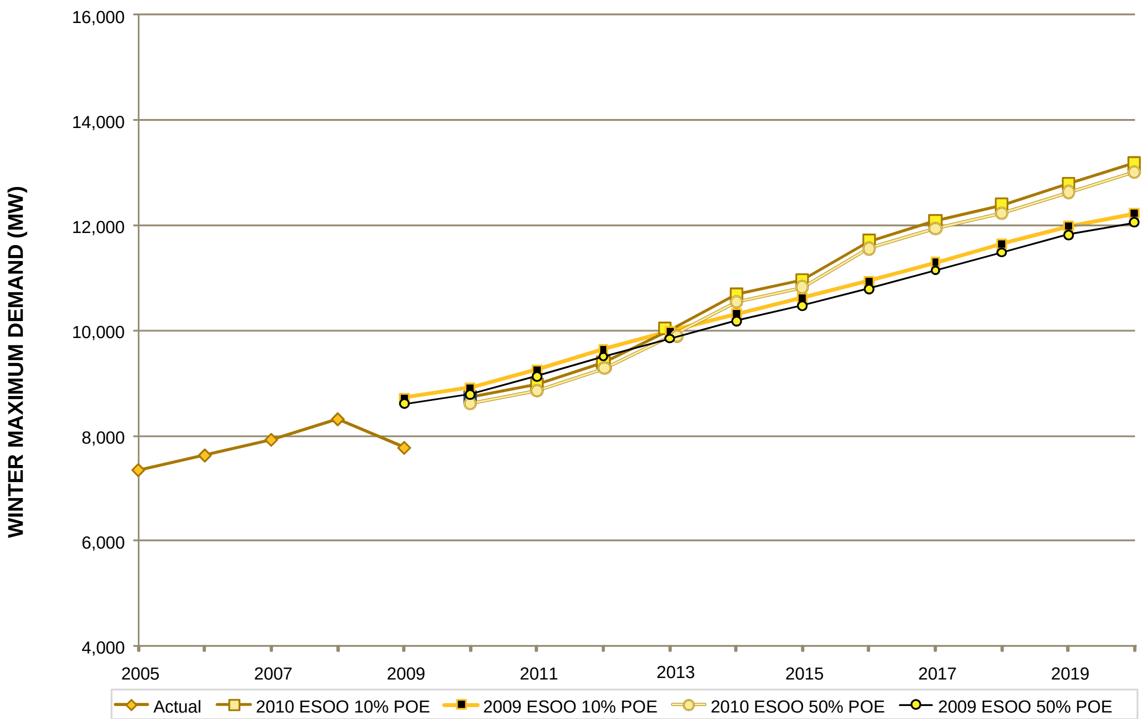


Figure 4-8—Comparison of Queensland medium growth winter maximum demand projections (MW)



4.5 New South Wales, including the Australian Capital Territory

TransGrid provided the energy and MD projections and supporting information for New South Wales. This information is consistent with the 2010 New South Wales Annual Planning Report.

4.5.1 Energy

Table 4-10 presents the recent actual energy and medium, high, and low economic growth scenario energy projections for New South Wales. Energy is projected to increase over the next 10 years at an annual average rate of:

- 1.8% under the medium growth scenario, and
- 2.0% and 1.5% under the high and low growth scenarios, respectively.

Table 4-10—New South Wales energy projections (GWh)

Financial year	Actual	Medium growth	High growth	Low growth
2004/05	71,727			
2005/06	74,041			
2006/07	74,790			
2007/08	74,992			
2008/09	75,857			
2009/10 (estimate)	75,421			
2010/11		77,720	77,810	77,481
2011/12		80,098	80,516	79,403
2012/13		81,187	81,723	80,374
2013/14		81,657	82,241	80,895
2014/15		83,241	84,033	82,518
2015/16		84,983	85,963	84,290
2016/17		86,389	87,497	85,577
2017/18		87,468	88,636	86,428
2018/19		88,705	89,962	87,279
2019/20		90,962	92,615	88,913
Average annual growth	1.0%	1.8%	2.0%	1.5%

Figure 4-9 compares the medium growth projections for the 2010 and 2009 ESOOs. The latest energy projection is approximately 2,000-3,000 GWh higher than last year's projection.

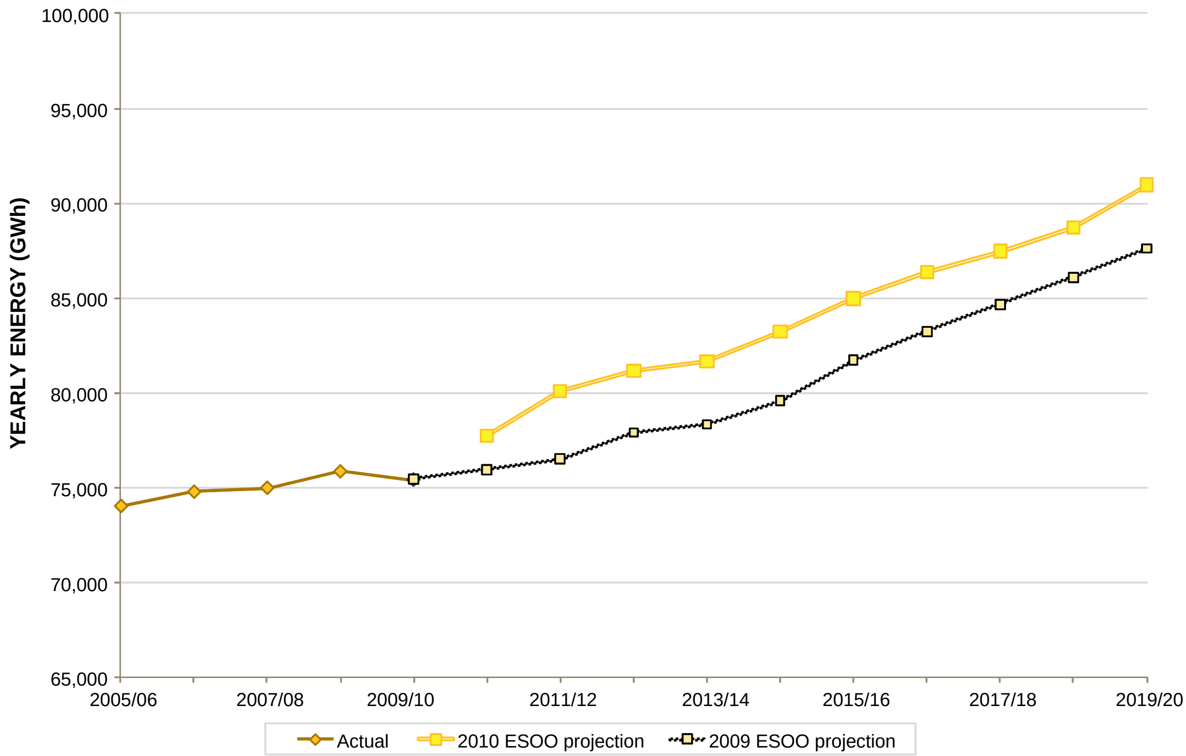
The difference between the projections is primarily due to the improved near term economic outlook, compared to last year's outlook. The New South Wales economy held up better than expected in 2009/10 and growth is expected to pick up and reach pre-Global Financial Crisis (GFC) levels in the coming years.

Additional changes to the New South Wales energy projections resulted from:

- the postponement of the proposed Carbon Pollution Reduction Scheme (CPRS), which led to revised energy price projections

- changes to post-modelling adjustments to better account for policy decisions likely to affect energy efficiency, such as the phasing out of greenhouse-intensive water heaters, the introduction of the New South Wales Energy Savings Scheme, and the phasing out of incandescent light bulbs
- allowances for new spot loads, including the desalination plant at Kurnell, and
- a lower base for the starting year of the projections, as the actual energy for 2008/09 was lower than previously estimated due to the global financial crisis downturn.

Figure 4-9—Comparison of New South Wales medium growth energy projections (GWh)



4.5.2 Maximum demand

Table 4-11 and Table 4-12 present actual and projected summer and winter MD projections for New South Wales.

The summer 10% POE MD is projected to increase over the next 10 years at an annual average rate of:

- 2.3% under the medium growth scenario, and
- 2.6% and 2.1% under the high and low growth scenarios, respectively.

The winter 10% POE MD is projected to increase over the next 10 years at an annual average rate of:

- 2.3% under the medium growth scenario, and
- 2.5% and 2.0% under the high and low growth scenarios, respectively.

Table 4-11—New South Wales summer maximum demand projections (MW)

Summer	Actual	90% POE			50% POE			10% POE		
		Medium	High	Low	Medium	High	Low	Medium	High	Low
2004/05	12,946									
2005/06	13,462									
2006/07	12,981									
2007/08	13,071									
2008/09	14,288									
2009/10 (estimate)	14,051									
2010/11		13,767	13,798	13,706	14,687	14,718	14,626	15,657	15,688	15,596
2011/12		14,209	14,259	14,130	15,169	15,219	15,090	16,169	16,229	16,090
2012/13		14,504	14,586	14,404	15,504	15,586	15,394	16,544	16,636	16,434
2013/14		14,807	14,919	14,678	15,847	15,969	15,718	16,927	17,049	16,788
2014/15		15,122	15,273	14,955	16,202	16,363	16,035	17,322	17,493	17,145
2015/16		15,434	15,628	15,234	16,554	16,758	16,344	17,714	17,928	17,484
2016/17		15,751	15,997	15,499	16,911	17,167	16,649	18,101	18,377	17,829
2017/18		16,073	16,369	15,761	17,273	17,579	16,951	18,493	18,829	18,151
2018/19		16,394	16,751	16,022	17,624	18,001	17,242	18,884	19,291	18,472
2019/20		16,716	17,129	16,258	17,976	18,419	17,518	19,266	19,749	18,778
Average annual growth	1.7%	2.2%	2.4%	1.9%	2.3%	2.5%	2.0%	2.3%	2.6%	2.1%

Table 4-12—New South Wales winter maximum demand projections (MW)

Winter	Actual	90% POE			50% POE			10% POE		
		Medium	High	Low	Medium	High	Low	Medium	High	Low
2005	13,186									
2006	13,166									
2007	13,985									
2008	14,368									
2009	13,091									
2010		13,877	13,897	13,846	14,236	14,257	14,205	14,655	14,676	14,625
2011		14,278	14,329	14,208	14,648	14,699	14,567	15,077	15,128	14,996
2012		14,629	14,700	14,501	14,999	15,079	14,870	15,448	15,528	15,309
2013		14,914	15,015	14,775	15,293	15,395	15,154	15,742	15,854	15,603
2014		15,187	15,318	15,077	15,586	15,707	15,467	16,045	16,177	15,926
2015		15,501	15,652	15,404	15,900	16,051	15,803	16,369	16,530	16,272
2016		16,002	16,176	15,893	16,411	16,595	16,302	16,900	17,094	16,791
2017		16,388	16,603	16,226	16,807	17,033	16,646	17,316	17,552	17,135
2018		16,749	17,005	16,488	17,178	17,444	16,907	17,697	17,973	17,416
2019		17,030	17,336	16,649	17,469	17,775	17,078	17,988	18,314	17,587
2020		17,421	17,793	16,944	17,870	18,252	17,374	18,409	18,811	17,893
Average annual growth	-0.2%	2.3%	2.5%	2.0%	2.3%	2.5%	2.0%	2.3%	2.5%	2.0%

The 2010 MD projections are marginally higher than last year.

Figure 4-10 and Figure 4-11 compare the summer and winter medium growth 50% and 10% POE MD projections for the 2010 and 2009 ESOOs. The projections are:

- 9 MW lower for the 2010/11 summer
- 192 MW higher for the 2018/19 summer
- 41 MW higher for the 2011 winter, and
- 356 MW higher for the 2019 winter.

The differences between the 2009 and 2010 MD projections are due to higher average demand for electricity, consistent with the less severe than expected New South Wales economic slowdown and subsequent return to the trend rate of gross state product (GSP) growth. There have also been some changes in assumptions with respect to post-modelling adjustments and large spot loads.

Figure 4-10—Comparison of New South Wales medium growth summer maximum demand projections (MW)

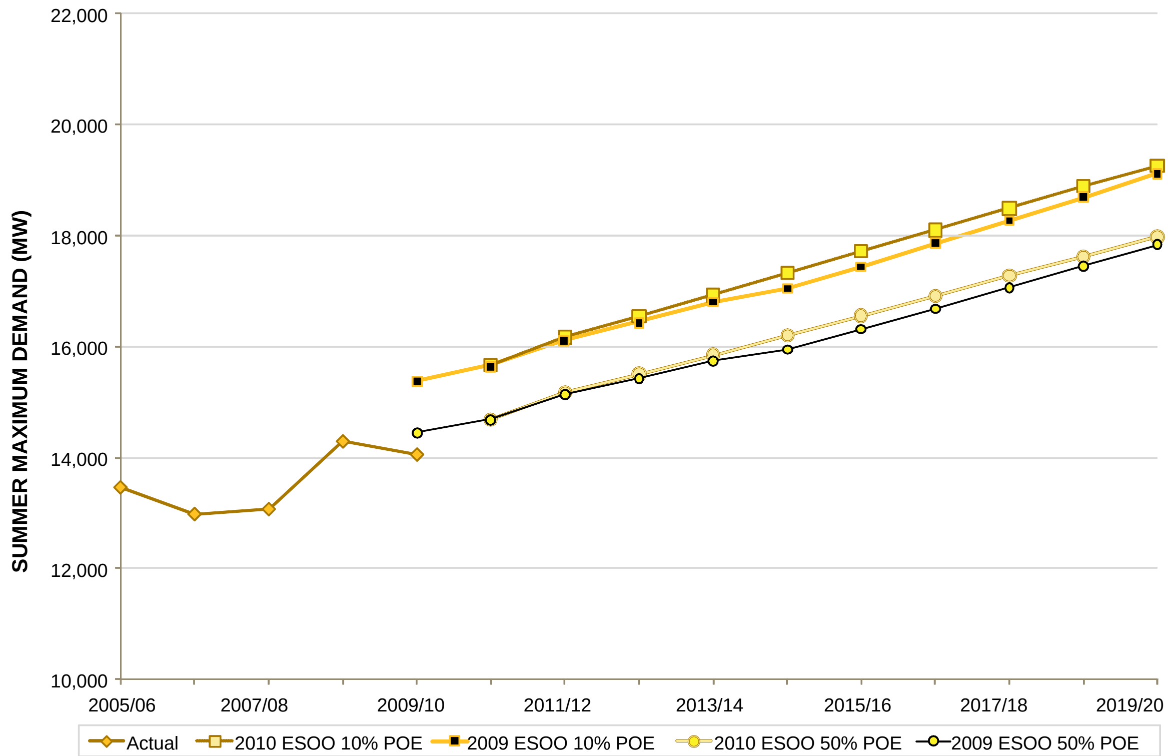
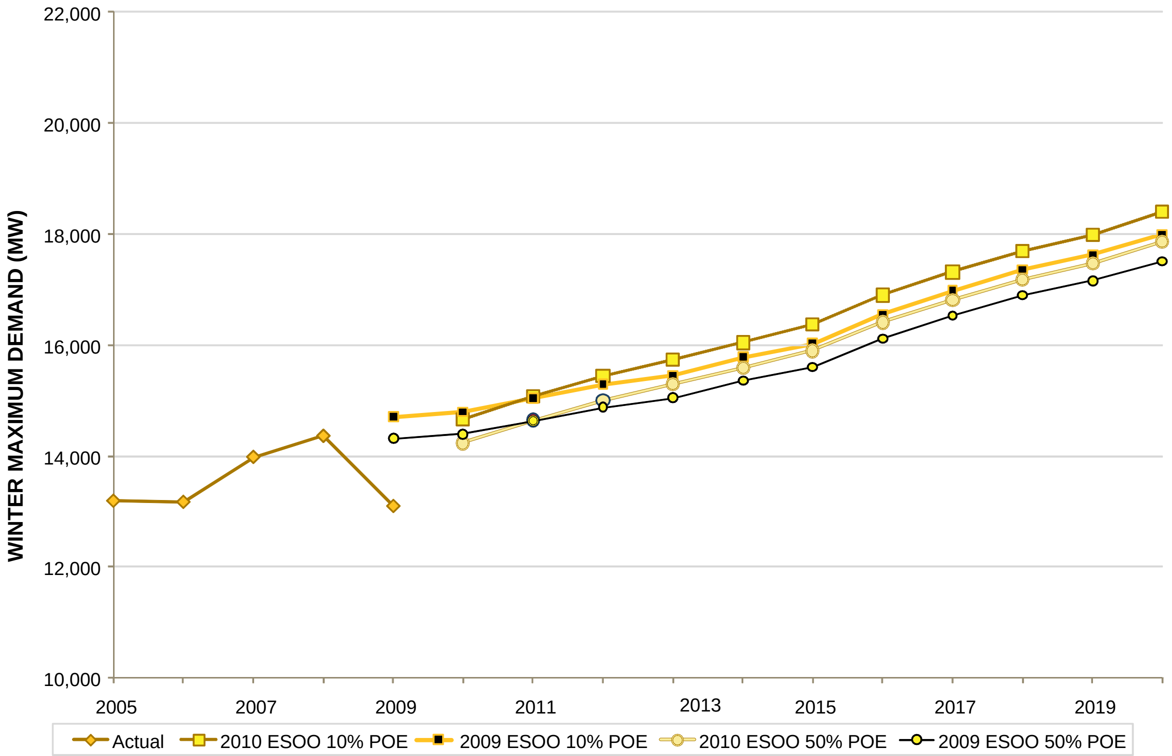


Figure 4-11—Comparison of New South Wales medium growth winter maximum demand projections (MW)



4.6 Victoria

AEMO provided the energy and MD projections and supporting information for Victoria. This information is consistent with the 2010 Victorian Annual Planning Report.

4.6.1 Energy

Table 4-13 presents the recent actual energy and medium, high, and low economic growth scenario energy projections for Victoria. Energy is projected to increase over the next 10 years at an annual average rate of:

- 1.0% under the medium growth scenario, and
- 1.5% and 0.4% under the high and low growth scenarios, respectively.

Table 4-13—Victorian energy projections (GWh)

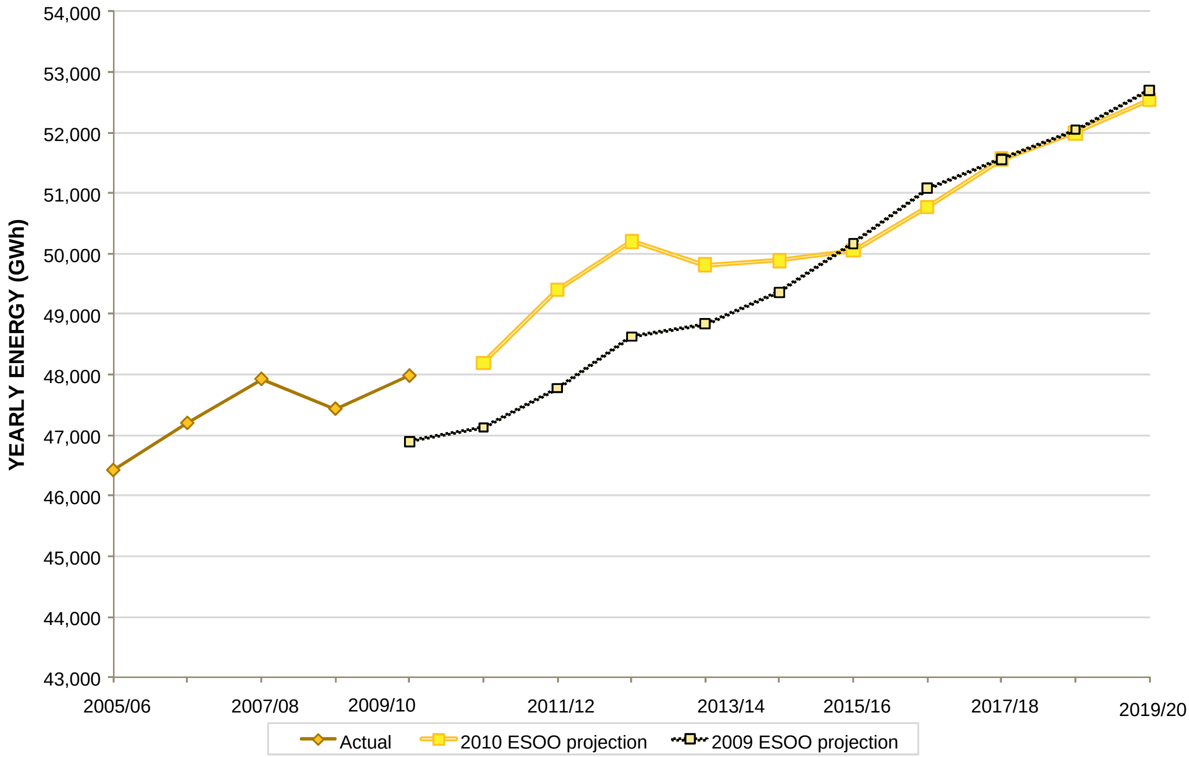
Financial year	Actual	Medium growth	High growth	Low growth
2004/05	45,597			
2005/06	46,426			
2006/07	47,201			
2007/08	47,926			
2008/09	47,436			
2009/10 (estimate)	47,980			

Financial year	Actual	Medium growth	High growth	Low growth
2010/11		48,186	48,599	47,976
2011/12		49,399	50,427	47,909
2012/13		50,202	51,206	48,162
2013/14		49,817	51,230	48,079
2014/15		49,886	51,612	47,937
2015/16		50,045	52,650	48,278
2016/17		50,772	53,388	48,551
2017/18		51,566	54,102	48,794
2018/19		51,993	54,812	49,041
2019/20		52,544	55,783	49,924
Average annual growth	1.0%	1.0%	1.5%	0.4%

Figure 4-12 compares the medium growth projections for the 2010 and 2009 ESOOs. The latest energy projection is approximately 1,000 GWh higher than last year's projection until 2013/14, then returns to previously expected levels.

The difference between the projections is primarily due to the improved economic outlook in the near term, compared to last year's outlook. The downturn in energy consumption that was assumed to occur as a result of last year's financial crisis has not being as significant as forecast. This results in the updated near-term energy forecasts being higher than those presented in the 2009 ESOO.

Figure 4-12—Comparison of Victorian medium growth energy projections (GWh)



4.6.2 Maximum demand

Figure 4-14 and Figure 4-15 present actual and projected summer and winter MD projections for Victoria.

The summer 10% POE MD is projected to increase over the next 10 years at an annual average rate of:

- 2.0% under the medium growth scenario, and
- 2.4% and 1.7% under the high and low growth scenarios, respectively.

The winter 10% POE MD is projected to increase over the next 10 years at an annual average rate of:

- 1.3% under the medium growth scenario, and
- 1.7% and 1.0% under the high and low growth scenarios, respectively.

Table 4-14—Victorian summer maximum demand projections (MW)

Summer	Actual	90% POE			50% POE			10% POE		
		Medium	High	Low	Medium	High	Low	Medium	High	Low
2004/05	8,566									
2005/06	8,788									
2006/07	9,134									
2007/08	9,878									
2008/09	10,505									
2009/10 (estimate)	10,118									
2010/11		9,481	9,604	9,372	10,063	10,188	9,952	10,783	10,911	10,670
2011/12		9,747	9,878	9,552	10,367	10,503	10,168	11,103	11,244	10,903
2012/13		9,941	10,134	9,724	10,567	10,764	10,343	11,372	11,598	11,120
2013/14		10,083	10,318	9,831	10,754	10,999	10,495	11,461	11,716	11,193
2014/15		10,211	10,471	9,923	10,934	11,208	10,638	11,673	11,963	11,365
2015/16		10,426	10,740	10,102	11,129	11,457	10,793	11,990	12,339	11,639
2016/17		10,589	10,915	10,198	11,302	11,643	10,896	12,174	12,542	11,751
2017/18		10,815	11,170	10,394	11,566	11,943	11,127	12,421	12,826	11,962
2018/19		10,965	11,368	10,554	11,712	12,141	11,281	12,699	13,163	12,242
2019/20		11,173	11,635	10,739	11,959	12,452	11,503	12,930	13,461	12,445
Average annual growth	3.4%	1.8%	2.2%	1.5%	1.9%	2.3%	1.6%	2.0%	2.4%	1.7%

Table 4-15—Victorian winter maximum demand projections (MW)

Winter	Actual	90% POE			50% POE			10% POE		
		Medium	High	Low	Medium	High	Low	Medium	High	Low
2005	7,810									
2006	7,899									
2007	8,435									
2008	8,093									
2009	8,178									

Winter	Actual	90% POE			50% POE			10% POE		
		Medium	High	Low	Medium	High	Low	Medium	High	Low
2010		8,057	8,176	8,014	8,176	8,295	8,132	8,347	8,450	8,285
2011		8,137	8,260	8,008	8,262	8,386	8,133	8,429	8,538	8,283
2012		8,353	8,543	8,154	8,477	8,670	8,278	8,650	8,829	8,433
2013		8,422	8,706	8,243	8,550	8,839	8,370	8,733	9,011	8,535
2014		8,503	8,817	8,294	8,629	8,948	8,418	8,816	9,125	8,585
2015		8,572	8,899	8,331	8,702	9,035	8,459	8,886	9,207	8,622
2016		8,695	9,073	8,421	8,828	9,212	8,551	9,010	9,383	8,711
2017		8,863	9,230	8,524	8,991	9,365	8,650	9,175	9,538	8,812
2018		8,977	9,373	8,614	9,107	9,509	8,740	9,289	9,681	8,900
2019		9,081	9,513	8,733	9,220	9,659	8,868	9,431	9,860	9,053
2020		9,202	9,685	8,837	9,343	9,834	8,974	9,532	10,013	9,137
Average annual growth	1.2%	1.3%	1.7%	1.0%	1.3%	1.7%	1.0%	1.3%	1.7%	1.0%

Figure 4-13 and Figure 4-14 compare the summer and winter medium growth 50% and 10% POE MD projections for the 2010 and 2009 ESOOs. The projections are:

- 81 MW higher for the 2010/11 summer
- 133 MW higher for the 2018/19 summer
- 144 MW higher for the 2011 winter, and
- 160 MW higher for the 2019 winter.

The latest MD projections are marginally higher than last year's projections.

The differences between the 2009 and 2010 MD projections are due to higher average demand for electricity, consistent with the less severe than expected economic slowdown in Victoria and subsequent return to the trend rate of GSP growth. Delaying the proposed Carbon Pollution Reduction Scheme (CPRS), which led to revised energy price projections, has resulted in the forecast slowing of demand growth to shift from 2011/12 to 2013/14.

Figure 4-13—Comparison of Victorian medium growth summer maximum demand projections (MW)

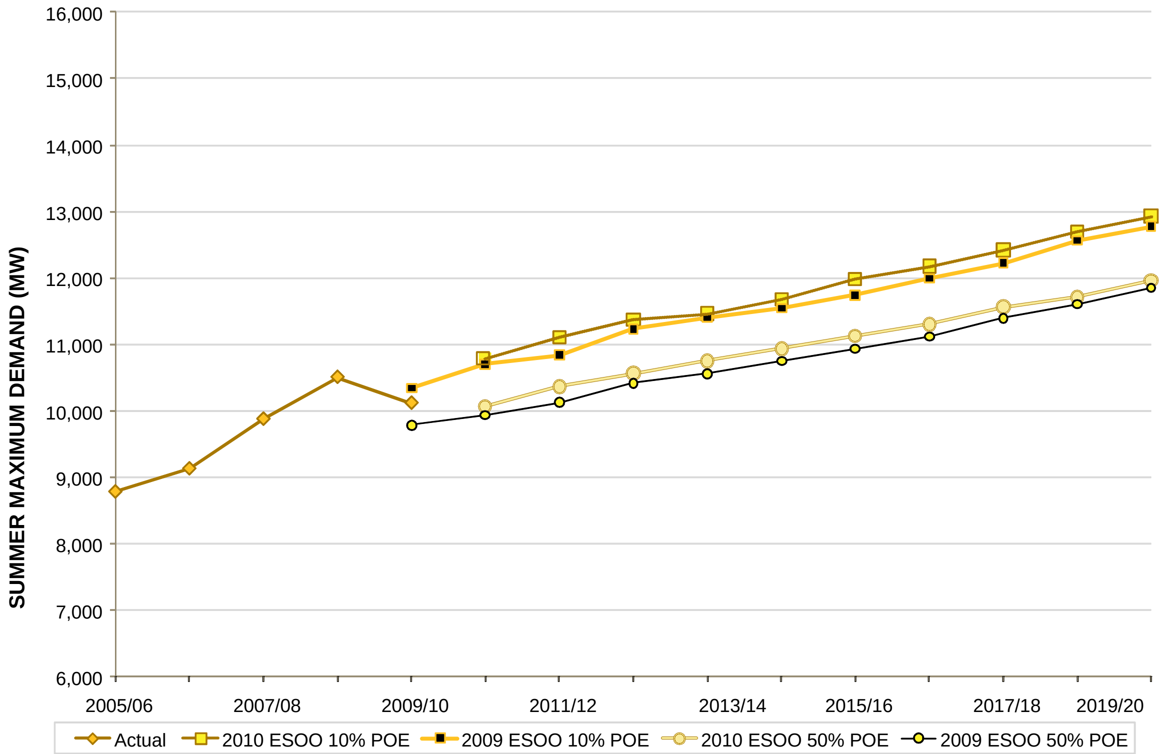
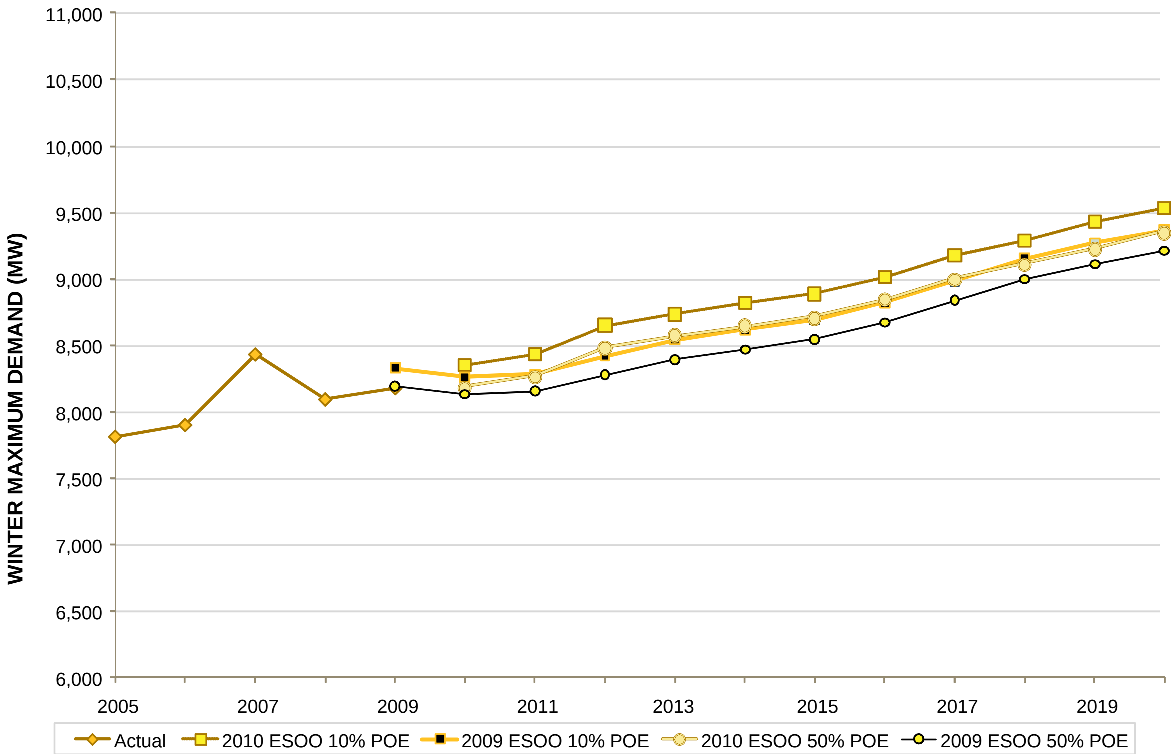


Figure 4-14—Comparison of Victorian medium growth winter maximum demand projections (MW)



4.7 South Australia

AEMO provided the energy and MD projections and supporting information for South Australia. This information is consistent with the 2010 South Australian Supply-Demand Outlook.

4.7.1 Energy

Table 4-16 presents the recent actual energy and medium, high, and low economic growth energy projections for South Australia. Energy is projected to increase over the next 10 years at an annual average rate of:

- 0.9% under the medium growth scenario, and
- 3.6% and 0.3% under the high and low growth scenarios, respectively.

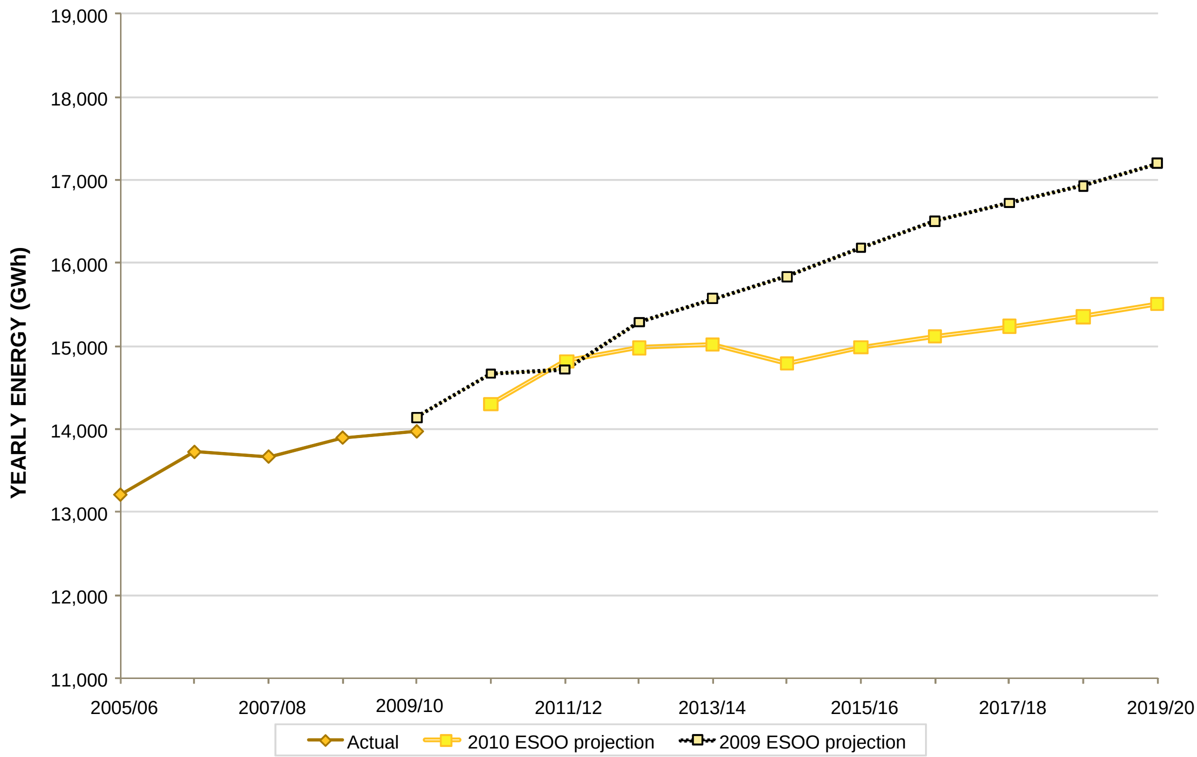
Table 4-16—South Australian energy projections (GWh)

Financial year	Actual	Medium growth	High growth	Low growth
2004/05	12,696			
2005/06	13,207			
2006/07	13,727			
2007/08	13,671			
2008/09	13,901			
2009/10 (estimate)	13,977			
2010/11		14,307	14,358	14,317
2011/12		14,824	15,022	14,390
2012/13		14,982	16,077	14,471
2013/14		15,020	16,669	14,458
2014/15		14,788	17,465	14,560
2015/16		14,989	18,104	14,611
2016/17		15,119	18,677	14,620
2017/18		15,239	18,962	14,617
2018/19		15,356	19,573	14,662
2019/20		15,512	19,816	14,768
Average annual growth	1.9%	0.9%	3.6%	0.3%

Figure 4-15 compares the medium growth projections for the 2010 and 2009 ESOOs. The latest energy projection is approximately 1,500 GWh lower than last year's projection.

The difference between the projections is primarily due to an improved economic outlook in the near term and a reduced economic outlook after that, when compared with last year's outlook. Energy policy impacts are also more pronounced in the later years, after 2013, when compared to the 2009 ESOO, resulting in significantly lower energy growth.

Figure 4-15—Comparison of South Australian medium growth energy projections (GWh)



4.7.2 Maximum demand

Table 4-17 and Table 4-18 present actual and projected summer and winter MD projections for South Australia.

The summer 10% POE MD is projected to increase over the next 10 years at an annual average rate of:

- 1.4% under the medium growth scenario, and
- 3.0% and 0.9% under the high and low growth scenarios, respectively.

The winter 10% POE MD is projected to increase over the next 10 years at an annual average rate of:

- 1.4% under the medium growth scenario, and
- 3.2% and 0.9% under the high and low growth scenarios, respectively.

Table 4-17—South Australian summer maximum demand projections (MW)

Summer	Actual	90% POE			50% POE			10% POE		
		Medium	High	Low	Medium	High	Low	Medium	High	Low
2004/05	2,701									
2005/06	2,971									
2006/07	2,955									
2007/08	3,213									
2008/09	3,490									
2009/10 (estimate)	3,341									

Summer	Actual	90% POE			50% POE			10% POE		
		Medium	High	Low	Medium	High	Low	Medium	High	Low
2010/11		3,000	3,000	2,980	3,220	3,230	3,210	3,530	3,520	3,520
2011/12		3,080	3,110	3,030	3,330	3,340	3,250	3,630	3,630	3,560
2012/13		3,130	3,260	3,050	3,370	3,510	3,290	3,670	3,810	3,600
2013/14		3,170	3,370	3,070	3,400	3,620	3,300	3,720	3,910	3,630
2014/15		3,160	3,490	3,100	3,430	3,760	3,350	3,730	4,080	3,670
2015/16		3,220	3,610	3,140	3,470	3,880	3,380	3,780	4,200	3,690
2016/17		3,270	3,740	3,160	3,510	3,990	3,400	3,860	4,320	3,700
2017/18		3,310	3,790	3,190	3,570	4,070	3,420	3,880	4,400	3,740
2018/19		3,370	3,910	3,220	3,620	4,180	3,460	3,940	4,520	3,780
2019/20		3,420	3,980	3,250	3,670	4,250	3,510	4,010	4,610	3,830
Average annual growth	4.3%	1.5%	3.2%	1.0%	1.5%	3.1%	1.0%	1.4%	3.0%	0.9%

Table 4-18—South Australian winter maximum demand projections (MW)

Winter	Actual	90% POE			50% POE			10% POE		
		Medium	High	Low	Medium	High	Low	Medium	High	Low
2005	2,299									
2006	2,399									
2007	2,473									
2008	2,568									
2009	2,460									
2010		2,430	2,430	2,420	2,540	2,530	2,540	2,660	2,660	2,670
2011		2,470	2,480	2,460	2,580	2,580	2,580	2,710	2,730	2,700
2012		2,550	2,570	2,490	2,660	2,680	2,600	2,790	2,820	2,730
2013		2,580	2,720	2,510	2,690	2,830	2,630	2,820	2,970	2,750
2014		2,590	2,810	2,530	2,710	2,920	2,650	2,850	3,060	2,770
2015		2,580	2,910	2,550	2,710	3,040	2,680	2,850	3,200	2,810
2016		2,630	3,030	2,580	2,750	3,150	2,700	2,890	3,300	2,830
2017		2,670	3,130	2,600	2,790	3,250	2,720	2,940	3,400	2,850
2018		2,700	3,190	2,620	2,830	3,320	2,740	2,980	3,470	2,880
2019		2,750	3,290	2,650	2,870	3,420	2,760	3,010	3,570	2,900
2020		2,780	3,340	2,690	2,910	3,470	2,790	3,060	3,630	2,920
Average annual growth	1.7%	1.4%	3.2%	1.1%	1.4%	3.2%	0.9%	1.4%	3.2%	0.9%

Figure 4-16 and Figure 4-17 compare the summer and winter medium growth 50% and 10% POE MD projections for the 2010 and 2009 ESOOs. The 10% POE projections are:

- 10 MW lower for the 2010/11 summer
- 250 MW lower for the 2018/19 summer
- 80 MW lower for the 2011 winter, and
- 300 MW lower for the 2019 winter.

The latest MD projections, although similar in the short-term, are 250 MW to 300 MW lower by 2020 than last year's projections. The differences between the 2009 and 2010 MD projections are due to both a reduction in the forecast economic outlook and the delay of the proposed Carbon Pollution Reduction Scheme (CPRS), which led to revised energy price projections, and the forecast slowing of demand growth shifting from 2011/12 to 2013/14.

Figure 4-16—Comparison of South Australian medium growth summer maximum demand projections (MW)

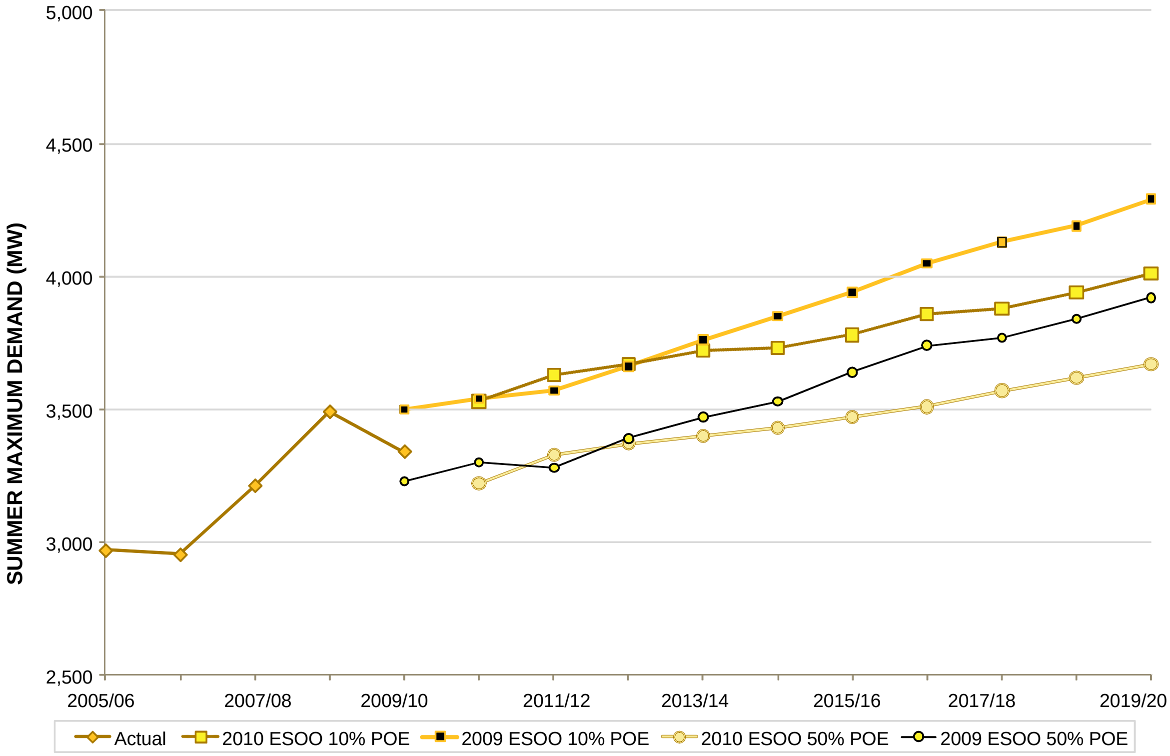
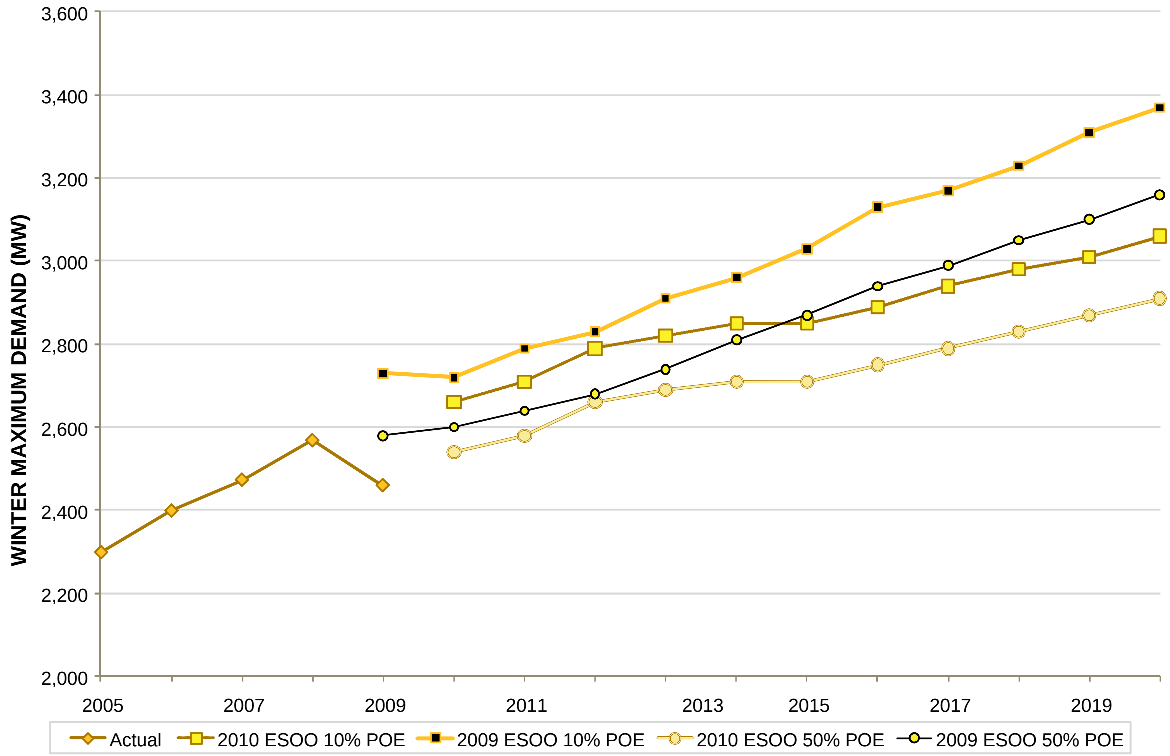


Figure 4-17—Comparison of South Australian medium growth winter maximum demand projections (MW)



4.8 Tasmania

Transend Networks provided the energy and MD projections and supporting information for Tasmania. This information is consistent with the 2010 Tasmanian Annual Planning Report.

4.8.1 Energy

Table 4-19 presents the recent actual energy and medium, high, and low economic growth energy projections for Tasmania. Energy is projected to increase over the next 10 years at an annual average rate of:

- 0.6% under the medium growth scenario, and
- 2.1% and -0.7% under the high and low growth scenarios, respectively.

Table 4-19—Tasmanian energy projections (GWh)

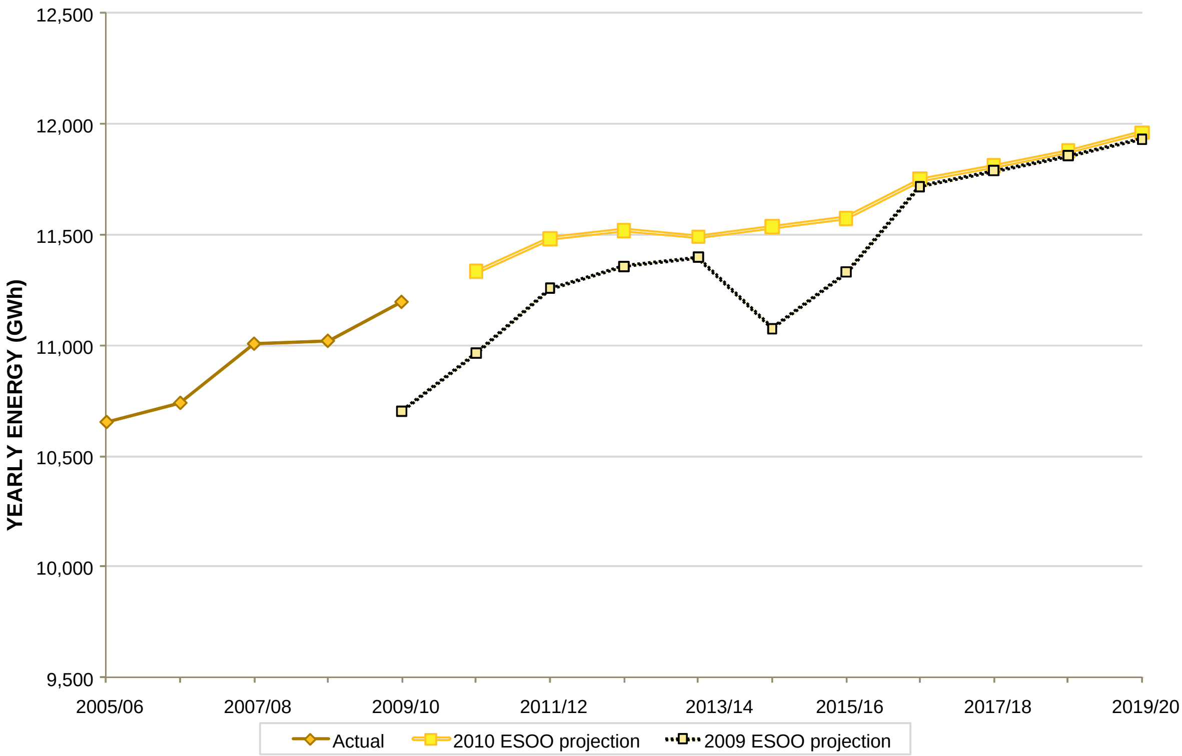
Financial year	Actual	Medium growth	High growth	Low growth
2004/05	10,675			
2005/06	10,652			
2006/07	10,739			
2007/08	11,008			
2008/09	11,021			
2009/10 (estimate)	11,199			
2010/11		11,334	11,839	10,769

Financial year	Actual	Medium growth	High growth	Low growth
2011/12		11,482	12,202	10,849
2012/13		11,518	12,337	10,805
2013/14		11,491	12,449	10,765
2014/15		11,536	12,579	10,759
2015/16		11,573	12,795	10,475
2016/17		11,750	13,155	10,147
2017/18		11,811	13,286	10,152
2018/19		11,878	14,215	10,136
2019/20		11,960	14,311	10,118
Average annual growth	1.0%	0.6%	2.1%	-0.7%

Figure 4-18 compares the medium growth projections for the 2010 and 2009 ESOOs. The latest medium growth energy projection starts approximately 370 GWh higher than last year's projection, but is almost identical from 2016/17 onwards.

The difference between the projections is primarily due to the improved near-term economic outlook, compared to last year's outlook. The Tasmanian economy held up much better than expected in 2009/10 and growth is expected to pick up and reach pre-crisis levels in the coming years.

Figure 4-18—Comparison of Tasmanian medium growth energy projections (GWh)



4.8.2 Maximum demand

Table 4-20 and Table 4-21 present actual and projected summer and winter MD projections for Tasmania.

The winter 10% POE MD is projected to increase over the next 10 years at an annual average rate of:

- 1.0% under the medium growth scenario, and
- 2.1% and 0.0% under the high and low growth scenarios, respectively.

The summer 10% POE MD is projected to increase over the next 10 years at an annual average rate of:

- 1.0% under the medium growth scenario, and
- 2.4% and -0.1% under the high and low growth scenarios, respectively.

Table 4-20—Tasmanian winter maximum demand projections (MW)

Winter	Actual	90% POE			50% POE			10% POE		
		Medium	High	Low	Medium	High	Low	Medium	High	Low
2005	1,803									
2006	1,716									
2007	1,803									
2008	1,861									
2009	1,753									
2010		1,889	1,948	1,828	1,908	1,969	1,847	1,932	1,994	1,870
2011		1,924	2,015	1,858	1,944	2,037	1,878	1,968	2,062	1,901
2012		1,931	2,026	1,843	1,951	2,048	1,863	1,976	2,074	1,886
2013		1,939	2,054	1,843	1,959	2,077	1,863	1,983	2,103	1,886
2014		1,956	2,085	1,848	1,977	2,108	1,868	2,001	2,135	1,891
2015		1,968	2,129	1,832	1,988	2,152	1,851	2,013	2,180	1,875
2016		1,997	2,195	1,806	2,017	2,219	1,826	2,042	2,247	1,850
2017		2,013	2,223	1,814	2,034	2,247	1,834	2,059	2,276	1,858
2018		2,033	2,347	1,821	2,055	2,372	1,841	2,080	2,401	1,865
2019		2,059	2,368	1,820	2,080	2,393	1,840	2,106	2,423	1,864
2020		2,086	2,396	1,830	2,108	2,422	1,850	2,135	2,452	1,874
Average annual growth	-0.7%	1.0%	2.1%	0.0%	1.0%	2.1%	0.0%	1.0%	2.1%	0.0%

Table 4-21—Tasmanian summer maximum demand projections (MW)

Summer	Actual	90% POE			50% POE			10% POE		
		Medium	High	Low	Medium	High	Low	Medium	High	Low
2004/05	1,367									
2005/06	1,315									
2006/07	1,393									
2007/08	1,425									
2008/09	1,475									
2009/10 (est.)	1,390									
2010/11		1,483	1,520	1,421	1,498	1,536	1,436	1,523	1,562	1,461
2011/12		1,509	1,572	1,439	1,525	1,589	1,455	1,550	1,616	1,479
2012/13		1,520	1,595	1,440	1,536	1,612	1,455	1,561	1,639	1,480
2013/14		1,522	1,614	1,442	1,538	1,632	1,457	1,563	1,660	1,481
2014/15		1,535	1,637	1,448	1,550	1,654	1,463	1,576	1,683	1,488
2015/16		1,546	1,669	1,418	1,562	1,687	1,434	1,588	1,716	1,458
2016/17		1,575	1,721	1,384	1,591	1,740	1,400	1,617	1,769	1,424
2017/18		1,590	1,744	1,392	1,606	1,763	1,408	1,633	1,793	1,432
2018/19		1,606	1,860	1,397	1,622	1,879	1,412	1,649	1,910	1,437
2019/20		1,624	1,878	1,401	1,641	1,898	1,417	1,668	1,929	1,442
Average annual growth	0.3%	1.0%	2.4%	-0.2%	1.0%	2.4%	-0.2%	1.0%	2.4%	-0.1%

Figure 4-19 and Figure 4-20 compares the summer and winter medium growth 50% and 10% POE MD projections for the 2010 and 2009 ESOOs. The 10% POE projections are:

- 53 MW lower for the 2011 winter
- 99 MW lower for the 2019 winter
- 33 MW higher for the 2010/11 summer, and
- 15 MW lower for the 2018/19 summer.

The latest MD projections are marginally higher than last year's projections.

The differences between the 2009 and 2010 MD projections are due to higher average demand for electricity, consistent with the less severe than expected economic slowdown in Victoria and subsequent return to the trend rate of GSP growth.

Figure 4-19—Comparison of Tasmanian medium growth winter maximum demand projections (MD)

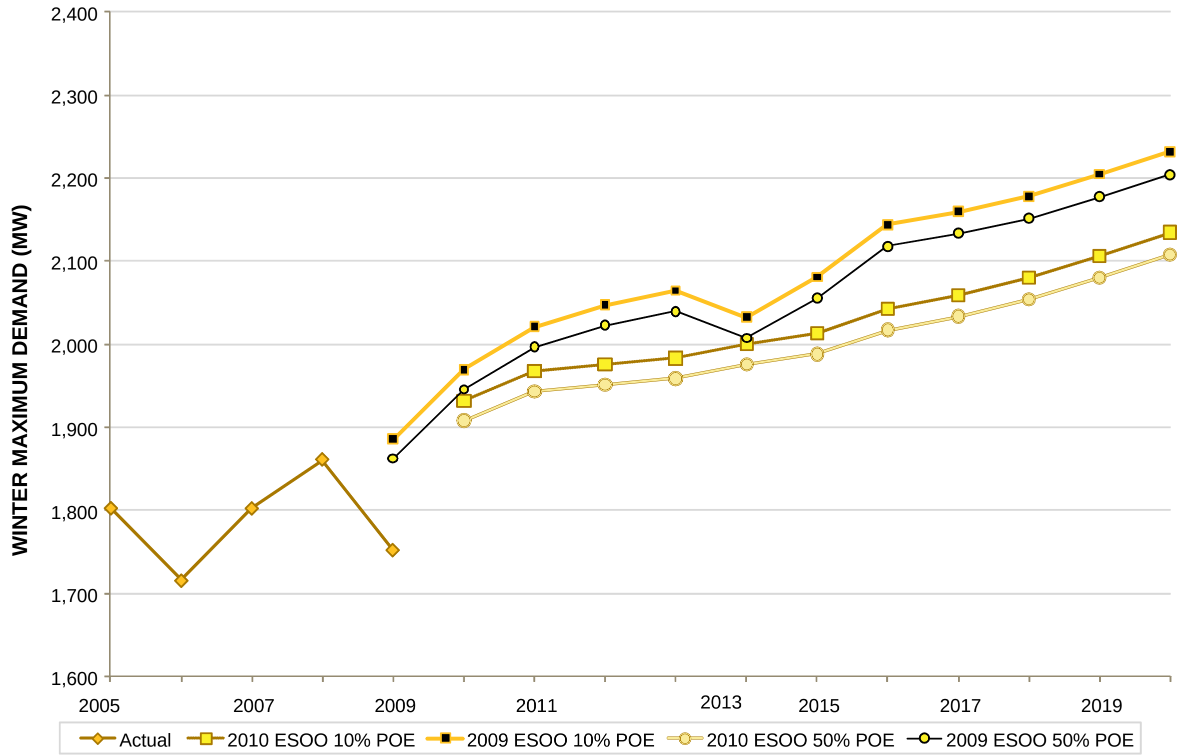
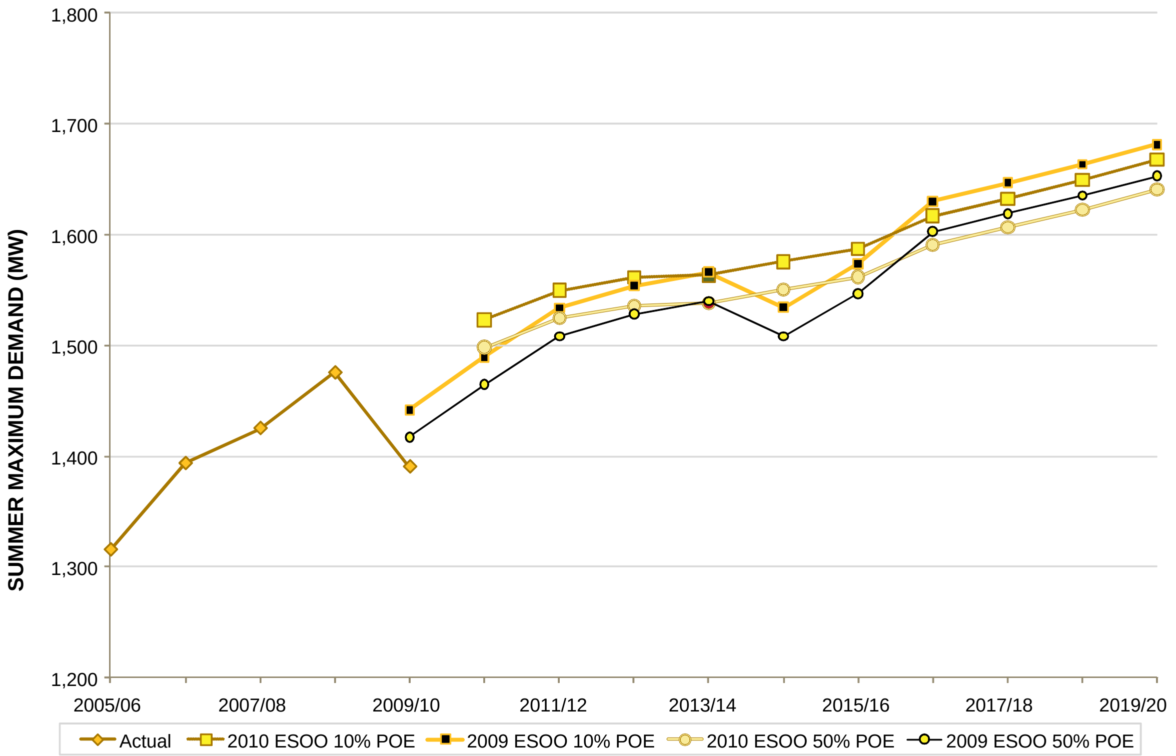


Figure 4-20—Comparison of Tasmanian medium growth summer maximum demand projections (MD)



4.9 Non-scheduled generation projections

This section presents projections of the contribution from non-scheduled generation to energy and MD for the NEM as a whole and for each region.

The non-scheduled generation projections are subtracted from the projections of regional energy and MD to create the scheduled and semi-scheduled generation projections used in the supply-demand outlook.

4.9.1 NEM-wide energy and maximum demand supplied by non-scheduled generating units

Table 4-22 presents actual and medium, high, and low economic growth, NEM-wide projections of non-scheduled generation capacity and energy.

Table 4-23 presents NEM-wide projections of the contribution to summer MD from non-scheduled generation.

Energy supplied by non-scheduled generating units is projected to increase over the next 10 years at an annual average rate of 2.6%-3.7%, compared with historical growth of 19.2%. This is mainly due to the predominance of existing wind farms in the non-scheduled classification. The slower future growth reflects the fact that the majority of future new wind generating units will be classified as semi-scheduled, rather than non-scheduled. This also explains the relatively slow projected growth in the contribution to MD from non-scheduled generating units.

Table 4-22—NEM-wide projections of non-scheduled generation capacity and energy

Financial year	Actual capacity MW	Actual energy GWh	Medium capacity MW	Medium energy GWh	High capacity MW	High energy GWh	Low capacity MW	Low energy GWh
2004/05	1,885	2,560						
2005/06	2,039	3,096						
2006/07	2,102	3,359						
2007/08	2,372	4,222						
2008/09	3,007	5,065						
2009/10 (estimate)	3,063	6,170						
2010/11			3,217	6,712	3,219	6,714	3,215	6,710
2011/12			3,425	7,098	3,430	7,110	3,421	7,089
2012/13			3,457	7,575	3,470	7,587	3,447	7,566
2013/14			3,468	7,715	3,484	7,727	3,455	7,706
2014/15			3,515	7,775	3,541	7,801	3,490	7,754
2015/16			3,515	7,870	3,541	7,896	3,490	7,849
2016/17			3,520	7,889	3,548	7,915	3,494	7,868
2017/18			3,522	7,981	3,550	8,008	3,495	7,959
2018/19			3,522	8,040	3,550	8,848	3,495	8,018
2019/20			3,630	8,502	3,691	9,313	3,576	8,477
Average annual growth	12.3%	19.2%	1.4%	2.7%	1.5%	3.7%	1.2%	2.6%

Table 4-23—NEM-wide projections of the non-scheduled generation contribution to summer maximum demand (MW)

Summer	Actual	Medium growth	High growth	Low growth	Contribution factor
2004/05	327				0.17
2005/06	354				0.17
2006/07	441				0.21
2007/08	534				0.23
2008/09	479				0.16
2009/10	710				0.23
2010/11		724	725	723	0.23
2011/12		768	772	765	0.23
2012/13		841	844	838	0.25
2013/14		875	878	872	0.25
2014/15		894	904	886	0.26
2015/16		896	906	888	0.26
2016/17		897	906	889	0.26
2017/18		901	911	892	0.26
2018/19		902	1,063	894	0.26
2019/20		934	1,097	925	0.26
Average annual growth	16.7%	2.9%	4.7%	2.8%	1.5%

4.9.2 Queensland

Table 4-24 presents actual and medium, high, and low economic growth projections of non-scheduled generation capacity and energy for Queensland.

Table 4-25 presents projections of the contribution to the summer MD from Queensland non-scheduled generation.

Energy supplied by non-scheduled generating units is not projected to increase over the next 10 years, compared with historical growth of 51.9%. Much of the historical growth can be attributed to cogeneration at sugar mills. No significant additional non-scheduled generating capacity is expected to be added in Queensland in the next 10 years.

Table 4-24—Queensland projections of non-scheduled generation capacity and energy

Financial year	Actual capacity MW	Actual energy GWh	Medium capacity MW	Medium energy GWh	High capacity MW	High energy GWh	Low capacity MW	Low energy GWh
2004/05	336	195						
2005/06	393	144						
2006/07	445	413						
2007/08	496	1,085						
2008/09	618	1,196						
2009/10 (estimate)	628	1,572						
2010/11			628	1,452	629	1,452	627	1,452
2011/12			628	1,452	630	1,452	627	1,452
2012/13			628	1,452	630	1,452	627	1,452

Financial year	Actual capacity MW	Actual energy GWh	Medium capacity MW	Medium energy GWh	High capacity MW	High energy GWh	Low capacity MW	Low energy GWh
2013/14			628	1,452	630	1,452	627	1,452
2014/15			639	1,452	644	1,452	635	1,452
2015/16			639	1,452	644	1,452	635	1,452
2016/17			639	1,452	644	1,452	635	1,452
2017/18			639	1,452	644	1,452	635	1,452
2018/19			639	1,452	644	1,452	635	1,452
2019/20			639	1,452	644	1,452	635	1,452
Average annual growth	13.3%	51.9%	0.2%	0.0%	0.3%	0.0%	0.1%	0.0%

Table 4-25—Queensland projections of the non-scheduled generation contribution to summer maximum demand (MW)

Summer	Actual	Medium growth	High growth	Low growth	Contribution factor
2004/05	32				0.09
2005/06	4				0.01
2006/07	68				0.15
2007/08	159				0.32
2008/09	105				0.17
2009/10	180				0.29
2010/11		180	180	180	0.29
2011/12		180	180	180	0.29
2012/13		180	180	180	0.29
2013/14		180	180	180	0.29
2014/15		180	180	180	0.28
2015/16		180	180	180	0.28
2016/17		180	180	180	0.28
2017/18		180	180	180	0.28
2018/19		180	180	180	0.28
2019/20		180	180	180	0.28
Average annual growth	41.5%	0.0%	0.0%	0.0%	-0.2%

4.9.3 New South Wales

Table 4-26 presents actual and medium, high, and low economic growth projections of non-scheduled generation capacity and energy for New South Wales.

Table 4-27 presents projections of the contribution to the summer MD from New South Wales non-scheduled generation.

Energy supplied by non-scheduled generating units is projected to increase over the next 10 years at an annual average rate of 0.9%-1.2%, compared with historical growth of 14%. Much of the historical growth can be attributed to the installation of cogeneration at existing sugar mills. The projections do not anticipate any further growth from this source. Also contributing to relatively low projected growth is the fact that all future wind farm projects are expected to be classified as semi-scheduled, rather than non-scheduled, as are most existing wind farms. This is also true of the regional MD contribution from non-scheduled generating units.

Table 4-26—New South Wales projections of non-scheduled generation capacity and energy

Financial year	Actual capacity	Actual energy	Medium capacity	Medium energy	High capacity	High energy	Low capacity	Low energy
	MW	GWh	MW	GWh	MW	GWh	MW	GWh
2004/05	534	845						
2005/06	534	951						
2006/07	537	904						
2007/08	751	913						
2008/09	797	1,192						
2009/10 (estimate)	801	1,627						
2010/11			850	1,702	851	1,704	850	1,700
2011/12			892	1,808	896	1,820	889	1,799
2012/13			892	1,808	896	1,820	889	1,799
2013/14			892	1,808	896	1,820	889	1,799
2014/15			921	1,855	932	1,881	912	1,834
2015/16			921	1,855	932	1,881	912	1,834
2016/17			921	1,855	932	1,881	912	1,834
2017/18			923	1,860	935	1,887	914	1,838
2018/19			923	1,860	935	1,887	914	1,838
2019/20			927	1,868	940	1,898	917	1,843
Average annual growth	8.4%	14.0%	1.0%	1.0%	1.1%	1.2%	0.9%	0.9%

Table 4-27—New South Wales projections of the non-scheduled generation contribution to summer maximum demand (MW)

Summer	Actual	Medium growth	High growth	Low growth	Contribution factor
2004/05	106				0.20
2005/06	170				0.32
2006/07	105				0.20
2007/08	131				0.17
2008/09	187				0.23
2009/10	285				0.36
2010/11		460	460	459	0.54
2011/12		502	506	498	0.56
2012/13		502	506	498	0.56
2013/14		502	506	498	0.56
2014/15		523	534	515	0.57
2015/16		523	534	515	0.57
2016/17		523	534	515	0.57
2017/18		525	536	516	0.57
2018/19		525	536	516	0.57
2019/20		529	542	519	0.57
Average annual growth	21.9%	1.6%	1.8%	1.4%	0.6%

4.9.4 Victoria

Table 4-28 presents actual and medium, high, and low economic growth projections of non-scheduled generation capacity and energy for Victoria.

Table 4-29 presents projections of the contribution to the summer MD from Victorian non-scheduled generation.

Energy supplied by non-scheduled generating units is projected to increase over the next 10 years at an annual average rate of 10.1%, compared with historical growth of 15.5%. Much of the historical growth can be attributed to new wind farm capacity. The slower future growth mainly reflects the transfer of expected growth in wind farm capacity from a non-scheduled to semi-scheduled classification. This is also true of the regional MD contribution from non-scheduled generating units.

Table 4-28—Victorian projections of non-scheduled generation capacity and energy

Financial year	Actual capacity	Actual energy	Medium capacity	Medium energy	High capacity	High energy	Low capacity	Low energy
	MW	GWh	MW	GWh	MW	GWh	MW	GWh
2004/05	324	357						
2005/06	349	355						
2006/07	352	417						
2007/08	353	399						
2008/09	809	620						
2009/10 (estimate)	828	735						
2010/11			836	750	837	750	836	750
2011/12			836	1,030	837	1,030	836	1,030
2012/13			836	1,420	837	1,420	836	1,420
2013/14			836	1,511	837	1,511	836	1,511
2014/15			843	1,524	844	1,524	840	1,524
2015/16			843	1,619	844	1,619	840	1,619
2016/17			849	1,637	850	1,637	844	1,637
2017/18			849	1,725	850	1,725	844	1,725
2018/19			849	1,784	850	1,784	844	1,784
2019/20			849	1,784	850	1,784	844	1,784
Average annual growth	20.6%	15.5%	0.2%	10.1%	0.2%	10.1%	0.1%	10.1%

Table 4-29—Victorian projections of the non-scheduled generation contribution to summer maximum demand (MW)

Summer	Actual	Medium growth	High growth	Low growth	Contribution factor
2004/05	54				0.17
2005/06	58				0.17
2006/07	72				0.20
2007/08	60				0.17
2008/09	57				0.07
2009/10	225				0.27
2010/11		51	51	51	0.06
2011/12		58	58	58	0.07
2012/13		132	132	132	0.16
2013/14		165	165	165	0.20
2014/15		165	165	165	0.20
2015/16		168	168	168	0.20
2016/17		168	168	168	0.20
2017/18		170	170	170	0.20
2018/19		172	172	172	0.20
2019/20		172	172	172	0.20
Average annual growth	33.0%	14.4%	14.4%	14.4%	14.2%

4.9.5 South Australia

Table 4-30 presents actual and medium, high, and low economic growth projections of non-scheduled generation capacity and energy for South Australia.

Table 4-31 presents projections of the contribution to the summer MD from South Australian non-scheduled generation.

Energy supplied by non-scheduled generating units is projected to increase over the next 10 years at an annual average rate of 3.3%, compared with historical growth of 19.9%. Much of the historical growth in non-scheduled generation can be attributed to new wind farm capacity, despite the unique historical position of the South Australian region, which required larger wind farms to register their units as scheduled. The slower future growth mainly reflects the expectation that all future wind farm capacity will be registered with the market operator as semi-scheduled. This also explains the relatively low expected future growth of regional MD contributions from non-scheduled generating units.

Table 4-30—South Australian projections of non-scheduled generation capacity and energy

Financial year	Actual capacity	Actual energy	Medium capacity	Medium energy	High capacity	High energy	Low capacity	Low energy
	MW	GWh	MW	GWh	MW	GWh	MW	GWh
2004/05	447	472						
2005/06	517	887						
2006/07	517	1,010						
2007/08	517	1,078						
2008/09	554	1,172						

Financial year	Actual capacity MW	Actual energy GWh	Medium capacity MW	Medium energy GWh	High capacity MW	High energy GWh	Low capacity MW	Low energy GWh
2009/10 (estimate)	677	1,169						
2010/11			639	1,742	639	1,742	639	1,742
2011/12			639	1,742	639	1,742	639	1,742
2012/13			659	1,829	659	1,829	659	1,829
2013/14			670	1,878	673	1,878	668	1,878
2014/15			670	1,878	673	1,878	668	1,878
2015/16			670	1,878	673	1,878	668	1,878
2016/17			670	1,878	673	1,878	668	1,878
2017/18			670	1,878	673	1,878	668	1,878
2018/19			670	1,878	673	1,878	668	1,878
2019/20			774	2,332	808	2,332	746	2,332
Average annual growth	8.6%	19.9%	2.2%	3.3%	2.6%	3.3%	1.7%	3.3%

Table 4-31—South Australian projections of the non-scheduled generation contribution to summer maximum demand (MW)

Summer	Actual	Medium growth	High growth	Low growth	Contribution factor
2004/05	94				0.21
2005/06	92				0.18
2006/07	210				0.41
2007/08	143				0.28
2008/09	136				0.25
2009/10 (estimate)	62				0.09
2010/11		77	77	77	0.12
2011/12		77	77	77	0.12
2012/13		83	83	83	0.13
2013/14		86	86	86	0.13
2014/15		86	86	86	0.13
2015/16		86	86	86	0.13
2016/17		86	86	86	0.13
2017/18		86	86	86	0.13
2018/19		86	86	86	0.13
2019/20		117	117	117	0.15
Average annual growth	-8.0%	4.8%	4.8%	4.8%	2.6%

4.9.6 Tasmania

Table 4-32 presents actual and medium, high, and low economic growth projections of non-scheduled generation capacity and energy for Tasmania.

Table 4-33 presents projections of the contribution to the summer MD from Tasmanian non-scheduled generation.

Energy supplied by non-scheduled generating units is projected to increase over the next 10 years at an annual average rate between 0.0%-6.3%, compared with historical growth of 9.0%. Historically, growth was mostly due to increases in small hydro capacity. Future growth excludes new wind farm capacity, which is expected to be classified as semi-scheduled rather than non-scheduled. This also explains the lack of growth of the regional MD contributions from non-scheduled generating units.

Table 4-32—Tasmanian projections of non-scheduled generation capacity and energy

Financial year	Actual capacity	Actual energy	Medium capacity	Medium energy	High capacity	High energy	Low capacity	Low energy
	MW	GWh	MW	GWh	MW	GWh	MW	GWh
2004/05	245	692						
2005/06	247	759						
2006/07	250	616						
2007/08	255	748						
2008/09	264	885						
2009/10 (estimate)	264	1,066						
2010/11			264	1,066	264	1,066	264	1,066
2011/12			429	1,066	429	1,066	429	1,066
2012/13			441	1,066	448	1,066	435	1,066
2013/14			441	1,066	448	1,066	435	1,066
2014/15			441	1,066	448	1,066	435	1,066
2015/16			441	1,066	448	1,066	435	1,066
2016/17			441	1,066	448	1,066	435	1,066
2017/18			441	1,066	448	1,066	435	1,066
2018/19			441	1,066	614	1,847	435	1,066
2019/20			441	1,066	614	1,847	435	1,066
Average annual growth	1.5%	9.0%	5.9%	0.0%	9.8%	6.3%	5.7%	0.0%

Table 4-33—Tasmanian projections of the non-scheduled generation contribution to winter maximum demand (MW)

Winter	Actual	Medium growth	High growth	Low growth	Contribution factor
2005	132				0.54
2006	96				0.39
2007	108				0.43
2008	199				0.78
2009	83				0.32
2010	77				0.18
2011		77	77	77	0.29
2012		77	77	77	0.18
2013		77	77	77	0.17
2014		77	77	77	0.17

Winter	Actual	Medium growth	High growth	Low growth	Contribution factor
2015		77	77	77	0.17
2016		77	77	77	0.17
2017		77	77	77	0.17
2018		77	77	77	0.17
2019		77	243	77	0.17
2020		77	243	77	0.17
Average annual growth	-10.2%	0.0%	13.6%	0.0%	-5.6%

4.10 Demand-side participation results

Table 4-34 shows the estimated committed and non-committed historical demand-side participation (DSP) results from the 2010 DSP survey. See Section 4.11.11 for information about the DSP survey process in 2010.

Table 4-34—Estimated historical DSP (MW)

Region	2009 ESOO		2010 ESOO	
	Committed	Non-Committed	Committed	Non-Committed
Queensland	66	340	32	145
New South Wales	129	79	31	140
Victoria and South Australia	0	140	68	303
Tasmania	0	0	0	0

Table 4-35 shows the results of the 2010 survey regarding the amount of DSP available for the 2010/11 summer season.

Table 4-35—DSP available for the 2010/11 summer (MW)

	Very likely	Even chance	Extremely unlikely
Queensland	50	10	100
New South Wales	50	127	8
Victoria and South Australia	77	306	0
Tasmania	0	0	0

Table 4-36 shows future economic growth scenarios for DSP. The medium growth scenario is based on the 'very likely' amounts shown in Table 4-35, with percentage increases for small loads expected to grow in line with projected regional load growth. This does not include the DSP from large industrial loads included in Table 4-35, which are expected to remain static. The high growth scenario doubles the overall growth rates in the medium growth scenario, and the DSP amounts in the low growth scenario generally remain unchanged.

Table 4-36—Future scenarios for DSP (annual growth)

	Medium	High	Low
New South Wales	2.3%	4.6%	0.0%
Victoria and South Australia	1.5%	3.1%	0.0%
Queensland	1.0%	4.0%	0.0%
Tasmania	5 MW in 2011/12 then 7%	10 MW in 2011/12 then 5%	5 MW in 2014/15 then 0%

4.11 Process and methodology

This section provides a basic description of the process and methodology used to develop the energy and MD projections. Particular details of the approaches used for individual regions are available in the APR or supply-demand outlook for each region.

Energy, power and demand

Energy, defined as the capacity to do work, is measured over a length of time, and conventionally in multiples of watt-hours (Wh), such as megawatt-hours (MWh) or gigawatt-hours (GWh)[29]. The ESOO refers to energy in GWh, typically over the course of a year.

Power, defined as the rate of energy transfer, is measured at an instant in time, and conventionally in watts or some multiple thereof, such as kilowatts (kW) or megawatts (MW). For practical reasons, recordings of power within the electricity industry are averaged over short time intervals, typically a half-hour. The ESOO refers to power in MW measurement units.

Demand is generally understood in terms of the desire to purchase particular goods or services. However, in an electrical power system where demand and supply are continuously balanced, 'demand' is conventionally used to mean 'power'.

In the ESOO, unless otherwise obvious from the context, 'demand' refers to 'power'. It follows that 'maximum demand' is defined as the greatest single recorded power measurement out of a collection of similar measurements. MDs referred to in the ESOO are determined with reference to sequential measurements collected over an entire summer or winter season[30].

Probability of exceedence

The level of demand in each region is highly variable and at any instant depends on a variety of factors, including ambient temperature, habitual consumer behaviour and the coincidence of these factors across large regions. It is not usually possible to predict the precise impact of these causal factors very far ahead. As a result, the actual MDs in each year may vary above or below a more predictable growth trend. It is customary practice, therefore, to provide long-run MD projections on the basis of similar conditions in each year.

[29] Since one watt is equal to one Joule (J) applied for one second in S.I. units, one GWh equals $(1\times10^9)/(3600\times10^{15})$ or 1/0.0036 PJ.

[30] Seasonal MD is also frequently referred to elsewhere as 'peak demand'.

Renewable and non-renewable energy

The energy and MD projections in each category, whether scheduled and semi-scheduled or significant non-scheduled, include supply from both renewable and non-renewable sources.

All renewable energy sources in the NEM were originally small-scale and either distribution-system connected or located on the end-user's premises.

Growth in non-scheduled generation has mainly been synonymous with growth in renewable energy. This category received a significant incentive from the Mandatory Renewable Energy Target (MRET). Non-scheduled energy sources also include small-scale hydro-electric and biomass generation, as well as non-renewable sources such as coal-seam methane and conventional gas. Roof-top photovoltaic panels and other generation with individual capacities less than 1 MW are generally accounted for in the energy and MD projections as offsets to demand.

Since 2007, South Australian wind farms with a capacity greater than 30 MW were required to be registered as scheduled generators. In 2009 a National Electricity Rule (NER) change required that all new intermittent generators, including wind farms, with a capacity greater than 30 MW will be registered with AEMO as semi-scheduled. The semi-scheduled registration category requires intermittent generators to supply AEMO with availability and pricing information to enable management of their dispatch within the normal market formulation.

Future developments of renewable technologies that are not intermittent, such as geothermal power, will be subject to the registration rules applicable to conventionally-fuelled generation and will be registered as scheduled generation.

Application to the supply-demand balance

This chapter focuses on projections of underlying electricity use, based on patterns of economic behaviour and allowing for specific local investment plans. Therefore energy and demand from all sources of supply are considered.

The supply-demand outlook is, however, focused only on the generation capacity needed for dispatch in the National Electricity Market (NEM), along with committed levels of demand-side participation. Dispatchable generating units are only those registered with AEMO as either scheduled or semi-scheduled. Non-dispatchable generating units include those registered as non-scheduled (such as some wind farms commissioned prior to 2009) and those that are exempt from registration (such as roof-top solar photovoltaic panels). Therefore, the energy and MD projections require some adjustment before being used to generate the supply-demand outlook. Specifically, the supply-demand outlook uses:

- the regional 10% POE MD projections supplied by scheduled and semi-scheduled generating units, which are set out in Appendix A, and
- committed DSP projections (see Section 4.11.3).

4.11.1 Sources of the energy and maximum demand projections

Table 4-37 lists the energy and MD projection provider for each region. The projections for Victoria and South Australia were developed by AEMO with the assistance of the National Institute of Industry and Economic Research and Monash University, which was contracted to undertake various modelling aspects. The projections for New South Wales (including the Australian Capital Territory), Queensland, and Tasmania were provided by the respective JPBs and were either developed in-house or with the assistance of consultants contracted directly to the JPBs.

Table 4-37—Provision of the energy and maximum demand projections

Region	Responsibility for projections
Queensland	Powerlink Queensland
New South Wales and the Australian Capital Territory	TransGrid
Victoria and South Australia	AEMO
Tasmania	Transend Networks

4.11.2 Scenario construction

The projections were developed on the basis of medium, high, and low economic growth scenarios. These scenarios reflect different population, economic growth, price and other input assumptions provided by KPMG[31]. KPMG's economic scenarios were designed to be consistent with the energy market scenarios developed jointly by AEMO, the Department of Resources, Energy and Tourism (DRET) and an industry Stakeholder Reference Group (SRG)[32,33]. KPMG focussed on the economy-wide aspects of these scenarios (rather than the energy market specifically) to develop growth scenarios based on three broad factors:

- The strength of global economic growth and the resulting demand for Australian commodity exports and transfer of the benefits of technological innovation.
- The strength of Australian population growth.
- The assumed CO2-equivalent emissions targets and related carbon-price trajectories associated with an emissions trading scheme (although the original KPMG assumptions were modified slightly to reflect the deferral of this scheme, which was announced in April 2010).

[31] KPMG. Stage 2 Report – Economic Scenarios and Forecasts 2009/10 to 2029/30. Report to AEMO. April 2010.

[32] The SRG included industry experts with diverse experience and interests. The input of the group after several discussions was synthesised into a report by McLennan Magasanik Associates. This report was approved by the SRG and has been accepted by AEMO and DRET as a common strategic framework for long-term energy modelling.

[33] McLennan Magasanik Associates. Future Developments in the Stationary Energy Sector: Scenarios for the Stationary Energy Sector 2030. Report to AEMO/DRET. October 2009.

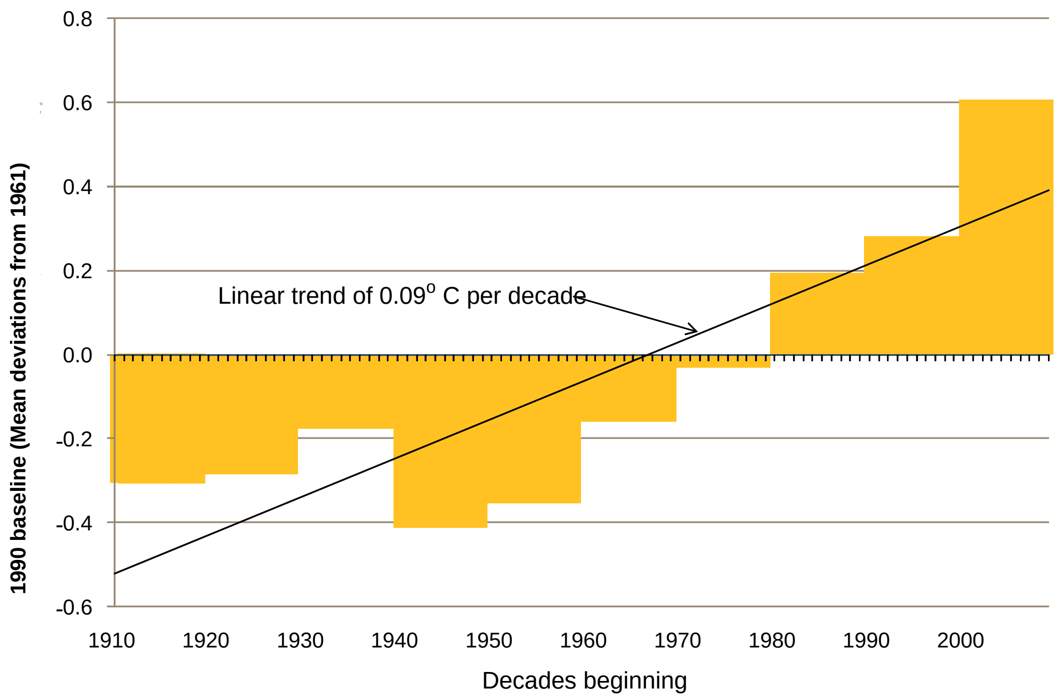
Treatment of long-term climate change

Rising temperature trends over at least the last 50 years are readily observable, as shown in Figure 4-21, and similar trends may continue in the future[34]. Accurately forecasting the energy and MD with conventional models becomes problematic for two reasons.

Firstly, the historical temperature trend means that any analysis based on the raw data will produce different results, depending on the time period used for analysis. Secondly, future projections that include a temperature assumption will vary according to the precise nature of that assumption. The projections presented in this chapter have addressed these two problems by:

- making allowances for historical temperature trends, and
- projecting long-run historical temperature trends into the future.

Figure 4-21—Decade-average temperature anomalies, Eastern Australia[35]



4.11.3 Demand-side participation

Demand-side participation (DSP) includes all short-term reductions in demand in response to temporary price increases (in the case of retailers and customers) or adverse network loading conditions (in the case of networks). An organised, aggregated response may also be possible. From the perspective of the transmission network, and consumers may effectively reduce demand by turning off electricity-using appliances or starting up on-site generators.

AEMO conducted a survey of stakeholders to ascertain potential DSP sites and to identify future DSP opportunities. The results of the survey form the basis of AEMO's regional estimates of

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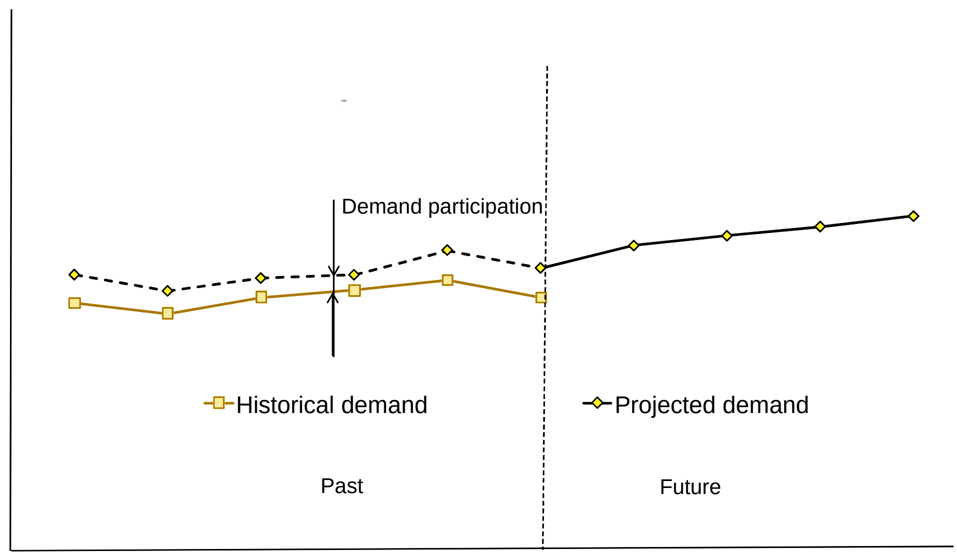
[34] The trend shown in Figure 4-21 is representative of Eastern Australia as a whole. Individual forecasters used temperature measures and trends associated with their respective regions.

[35] Source: Bureau of Meteorology, http://www.bom.gov.au/climate/change/.

historical and projected DSP. See Section 4.10 for the survey results for each region. See Section 4.11.11 for a description of the survey itself.

Figure 4-22 shows how DSP is treated by the demand projections. Historical DSP is added to recorded demand levels as a demand correction, returning it to levels that would have occurred without the economic decision for interruption by the retailer or customer. This corrected figure is used to determine projected ESOO MD trends. Since the projected MDs include DSP, this DSP is then included on the supply side in the supply-demand calculator.

Figure 4-22—Treatment of demand-side participation in the maximum demand projections



4.11.4 Overall AEMO load forecasting process

The projections for each region were prepared separately, with each contributing organisation applying its own approach, but using consistent definitions and input assumptions. Figure 4-23 shows these various approaches.

To support this process, AEMO convened a Load Forecasting Reference Group (LFRG) to coordinate the process and also engaged KPMG as an independent service provider.

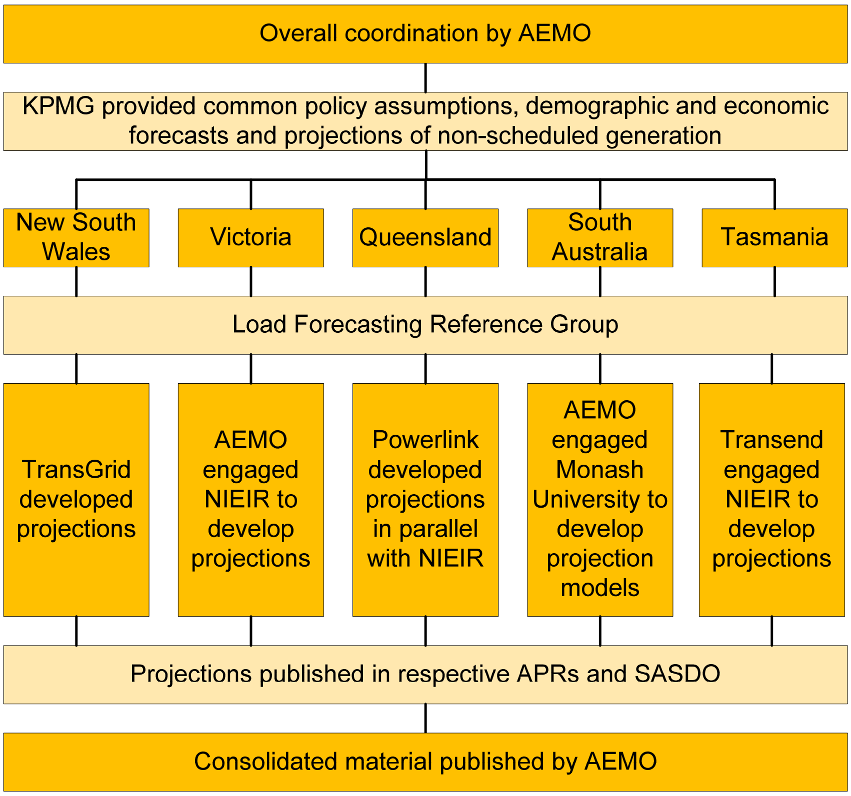
The LFRG is made up of the forecasters responsible for the projections in each region and is convened by AEMO. The main objectives of the LFRG are to achieve:

- consistent delivery outputs
- consistent definitions and input assumptions
- delivery of the projections in time for the ESOO, and
- continuous improvement of the load forecasting process.

The LFRG also acts as forum for the resolution of national load forecasting issues.

KPMG provided information to AEMO and each JPB about future energy policy developments, demographic and economic conditions, and growth in non-scheduled generation.

Figure 4-23—Load forecasting process



4.11.5 Factors influencing the demand for electricity

This section describes the series of broad factors that are considered significant when developing the long-term regional energy and MD projections.

Demographic and economic influences

Growth in electricity consumption in the longer term is primarily driven by demographic and economic considerations. Key long-term economic drivers include:

- population growth, both as a direct driver of residential demand and as an indirect driver of gross domestic product (GDP)
- economic activity, affecting both the demand for energy generally as well as electricity usage
- the electricity intensity of the economy[36], which reflects income level, industry structure, technology, energy prices, and climatic conditions
- electricity prices, particularly in relation to prices of substitute sources of energy (where available), which primarily reflect fuel sources and available technology for generation
- technological change (including more efficient appliances and the potential widespread use of plug-in electric vehicles), and
- domestic non-energy government policies, including government fiscal policy, which can influence the level of economic activity.

[36] The amount of electricity needed to produce one unit of GDP.

Energy sector policy influences

Possible energy sector policy developments that have a significant impact on demand growth include:

- carbon pricing under the proposed emissions trading scheme (or an alternative scheme)
- incentives for renewable energy under national renewable energy targets, and
- measures to improve the energy efficiency of appliances and buildings, as well as potentially increasing levels of DSP (including the Minimum Energy Performance Standards (MEPS)).

Weather-related, seasonal and large industrial influences

In the short term, considerable variation in demand for electricity occurs around the long-term growth trend. These variations are strongly related to changing weather conditions, but also display predictable seasonal, daily and hourly patterns.

Certain large industrial and mining projects can also be identified and accounted for directly in the energy and MD projections.

Maintaining energy and maximum demand projection consistency

To ensure that the policy and economic basis for the energy and MD projections is consistent, AEMO engaged KPMG to prepare a series of reports to derive input variable values for the regional projections of energy and MD and to specify projected regional capacity of significant non-scheduled generating units.

See Attachment 1 for more information about these reports and the policy and economic outlooks considered by AEMO and the JPBs when preparing the projections.

4.11.6 Summary of projection approaches

TransGrid

TransGrid developed its own energy and MD projections for New South Wales (including the Australian Capital Territory). The projections depend on the interaction of four separate TransGrid models, with inputs supplied from the KPMG reports, which are common to all regions.

The energy model is an estimated econometric model using monthly demographic, income, price and weather-dependent variables.

The weather correction model uses an estimated model of half-hourly historical demands with long-run trend, periodic, and weather-related dependent variables. Weather variables are de-trended to account for historical trends. The model is used to simulate a number of different outcomes, using block resampling, in order to determine a probability distribution of the summer and winter MDs for all historical years in the sample. The resulting probability distributions reflect a range of possible weather patterns and random model residuals. The 90th, 50th and 10th percentile of each distribution (90%, 50% and 10% POE) are selected as the historical series of MDs that are projected into the future using the MD models.

The MD models for summer and winter are estimated using historical MDs at the selected percentiles of the distribution. Each model relates MD to underlying energy growth using the projection from the energy model and changes in air-conditioning ownership. Future increasing temperature trends are incorporated in the projected growth trend via weather assumptions incorporated in the energy model. The three models for summer and three models for winter therefore implicitly project future MDs at their respective POE level.

TransGrid's models are generally used to predict energy and MD excluding major industrial loads, for which specific assumptions are made separately. These loads are then added back to the modelled projections.

The modelled New South Wales MD projections were reconciled with the aggregated connection point forecasts provided by distribution network service providers (DNSP) and major industrial customers in the region.

Details of TransGrid's load forecasting models are published in TransGrid's Annual Planning Report[37].

AEMO (Victoria)

AEMO engaged the National Institute of Economic and Industry Research (NIEIR) to prepare energy and MD projections for Victoria using inputs from the KPMG reports, which are common to all regions.

NIEIR's Victorian electrical energy forecasting model determines consumption for a number of individual industry categories. The projections are based on econometric models that link Victorian electricity sales by industry to real output growth by industry, electricity prices, and weather conditions. Residential sales are determined from another model that is based on average consumption per dwelling, with real income, electricity prices and weather as dependent variables. The Victorian energy projections are based on the sum of each industrial and residential sector, with appropriate allowances for losses.

Victorian summer and winter MD projections were produced using NIEIR's half-hourly PeakSim model. While non-weather dependent demand is also accounted for by NIEIR, the core of the PeakSim model is the strong relationship between demand and prevailing weather. Other contemporaneous influences and underlying drivers of demand are built on and around this relationship, including the regular time-varying component of demand, based on routine consumer behaviour, and the fundamental contribution to weather-varying demand of the stock of cooling equipment such as refrigerators and air conditioners.

The Victorian MD projections are developed by NIEIR using a number of simulated demand projections using different synthetic weather and random model residual inputs, as well as fixed projected energy growth trend and air-conditioning sales assumptions.

NIEIR's models are generally used to predict energy and demand excluding major industrial loads, for which specific assumptions are made separately. These loads are then added back to the modelled projections.

The modelled Victorian MD projections were reconciled with the aggregated connection point forecasts provided by the DSNPs and major industrial customers in the region.

Details of AEMO's load forecasting process for Victoria are published in the Victorian Annual Planning Report[38].

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[37] See http://www.transgrid.com.au/network/np/Pages/default.aspx.

[38] See http://www.aemo.com.au/planning/planning.html.

Powerlink Queensland

Powerlink Queensland developed energy and MD projections for Queensland by aggregating the forecasts produced by DNSPs and major industrial customers in that region. Powerlink also engaged NIEIR to develop modelled projections for Queensland with reference to the common KPMG reports as inputs. Powerlink then reconciled the aggregated DNSP projection with the modelled NIEIR projection.

Queensland DNSPs produce ‘most likely’ energy and summer and winter MD forecasts for each connection supply point in Powerlink's transmission network. Powerlink aggregated these individual connection supply point forecasts into forecasts for the total Queensland region using network loss and diversity factors, where necessary, observed from historical trends.

NIEIR provided an independent assessment of energy and demand forecasts for Queensland and for broad areas within Queensland. These forecasts were consistent with KPMG forecasts of Queensland gross state product (GSP), population, dwelling stock and levels of embedded generation. NIEIR also accounted for expected major new industrial and mining developments and the expected impact of carbon pricing. Unlike the distributor forecasts, the NIEIR MD projections are provided in the form of 90%, 50% and 10% POE projections, based on temperature sensitivities throughout Queensland.

The reconciliation process matches the distributor ‘bottom up’ forecast with NIEIR's ‘top down’ approach. This involves discussing any material differences with the distributors and bringing them into line with the NIEIR projection by appealing to the historical record or recent material changes to the economic outlook or other input assumptions.

Details of Powerlink’s load forecasting process are published in the Queensland Annual Planning Report[39].

AEMO South Australia

AEMO prepared energy and MD projections for South Australia using models developed by Monash University, and economic assumptions provided by the common KPMG reports.

There are a number of key features of the forecasting approach used by AEMO for South Australia.

A semi-parametric additive model is used to estimate the relationship between half hourly South Australian electricity demand and its driver variables, which include temperatures measured at two sites in Adelaide, calendar, and other time-of-year effects, demographic variables, and economic variables. The model is described in detail in Hyndman (2007)[40].

The model has an annual component, which uses demographic, economic, and climate variables, and a half-hourly component, which uses calendar and time-of-year variables together with a range of short-term temperature measures. Separate half-hourly models are estimated for each half hour of the day.

The models are used in conjunction with forecasts of the economic driver variables and simulated half-hourly temperatures to forecast the probability distribution of summer and winter MD in future

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[39] See http://www.powerlink.com.au/asp/index.asp?sid=5056&page=Network/development&cid=5259&gid=327.

[40] Hyndman, R.J. Extended Models for Long-Term Peak Half-hourly Electricity Demand for South Australia. Available at http://www.esipc.sa.gov.au/site/page.cfm?u=287. 22 May 2007.

years. Forecasts for 90%, 50% and 10% POE levels are then identified from these distributions. Forecasts of the annual energy requirement are calculated as the integral of a half-hourly demand trace for a particular year.

The variable selection process used to establish the models was based on out-of-sample forecasting performance. Variables considered for possible use included population, household size, number of households, inflation and interest rates, South Australian GSP, household disposable income, an index of the stock of air conditioning capacity, and average retail electricity prices. The best forecasting model was found to include per capita demand and GSP, average retail price lagged by one year, and summer cooling-degree days.

The temperature simulation process allows for climate change, with adjustments based on CSIRO modelling of future increases in South Australian temperature. The shifts in temperature until 2030 are predicted by CSIRO to be 1.5°C, 0.9°C and 0.3°C at the 90th, 50th and 10th percentiles, respectively.

The modelling process also allows for a random component of half-hourly demand, with model residuals re-sampled as part of the demand simulation process. Prior to re-sampling, model residuals are adjusted for bias found to be present in the unadjusted residuals, with the aim being to accurately capture the upper tail of the peak demand distribution.

Major industrial loads are treated separately within this modelling framework, with forecasts of the peak and average level of demand based on project-specific advice provided by South Australian DNSPs. This information is used to create probability distributions of major industrial demands in future years, with random samples drawn from these distributions and incorporated into the simulated demand traces for the state as a whole.

Details of AEMO's load forecasting process for South Australia are published in the South Australian Supply-Demand Outlook[41].

Transend Networks

Transend networks engaged NIEIR to develop energy and MD projections for Tasmania, consistent with the inputs described in the common KPMG reports.

NIEIR's Tasmanian electrical energy forecasting model determines consumption for a number of individual industry categories. The projections are based on econometric models that link Tasmanian electricity sales by industry to real output growth by industry, electricity prices, and weather conditions. Residential sales are determined from another model that is based on average consumption per dwelling, with real income, electricity prices and weather as dependent variables. The Tasmanian energy projections are based on the sum of each industrial and residential sector, with appropriate allowances for losses.

Forecasts of summer and winter MDs for Tasmania were developed using econometric relationships. These relationships relate the ratio of MD to energy and average temperature at the time of MD. The Tasmanian summer and winter MD, energy, and weather condition relationship estimates excluded the impact of the top four major industrial customers, which are assumed to be weather insensitive.

A detailed analysis of temperature data for Tasmania for the last 50 years was used to determine the probabilities of alternative winter and summer temperatures. In the NIEIR models, daily

[41] See http://www.aemo.com.au/planning/planning.html.

electricity MD in summer and winter depends on an average temperature calculated using the ambient minimum temperature:

- during the current day, and
- on the previous day.

The average temperature is defined as the weighted average of the overnight minimum and the previous daily maximum, using weightings of 0.8 and 0.2, respectively. Tasmanian MDs typically occur around 9:00 a.m.

All percentile calculations are based only on average temperature, since this is found to be the most important influence on demand variability. Other weather variables, such as humidity, rainfall and wind, were not considered in the POE calculations for Tasmania. The probabilities were calculated excluding weekends and summer holidays but including a warming trend.

NIEIR's models are generally used to predict energy and demand excluding major industrial loads, for which specific assumptions are made separately. These loads are then added back to the modelled projections.

The modelled Tasmanian MD projections were reconciled with the aggregated connection point forecasts provided by DNSPs and major industrial customers in the region.

Details of Transend's load forecasting process are published in the Tasmanian Annual Planning Report[42].

4.11.7 Own price and income elasticities of demand for electricity

The own price elasticity of electricity demand is defined as the proportional change in electricity consumed in response to a unit change in the price. As with most goods and services, the own price elasticity of electricity is negative, because an increase in price results in a decrease in consumption.

The income elasticity of electricity demand is defined as the proportional change in electricity consumed in response to a unit change in the income of consumers. For example, higher income in aggregate is associated with higher electricity consumption in a region, so the income elasticity is positive.

Elasticity is a proportional measure and may therefore be compared across different products or in different regions. Estimates of elasticities are imprecise, however, and may vary according to the source and methodology adopted, because the:

- consumer response may change over time
- estimated linear response may be a simplified representation of the true, non-linear response, and
- impact of the control variable (e.g. electricity price) may be imperfectly isolated from the impact of other, included or omitted variables.

Different classes of consumers will have different responses to price and income changes. Therefore each region's average elasticity is expected to be different in line with differences in the structure of each regional economy.

[42] See http://www.transend.com.au/Default.aspx?tabid=75

Table 4-38 lists the estimates of own price and income elasticity for each region. These latest estimates:

- derive from the forecasting models used to develop the energy and MD projections, and
- in most cases are supported by literature reviews of previous estimates.

See the regional Annual Planning Reports and the SASDO for more information.

Table 4-38—Long-run price elasticity estimates

Region	Own price elasticity	Income elasticity
Queensland	-0.29	n.a.
New South Wales	-0.16	0.67
Victoria	-0.38	1.15
South Australia	-0.25	1.01
Tasmania	-0.23	n.a.

4.11.8 Variation of demand and calculation of reference temperatures

TransGrid and AEMO (for Victoria and South Australia) use simulation procedures to determine MDs at the given 90%, 50%, and 10% POE levels. This means that New South Wales, Victorian, and South Australian MDs are not linked by the projection methodology to unique temperature events.

However, Powerlink and Transend use techniques that require the prior analysis of historical data to determine those temperatures that are uniquely associated with 90%, 50%, and 10% POE MDs. Table 4-39 and Table 4-40 list the temperatures used to prepare the MD projections for Queensland and Tasmania.

Table 4-39—Queensland daily average temperatures at associated POE levels (°C)

POE	NQ non-industrial (Townsville)	CQ non-industrial (Rockhampton)	SWQ (Toowoomba)	SEQ Brisbane (Archerfield)
10% summer	32.0	32.6	29.0	30.5
50% summer	30.4	30.7	27.0	28.4
90% summer	29.8	29.3	25.3	27.3
10% winter	25.7	10.2	4.7	9.6
50% winter	24.2	11.6	6.0	10.9
90% winter	23.2	12.9	7.0	12.3

Table 4-40—Tasmanian daily average temperatures at associated POE levels (°C Hobart)

POE	Summer	Winter
10%	7.7	1.2
50%	9.3	2.4
90%	10.3	3.4

4.11.9 Renewable energy contribution factors

Table 4-41 shows the assumed availability of wind farm capacity at times of regional MD.

Table 4-41—Wind farm contribution factors

Region	Summer	Winter
Queensland	0.000	0.000
New South Wales	0.050	0.050
Victoria	0.080	0.055
South Australia	0.030	0.010
Tasmania	0.000	0.000

4.11.10 Coincidence of regional maximum demand in the NEM

Coincidence of intra-regional demand

MDs at individual connection points within a region do not necessarily occur at the same time, due to a lack of uniformity and a degree of randomness in regional weather patterns and consumer behaviour. This is particularly the case for geographically large regions like Queensland. As a result, when preparing regional MD projections the forecasters account for the degree of coincidence between the MDs at connection points across a region (that is, to the extent to which local MDs occur at the same time).

Coincidence of inter-regional demand

MDs in regions generally occur at different times, for much the same reasons as MDs at individual connection points within a region occur at different times.

4.11.11 Demand-side participation survey and analysis of results

DSP refers to measures of short-term, market-driven demand reductions that AEMO includes in the supply-demand outlook. DSP has been established for a number of years by surveying demand response aggregators, network service providers, retailers and other market customers. The survey respondents were asked for confidential DSP MW values that could be regarded as ‘committed’ or ‘non-committed’. These amounts were then aggregated to create regional totals.

In 2010, a new procedure was undertaken that involved the following steps.

Specific National Metering Identifiers (NMIs) were collected by surveying demand response aggregators, network service providers (NSPs), retailers and other market customers. The NMIs collected were those of direct market customers, price-responsive retail customers, and those with specific demand response arrangements, including network support agreements.

The energy data associated with the NMIs was aggregated for each region for the period January 2008 to March 2010. Each regional energy series was then tested for its empirical relationship with extreme prices, using a price function equal to the NEM market price above $100 or else zero. Non-price related movements in the energy series, including regular time-varying movements, were simultaneously accounted for.

The estimated energy-price relationships were used to predict the energy series for each region on the basis of the NEM prices that actually occurred over the historical reference period. An alternative prediction was also prepared using a constant zero price scenario.

For each region, the difference between the above two predictions at critical times was defined as historical 'committed' DSP. 'Maximum potential' DSP was defined as the total identified price-responsive load. 'Non-committed' DSP was the difference between maximum potential and committed DSP.

Future DSP was identified by aggregating the amounts nominated by the same survey respondents who supplied the NMIs. These amounts were placed by the respondents into one of three categories: 'very likely', 'even chance', or 'extremely unlikely'. Medium, high, and low DSP scenario projections were generated based on the 'very likely' DSP starting-year amounts. These DSP projections should be regarded as being aligned with previously advised 'committed' DSP amounts.

See Section 4.10 for information about estimated historical DSP and projected future values for each region.

Chapter 5 – Generation Capacities

5.1 Summary

This chapter presents information about generation capacities in the National Electricity Market (NEM), which is based on the 2010 Australian Energy Market Operator (AEMO) survey of generators registered in the NEM concerning the capacities of existing generating units, generating units for which there have been commitments to construct, and planned plant retirements. The chapter also includes a general discussion about generation investment trends. Information about generation capacities is presented for each region.

See Appendix C for information about capacity factors of scheduled and semi-scheduled generation in each region.

Generation capacity projections for 2010/11

Table 5-1 lists the total regional capacity projections at the time of the summer and winter maximum demand (MD) for 2010/11. Generation capacity projections are used as a supply-demand outlook input (see Chapter 7 for more information).

Table 5-1—NEM generation capabilities, 2010/11

Region	Summer (MW) 2010/11	Winter (MW) 2011
Queensland	12,302	12,626
New South Wales	15,951	15,934
Victoria	10,741	11,304
South Australia	3,989	4,475
Tasmania	2,429	2,130
NEM Total	**45,412**	**46,469**

5.2 Generation investment trends

In addition to capacity projections, generation plant owners advise AEMO about the status of generation projects currently under development in each region. While the nature of generation investment (in terms of fuel sources and scale) varies from region to region, there is noticeable growth in gas-fired and renewable generation developments across the NEM. In contrast, there are few proposed coal-fired generation projects. This is consistent with the expectation that climate change policies are likely to drive greater investment in gas-fired generation and renewable energy (see Chapter 2 for more information).

Project proposals involve a range of projects at different stages of advancement. The ESOO refers to 'publicly announced proposals', 'advanced proposals' and 'committed projects' to represent three different stages of project development. AEMO only includes committed projects in the supply-demand outlook assessment.

Projects are classified based on AEMO's commitment criteria, which cover site acquisition, contracts for major components, planning approval, financing, and the date set for construction (see Table 5-2). Committed projects meet five of the commitment criteria, advanced proposals meet at least three, and publicly announced proposals meet less than three.

5.2.1 Proposed generation in the NEM

In Queensland there is approximately 1,300 MW of advanced or committed gas-fired generation. Queensland also has publicly announced projects across a range of fuel types, with over 500 MW from coal seam gas. New South Wales has a significant amount of proposed generation, including 11 gas-fired power stations (totalling 3,565 MW) and 12 wind farm projects (totalling 2,645 MW).

A significant amount of gas-fired generation (five power stations with a total capacity of 3,180 MW) has been proposed in Victoria, with some projects at an advanced or committed stage of development. In contrast, only one brown coal-fired plant has been proposed (an integrated brown coal gasification combined-cycle demonstration project), with an expected capacity of 550 MW.

South Australia has 20 proposed wind farm developments, totalling 2,309 MW, and a number of publicly announced gas-fired, coal-fired, and geothermal generation projects. Relative to other fuel types, the region also has a considerable amount of committed wind generation. There is one black coal project (570 MW).

Tasmania's proposed generation is exclusively renewable, with proposed wind capacity totalling 568 MW and an advanced proposal for a180 MW biomass pulp mill that is expected to be commissioned in 2013.

Table 5-2—Project commitment criteria

Category	Criteria
Site	The proponent has purchased/settled/acquired land (or legal proceedings have commenced) for the construction of the proposed development
Major components	Contracts for the supply and construction of the major components of plant or equipment (such as generators, turbines, boilers, transmission towers, conductors, and terminal station equipment) should be finalised and executed, including any provisions for cancellation payments
Planning consents/ construction approvals/EIS	The proponent has obtained all required planning consents, construction approvals, and licences, including completion and acceptance of any necessary environmental impact statements (EIS)
Finance	The financing arrangements for the proposal, including any debt plans, must have been concluded and contracts executed
Final construction date set	Construction of the proposal must either have commenced or a firm commencement date must have been set

In the 2010 ESOO, generation is categorised as:

- existing generation
- committed projects, or
- proposed projects, which are further identified as either:
  - advanced proposals, or
  - publicly announced proposals

Existing generation incorporates generation that is commissioned and operating as at 1 May 2010, and requires that the operator be a registered market participant.

Committed projects, **advanced proposals**, and **publicly announced proposals** refer to projects under development that AEMO has sufficient information about to enable classification.

The following abbreviations are used throughout this chapter to identify project status:

Description	Abbreviation
Committed project	C
Advanced proposal	Adv
Publicly announced proposal	Pub An

5.2.2 Generation projects – completed and committed

Table 5-3 lists scheduled and semi-scheduled generation projects the 2009 ESOO identified as committed that are now complete.

Table 5-3—Completed projects since 2009

Registered participant	Power station	Registered capacity (MW)	Fuel/technology
	Queensland		
ERM Power	Braemar 2	519	Coal seam gas
Origin Energy	Darling Downs	644	Gas - CCGT
	New South Wales		
Delta	Colongra	724	Gas
	Victoria		
AGL Hydro Partnership	Bogong	140	Water - Hydro
	South Australia		
AGL Energy	Hallett Stage 2 – Hallett Hill	71	Wind Farm
Pacific Hydro	Clements Gap	56.7	Wind Farm

Table 5-4 lists scheduled and semi-scheduled generation projects the 2009 ESOO identified as proposed that are now committed.

Table 5-4—Committed projects since 2009

Registered participant	Power station	Registered capacity (MW)	Fuel/technology	Expected completion
		Queensland		
QGC	Condamine	144	Gas - CCGT	Q3, 2010
		New South Wales		
Eraring Energy	Eraring – Upgrade	240	Steam turbine - Black Coal	2012/13
Snowy Hydro	Tumut 3 – Upgrade	300	Hydro	2011/12
		Victoria		
Origin Energy	Mortlake – Stage 1	567	Gas – CCGT	Q1, 2011

Registered participant	Power station	Registered capacity (MW)	Fuel/technology	Expected completion
AGL Energy	Oaklands Hill Wind Farm	67	Wind Farm	Q3, 2011
Loy Yang Marketing Management Company Pty Ltd	Loy Yang A upgrade	Extra 10 MW in winter, 20 MW in summer	Steam Turbine – Brown Coal	Q2, 2011
		South Australia		
AGL Energy	Hallett 4 – North Brown Hill Wind Farm	132	Wind Farm	mid-2011
AGL Energy	Hallett 5 – The Bluff Wind Farm	52.5	Wind Farm	Q4, 2011
Infigen Energy	Lake Bonney Stage 3 Wind Farm	39	Wind Farm	Q3, 2010
International Power	Port Lincoln – Expansion	23	Distillate – OCGT	mid-2010
Roaring 40s	Waterloo Wind Farm	111	Wind Farm	Q4, 2010
TRUenergy	Hallett GT – Expansion	23	Gas – OCGT	Q1, 2011
		Tasmania		
Hydro Tasmania	Tungatinah – Upgrade	9	Hydro	2013/14

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

Scheduled generation refers to any generating system with an aggregate nameplate capacity of 30 MW or more, unless it 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 capacity of 30 MW or greater. 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. The supply-demand outlook de-rates semi-scheduled wind generation capacities to account for firm contributions at the time of MD.

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

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

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

Generation capacity can be measured as either the:

- gross or **'as generated'** capacity measured at a generating unit's terminals, or
- net or **'sent-out'** capacity, allowing for the consumption of some of the generating unit's output by auxiliary equipment (used to help produce and transmit the electricity).

A generating system's registered capacity is the nominal megawatt (MW) capacity of the generating unit registered with the AEMO.

For the purposes of the ESOO and consistent with market systems, AEMO measures scheduled and semi-scheduled generation capacity on an 'as generated' basis. Non-scheduled generation is measured as sent-out because it can include co-generation plants, where the bulk of the generator's capacity is consumed by the local process. See Chapter 4, Section 4.2.1, for more information about the basis for measuring generation.

5.2.3 Additional capacity considerations

Temperature effects on generation

The actual level of generation available at any particular time will depend on a range of factors, such as age, outages, and wear, which will affect the maximum capacity. Another important factor with respect to output is the reduction in thermal efficiency with increasing temperature.

Temperature can affect plant generation capacities in different ways. Basing generation capacities on a region-specific reference temperature facilitates a more effective assessment of the capability of the available generation under weather conditions that are frequently associated with high demand.

To produce the supply-demand outlook, AEMO:

- uses historical data to estimate the typical weather conditions, and to determine reference temperatures that occur during times of 10% probability of exceedence (POE) MD in the major load centres for each region, and
- asks generators to provide generating unit capacities for summer and winter using common reference temperatures (which better represent temperatures expected during extreme, high-demand days).

Table 5-5 lists the common reference temperatures applied by AEMO. In general, the supply-demand balance is most tested during the summer, with the exception of Tasmania, where the highest demand periods occur during winter, and the highest summer demands occur during colder temperatures, resulting in a low summer reference temperature.

Table 5-5—Generation capacity reference temperatures

Region	Summer (°C)	Winter (°C)
Queensland	37	15
New South Wales	42	12
Victoria	41	8
South Australia	42.8	11
Tasmania	7.7	1.2

Thermal overload capacity

Some thermal generating systems (generation that burns fuel) can provide additional, short-term capacity that exceeds their registered capacity. Known as the thermal overload capacity, this often happens when there is low reserve or high prices (or both), and rarely exceeds 5% of the registered capacity.

5.2.4 Developing criteria for plant retirements

As part of its annual generator survey, AEMO obtains advice about planned plant retirements. Feedback from generator survey respondents indicates that firm retirement dates can be difficult to determine. To plan around potential plant retirements, AEMO is considering developing plant retirement criteria, which would operate in a similar manner to the generation project status criteria.

Plant retirements will be categorised as:

- a committed retirement
- an advanced retirement, or
- an announced retirement.

AEMO is considering the following retirement criteria to indicate the point at which generation can be considered to be shutting down:

- A financial commitment or contracts let for the demolition or scrapping of critical plant.
- Documented Board approval for shutdown.
- Formal notification to the network service provider/water supply/fuel supply and delivery/facility providers of the change of status of the plant.
- Formalised arrangements for the redeployment or retrenchment of operational staff consistent with the proposed shutdown.
- Firm dates for retirement have been communicated to the Australian Stock Exchange and shareholders.

Committed retirements would meet five of the retirement criteria, and advanced retirements would meet at least three. Publicly announced retirements would meet less than three criteria and apply to any plant where an announcement has been made about the intention to shut down.

AEMO welcomes feedback from stakeholders about these criteria. Comments can be submitted to the Executive General Manager, Planning, PO Box 3859, South Brisbane, QLD 4122.

5.3 Interconnector power flows

As an interconnected market, the NEM enables electricity transfers between adjacent regions across six interconnectors, depending on the physical transfer capacity of the interconnector.

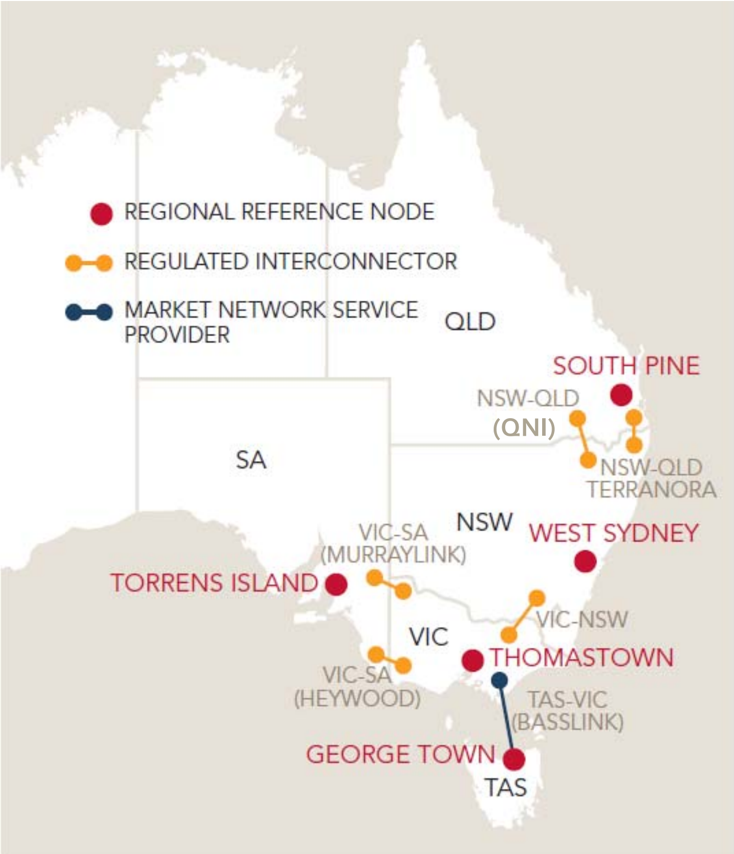
These interconnectors are as follows:

- QNI connects New South Wales and Queensland.
- Terranora (ex-Directlink) (in New South Wales) connects New South Wales and Queensland.
- VIC-NSW connects Victoria and New South Wales.
- Heywood connects South Australia and Victoria.

- Murraylink is a connection linking the Riverland region of South Australia and Victoria.
- Basslink connects Victoria and Tasmania.

Figure 5-1 shows the locations of the NEM interconnectors and regional reference nodes.

Figure 5-1—NEM interconnectors



Two types of interconnectors connect regions within the NEM:

- Regulated interconnectors, which must pass the Regulatory Test and be deemed to add net market value to the NEM, are eligible to receive fixed annual revenue that is collected as part of the network charges included in electricity customer accounts. Revenues are set by the Australian Energy Regulator (AER), and are based on the value of the asset, regardless of actual usage.
- Unregulated (or market) interconnectors derive revenue by purchasing energy in a lower price region and selling it to a higher price region (spot market trading), or by selling the rights to revenue generated by trading across the interconnector.

While NEM interconnectors can be either regulated or unregulated, Basslink is the only unregulated interconnector.

5.3.1 Historical interconnector power flows

Table 5-6 lists the energy imported and exported via each interconnector from 2004/05-2009/10. Figures for 2009/10 are calculated on a pro-rata basis from May 2010. In 2009/10, South Australia, Tasmania, and New South Wales were net importers of electricity from Victoria and Queensland.

The net imports show the magnitude and direction of power flows each year. Positive numbers indicate a net power flow in the direction indicated for each interconnector. Negative numbers indicate a net power flow in the opposite direction. For example, net imports via Basslink in 2008/09 were -2,570 GWh, demonstrating that net power flow was in the Victoria to Tasmania direction.

Table 5-6—Historical interconnector power flows

Financial year	Net imports (GWh)	Total imports (GWh)	Total exports (GWh)	Import average (MW)	Export average (MW)
Heywood - from Victoria to South Australia [1]					
2004/05	2,155	2,214	59	272	95
2005/06	2,339	2,374	35	285	83
2006/07	1,011	1,246	235	193	102
2007/08	131	657	526	140	129
2008/09	393	829	436	156	119
2009/10 pro-rata	750	1,068	318	179	114
Murraylink - from Victoria to South Australia [2]					
2004/05	267	305	38	46	22
2005/06	239	270	31	41	20
2006/07	-69	87	156	30	33
2007/08	-136	40	176	20	29
2008/09	-166	52	218	24	35
2009/10 pro-rata	-210	75	285	30	45
Terranora (ex-Directlink) - from New South Wales to Queensland [3]					
2004/05	-208	20	228	3	98
2005/06	-444	6	450	1	100
2006/07	-778	1	779	14	90
2007/08	-615	9	624	19	75
2008/09	-712	6	718	15	86
2009/10 pro-rata	-575	1	576	18	82
QNI - from New South Wales to Queensland [4]					
2004/05	-4,465	69	4,534	118	554
2005/06	-5,401	66	5,467	151	657
2006/07	-5,715	45	5,760	159	680
2007/08	-4,692	108	4,800	145	597
2008/09	-4,199	124	4,323	156	543
2009/10 pro-rata	-3,480	54	3,534	136	531
Basslink - from Tasmania to Victoria [5]					
2004/05	0	0	0	0	0
2005/06	-105	172	277	41	201
2006/07	-1,375	591	1,966	260	303
2007/08	-2,293	230	2,523	157	344
2008/09	-2,570	74	2,644	94	332
2009/10 pro-rata	-1,249	691	1,940	211	353
Victoria-New South Wales - from Victoria to New South Wales [6]					
2004/05	0	0	0	0	0
2005/06	0	0	0	0	0

Financial year	Net imports (GWh)	Total imports (GWh)	Total exports (GWh)	Import average (MW)	Export average (MW)
2006/07	0	0	0	0	0
2007/08	0	0	0	0	0
2008/09	941	2,099	1,158	427	301
2009/10 pro-rata	2,909	3,603	694	564	293

1. Imports refer to transfers from Victoria to South Australia. Exports refer to transfers from South Australia to Victoria
2. Imports refer to transfers from Victoria to South Australia. Exports refer to transfers from South Australia to Victoria
3. Imports refer to transfers from New South Wales to Queensland. Exports refer to transfers from Queensland to New South Wales
4. Imports refer to transfers from New South Wales to Queensland. Exports refer to transfers from Queensland to New South Wales
5. Imports refer to transfers from Tasmania to Victoria. Exports refer to transfers from Victoria to Tasmania. Basslink commenced operations in 2005/06
6. Imports refer to transfers from Victoria to New South Wales. Exports refer to transfers from New South Wales to Victoria. No data is available prior to 2008, because the region boundaries changed with the abolition of the Snowy region

5.4 Queensland

5.4.1 Existing and committed scheduled and semi-scheduled generation

Table 5-7 lists existing and committed generation in Queensland. Table 5-8 and Table 5-9 list projected scheduled and semi-scheduled generation capacities for winter and summer, respectively.

Table 5-7—Existing and committed scheduled and semi-scheduled generation - Queensland

Registered participant	Power station	Number of units and nameplate rating (MW)	Registered capacity (MW)	Plant type	Fuel
Ergon Energy Queensland Pty Ltd	Barcaldine GT	1 x 55	55	Gas Turbine	Natural Gas
Stanwell Corporation Limited	Barron Gorge	2 x 30	60	Hydro	Water
Braemar Power Project Pty Ltd	Braemar	3 x 168	504	Gas Turbine	Natural Gas
NewGen Braemar 2 Partnership	Braemar 2	3 x 165	519	Gas Turbine	Coal Seam Gas
CS Energy Limited	Callide B	2 x 350	700	Steam Turbine	Black Coal
Callide Power Trading Pty Ltd	Callide Power Plant	2 x 420	840	Steam Turbine	Black Coal
CS Energy Limited	Collinsville	3 x 32 1 x 33 1 x 66	195	Steam Turbine	Black Coal
Origin Energy Electricity Limited	Darling Downs	3 x 121(GTs) 1 x 280 (ST)	644	Combined Cycle (CCGT)	Natural Gas
Stanwell Corporation Limited	Gladstone	6 x 280	1,680	Steam Turbine	Black Coal
Stanwell Corporation Limited	Kareeya	3 x 21 1 x 18	81	Hydro	Water
CS Energy Limited	Kogan Creek	1 x 781	750	Steam Turbine	Black Coal
Stanwell Corporation Limited	Mackay GT	1 x 30	30	Gas Turbine	Fuel Oil

Registered participant	Power station	Number of units and nameplate rating (MW)	Registered capacity (MW)	Plant type	Fuel
Millmerran Energy Trader Pty Ltd	Millmerran	2 x 426	852	Steam Turbine	Black Coal
Origin Energy Electricity Limited	Mt Stuart GT	2 x 146 1 x 131	423	Gas Turbine	Fuel Oil
AGL Hydro Partnership	Oakey	2 x 141	282	Gas Turbine	Natural Gas/Fuel Oil
Origin Energy Electricity Limited	Roma GT	2 x 40	80	Gas Turbine	Natural Gas
Stanwell Corporation Limited	Stanwell	4 x 350	1,400	Steam Turbine	Black Coal
CS Energy Limited	Swanbank B	4 x 125	500	Steam Turbine	Black Coal
CS Energy Limited	Swanbank E	1 x 385	385	Combined Cycle (CCGT)	Natural Gas
Tarong Energy Corporation Limited	Tarong	4 x 350	1,400	Steam Turbine	Black Coal
Tarong Energy Corporation Limited	Tarong North	1 x 450	443	Steam Turbine	Black Coal
AGL Hydro Partnership	Townsville GT	1 x 165 1 x 82	242	Gas Turbine	Natural Gas
Tarong Energy Corporation Limited	Wivenhoe	2 x 250	500	Hydro	Water
Rio Tinto	Yarwun [1]	1 x 160	160	Cogeneration	Gas
Committed projects					
QGC Sales Qld Pty Ltd	Condamine	2 x 43 (GTs) 1 x 57 (ST)	144	Combined Cycle (CCGT)	Natural Gas

1. Yarwun is a non-scheduled generator, but has been included because it is required to comply with some of the obligations of a scheduled generator

Table 5-8—Winter aggregate scheduled and semi-scheduled generation - Queensland (MW)

Power station	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Class
Barcaldine GT	49	49	49	49	49	49	49	49	49	49	S
Barron Gorge	60	60	60	60	60	60	60	60	60	60	S
Braemar	504	504	504	504	504	504	504	504	504	504	S
Braemar 2	519	519	519	519	519	519	519	519	519	519	S
Callide A[1]	30	30	30	30	30	0	0	0	0	0	S
Callide B	700	700	700	700	700	700	700	700	700	700	S
Callide Power Plant	900	900	900	900	900	900	900	900	900	900	S
Collinsville[2]	187	187	187	187	187	187	187	187	187	187	S
Darling Downs	630	630	630	630	630	630	630	630	630	630	S
Gladstone	1,680	1,680	1,680	1,680	1,680	1,680	1,680	1,680	1,680	1,680	S
Kareeya	86	86	86	86	86	86	86	86	86	86	S
Kogan Creek	744	744	744	744	744	744	744	744	744	744	S
Mackay GT	32	32	32	32	32	0	0	0	0	0	S
Millmerran	852	852	852	852	852	852	852	852	852	852	S
Mt Stuart	415	415	415	415	415	415	415	415	415	415	S
Oakey GT	332	332	331	331	330	330	330	330	330	330	S
Roma GT	68	68	68	68	68	68	68	68	68	68	S
Stanwell Corporation	1,460	1,466	1,466	1,466	1,466	1,468	1,469	1,469	1,470	1,468	S

Power station	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Class
Swanbank B	120	0	0	0	0	0	0	0	0	0	S
Swanbank E	370	370	370	370	370	370	370	370	370	370	S
Tarong	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	S
Tarong North	443	443	443	443	443	443	443	443	443	443	S
Townsville GT	244	244	244	244	244	243	243	243	243	243	S
Wivenhoe	500	500	500	500	500	500	500	500	500	500	S
Yarwun[3]	166	166	166	166	166	166	166	166	166	166	NS
Committed projects											
Condamine	135	135	135	135	135	135	135	135	135	135	S
Total	**12,626**	**12,513**	**12,511**	**12,511**	**12,510**	**12,449**	**12,450**	**12,450**	**12,450**	**12,449**	

1. Callide A will be used in an oxy-firing trial before being shut down in summer 2015/16
2. Operation of Collinsville Power Station is currently contracted to CS Energy until August 2016. From 2016, Transfield Services intend to register as the market participant and will take over operations of the plant. The plant's operational profile may change according to market conditions
3. Yarwun is a non-scheduled generator, but has been included because it is required to comply with some of the obligations of a scheduled generator

Table 5-9—Summer aggregate scheduled and semi-scheduled generation - Queensland (MW)

Power station	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	Class
Barcaldine GT	49	49	49	49	49	49	49	49	49	49	S
Barron Gorge	60	60	60	60	60	60	60	60	60	60	S
Braemar	435	435	435	435	435	435	435	435	435	435	S
Braemar 2	495	495	495	495	495	495	495	495	495	495	S
Callide A [1]	30	30	30	30	30	0	0	0	0	0	S
Callide B	700	700	700	700	700	700	700	700	700	700	S
Callide Power Plant	900	900	900	900	900	900	900	900	900	900	S
Collinsville [2]	187	187	187	187	187	187	187	187	187	187	S
Darling Downs	605	605	605	605	605	605	605	605	605	605	S
Gladstone	1,680	1,680	1,680	1,680	1,680	1,680	1,680	1,680	1,680	1,680	S
Kareeya	86	86	86	86	86	86	86	86	86	86	S
Kogan Creek	724	724	724	724	724	724	724	724	724	724	S
Mackay GT	27	27	27	27	27	27	0	0	0	0	S
Millmerran	760	852	852	852	852	852	852	852	852	852	S
Mt Stuart	387	387	387	387	387	387	387	387	387	387	S
Oakey GT	275	275	275	274	273	273	273	273	273	273	S
Roma GT	54	54	54	54	54	54	54	54	54	54	S
Stanwell Corporation	1,397	1,404	1,404	1,404	1,405	1,407	1,407	1,406	1,406	1,405	S
Swanbank B	240	120	0	0	0	0	0	0	0	0	S
Swanbank E	350	350	350	350	350	350	350	350	350	350	S
Tarong	1,400	1,400	1400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	S
Tarong North	443	443	443	443	443	443	443	443	443	443	S
Townsville GT	235	235	235	235	235	234	234	233	233	233	S
Wivenhoe	500	500	500	500	500	500	500	500	500	500	S

Power station	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	Class
Yarwun [3]	146	146	146	146	146	146	146	146	146	146	NS
Committed projects											
Condamine	135	135	135	135	135	135	135	135	135	135	S
Total	**12,302**	**12,280**	**12,160**	**12,159**	**12,159**	**12,129**	**12,102**	**12,101**	**12,101**	**12,099**	

1. Callide A will be used in an oxy-firing trial before being shut down in summer 2015/16
2. Operation of Collinsville power station is currently contracted to CS Energy until August 2016. From 2016, Transfield Services intend to register as the market participant and will take over operations of the plant. The plant's operational profile may change according to market conditions
3. Yarwun is a non-scheduled generator, but has been included because it is required to comply with some of the obligations of a scheduled generator

5.4.2 Changes since the 2009 ESOO (existing generation)

ERM Power advises that Braemar 2 Power Station has revised its capacity from 462 MW to 495 MW during summer due to an output re-evaluation. ERM Power is the new owner of Braemar 2 Power Station, which was previously owned by Babcock and Brown.

Millmerran Energy Trader advises that Millmerran Power Station is expected to reduce its capacity from 852 MW to 760 MW in summer 2010/11 due to issues with turbine blades that are expected to be resolved before winter 2011.

Origin Energy advises that the Darling Downs Power Station is now complete. The station will be capable of generating up to 630 MW in winter and 605 MW in summer. The 2009 ESOO identified this as a committed project.

5.4.3 Committed project developments

QGC advises that Condamine Power Station is a committed project currently in its commissioning phase. The project is likely to be completed before the end of 2010.

Rio Tinto advises that its application for the Yarwun Cogen Gas Turbine to be classified as a non-scheduled project has been approved by AEMO. Although Yarwun is now a non-scheduled generator, it is still required to comply with some of the obligations of a scheduled generator. The project is scheduled for completion in July 2010.

5.4.4 Plant limitations

The capacity of some plants may be restricted depending on water availability for generation or cooling.

Millmerran Energy Trader advises that the Millmerran Power Station is experiencing LP turbine blade issues limiting maximum backpressure, which is expected to be resolved in 2011.

Tarong Energy advises that Wivenhoe Power Station's maximum available daily energy is approximately 3,000 MWh-4,000 MWh.

5.4.5 Plant retirements

CS Energy advises that Swanbank B Unit 2 will be mothballed from June 2010, Unit 1 from April 2011, and Unit 3 from April 2012. Unit 4 was mothballed in May 2010.

Stanwell Corporation advises that Mackay GT Power Station has a tentative retirement date scheduled for early 2016. Stanwell Corporation is currently assessing the power station's future.

5.4.6 Historical generation levels and performance

Table 5-10 lists historical Queensland scheduled and semi-scheduled generation output from 2005/06-2009/10. Figures for 2009/10 are calculated on a pro-rata basis from May 2010.

Table 5-10—Historical scheduled and semi-scheduled generation (GWh) - Queensland

Power station	2005/06	2006/07	2007/08	2008/09	2009/10 pro-rata
Barcaldine	141	100	77	9	11
Barron Gorge	100	241	262	270	160
Braemar	32	1,301	1,951	1,861	1,697
Braemar 2	0	0	0	104	1,748
Callide	5,352	6,875	5,668	5,917	5,819
Callide B	5,399	5,128	4,626	3,862	4,888
Collinsville	573	577	755	542	414
Condamine	0	0	0	0	210
Darling Downs	0	0	0	0	425
Gladstone	8,122	8,820	8,455	7,990	7,435
Kareeya	395	639	506	510	341
Kogan Creek	0	150	4,665	5,273	4,564
Mackay GT	1	0	1	2	2
Millmerran	6,246	6,489	6,984	6,189	6,249
Mt Stuart	20	45	74	29	43
Oakey	4	25	28	30	42
Roma GT	19	36	71	233	280
Stanwell	10,213	9,560	9,414	8,489	8,804
Swanbank B	2,294	2,144	2,134	1,927	1,882
Swanbank E GT	1,585	2,305	2,117	2,203	2,084
Tarong	11,308	8,537	4,753	7,741	8,051
Tarong North	3,672	3,208	2,856	3,233	2,108
Townsville GT	1,627	1,573	1,350	1,143	1,393
Wivenhoe	50	131	126	34	46
Total	**57,153**	**57,884**	**56,873**	**57,591**	**58,696**

5.4.7 Advanced and publicly announced proposals

AEMO sought information from generators and project proponents about the status of generation projects under development. Some companies provide AEMO with information that is commercial in confidence. Where this occurs, AEMO publishes as much publicly available information as possible.

Table 5-11 lists information about proposed generation projects in Queensland.

More detailed information about advanced proposals includes the following:

- **Origin Energy** advises that Spring Gully Power Station is an advanced proposal. The new gas-fuelled CCGT is expected to comprise four units and operate as scheduled generation. The proposed site is located on a coal seam gas field owned and operated by Origin Energy. There is no firm commissioning date as yet. This project was reported as an advanced proposal in the 2009 ESOO.

See Section 5.4.3 for information about committed project developments.

Table 5-11—Advanced and publicly announced proposals – Queensland

Company/operator	Project	Fuel/ technology	Capacity (MW)	Commissioning date	Site	Major comp'ts	Planning consents/ construction approval/ EIS	Finance	Firm construct date Set	Status	Class
AGL Energy	Crows Nest Wind Farm	Wind Turbine	150	TBA	-	-	-	-	-	Pub An	SS
CS Energy	Swanbank F	Gas/ CCGT	400	TBA	✓	-	-	-	-	Pub An	S
ERM Power	Braemar 3	Gas/ OCGT	500	Q1, 2013	✓	✓	-	-	-	Pub An	S
Origin Energy	Darling Downs Stage 2	Coal Seam Gas/ CCGT	519	TBA	✓	-	-	✓	-	Pub An	S
Origin Energy	Spring Gully	Gas/ CCGT	1000	TBA	✓	-	✓	✓	-	Adv	S
Stanwell Corporation	Burdekin Falls Dam Hydro Power Station	Hydro	35	2013-14	✓	-	-	-	-	Pub An	SS
Stanwell Corporation	Wandoan Power Project	Black coal/ IGCC with CCS	334	2015-16	✓	-	-	-	-	Pub An	S
Transfield Services	Bowen Wind Farm	Wind Turbine	101	Q4, 2015	-	-	-	-	-	Pub An	SS
Transfield Services	Crediton Wind Farm	Wind Turbine	40	Q4, 2016	-	-	-	-	-	Pub An	SS
Transfield Services	High Road Wind Farm	Wind Turbine	50	Q4, 2012	-	-	-	-	-	Pub An	SS
Bow Energy	Blackwater Power Station	Coal Seam Gas	30	TBA	✓	✓	-	✓	-	Adv	NS
Transfield Services	Windy Hill II Wind Farm	Wind Turbine	13	Q4, 2016	-	-	-	-	-	Pub An	NS

5.4.8 Non-scheduled generation

Table 5-12 lists information about non-scheduled generation in Queensland.

Table 5-12—Existing and committed non-scheduled generation - Queensland

Power station	Survey respondent	Fuel/technology	Capacity (MW)	Anticipated capacity for winter MD (MW)	Anticipated capacity for summer MD (MW)
KRC Castlemaine Cogen	AGL Energy	Thermal Gas	5	3	1
ISIS Central Sugar Mill Cogen	AGL Energy	Thermal - Bagasse	25	0	0
German Creek	AGL Energy	Thermal - Landfill Gas	32	15	15
Suncoast Gold Macadamias	AGL Energy	Biomass	2	0	0
Roghan Road	AGL Energy	Thermal - Landfill Gas	2	0	0
Daandine	Country Energy	Thermal – Coal Seam Methane	33	29	29
Oaky Creek	Country Energy	Thermal - Landfill Gas	20	19	14
Rochedale	Country Energy	Thermal - Landfill Gas	3	2	2
Whitwood Rd	Country Energy	Thermal - Landfill Gas	1	1	1
Invicta Mill	CSR	Thermal - Bagasse	39	38	4
Pioneer Sugar Mill	CSR	Biomass	68	60	48
Victoria Mill	CSR	Bagasse	12	12	11
Macknade Mill	CSR	Bagasse	8	8	7
Kalamia Mill	CSR	Bagasse	9	9	7
Inkerman Mill	CSR	Bagasse	11	11	9
Plane Creek Mill	CSR	Bagasse	14	13	13
Moranbah North Power Station	EDL	Reciprocating - Landfill Gas	46	42	42
Browns Plains	EDL	Landfill Gas	2	2	2
Rocky Point Cogeneration Plant	Rocky Point Green Power	Biomass	28	16	16
Kareeya 5	Stanwell Corporation	Hydro	7	7	7
Wivenhoe Small Hydro	Stanwell Corporation	Hydro	5	4	4
Tarong Gas Turbine	Tarong Energy	Gas Turbine	15	15	15
Windy Hill Wind Farm	Transfield Services	Wind	12	3	3
Veolia Ti Tree Bio Reactor	Veolia Environmental Services	Landfill Methane Gas	2	2	2
Committed non-scheduled generation					
Yarwun [1]	Rio Tinto	Gas/Cogeneration	160	166	146

1. Yarwun is a non-scheduled generator, but is required to comply with some of the obligations of a scheduled generator

5.5 New South Wales

5.5.1 Existing and committed scheduled and semi-scheduled generation

Table 5-13 lists existing and committed generation in New South Wales. Table 5-14 and

Table 5-15 list projected scheduled and semi-scheduled generation capacities for winter and summer, respectively.

Table 5-13—Existing and committed scheduled and semi-scheduled generation - New South Wales

Registered participant	Power station	Number of units and nameplate rating (MW)	Registered capacity (MW)	Plant type	Fuel
Macquarie Generation	Bayswater	4 x 660	2,640	Steam Turbine	Black Coal
Snowy Hydro Limited	Blowering	1 x 70	70	Hydro	Water
Delta Electricity	Colongra	4 x 181	724	Gas Turbine	Natural Gas
Eraring Energy	Eraring	4 x 660	2,640	Steam Turbine	Black Coal
Snowy Hydro Limited	Guthega	2 x 30	60	Hydro	Water
Eraring Energy	Hume (NSW)	1 x 29	29	Hydro	Water
Macquarie Generation	Hunter Valley	2 x 25	50	Gas Turbine	Fuel Oil
Macquarie Generation	Liddell	4 x 500	2,000	Steam Turbine	Black Coal
Delta Electricity	Mount Piper	1 x 700 1 x 660	1,360	Steam Turbine	Black Coal
Delta Electricity	Munmorah	2 x 300	600	Steam Turbine	Black Coal
Redbank Project Pty Ltd	Redbank	1 x 150	150	Steam Turbine	Black Coal
Eraring Energy	Shoalhaven	2 x 80 2 x 40	240	Hydro	Water
Marubeni Australia Power Services Pty Ltd	Smithfield	3 x 38 1 x 62	160	Steam Turbine	Natural Gas/Waste heat
TRUenergy Pty Ltd	Tallawarra	1 x 460	460	Combined Cycle Gas Turbine	Natural Gas
Snowy Hydro Limited	Tumut 3	6 x 250	1,500	Hydro	Water
Snowy Hydro Limited	Upper Tumut	4 x 82 4 x 72	616	Hydro	Water
Origin Energy Uranquinty Power Pty Ltd	Uranquinty	4 x 166	664	Gas Turbine	Natural Gas
Delta Electricity	Vales Point	2 x 660	1,320	Steam Turbine	Black Coal
Delta Electricity	Wallerawang	2 x 500	1,000	Steam Turbine	Black Coal

Table 5-14—Winter aggregate scheduled and semi-scheduled generation - New South Wales (MW)

Power station	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Class
Bayswater	2,760	2,760	2,760	2,760	2,760	2,760	2,760	2,760	2,760	2,760	S
Blowering	40	40	40	40	40	40	40	40	40	40	S
Colongra GT	724	724	724	724	724	724	724	724	724	724	S
Eraring[1]	2,100	2,160	2,880	2,880	2,880	2,880	2,880	2,880	2,880	2,880	S

Power station	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Class
Guthega	60	60	60	60	60	60	60	60	60	60	S
Hume (NSW)[2]	0	0	0	0	0	0	0	0	0	0	S
Hunter Valley	50	50	50	50	50	50	50	50	50	50	S
Liddell	2,090	2,090	2,090	2,090	2,090	2,090	2,090	2,090	2,090	2,090	S
Mt Piper	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	S
Munmorah[3]	600	600	600	600	0	0	0	0	0	0	S
Redbank	150	150	150	150	150	150	150	150	150	150	S
Shoalhaven	240	240	240	240	240	240	240	240	240	240	S
Smithfield	160	160	160	160	160	160	160	160	160	160	S
Tallawarra	460	460	460	460	460	460	460	460	460	460	S
Tumut 3	1,500	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	S
Upper Tumut	616	544	534	534	544	616	616	616	616	616	S
Uranquinty	664	664	664	664	664	664	664	664	664	664	S
Vales Pt	1,320	1,320	1,320	1,320	1,320	1,320	1,320	1,320	1,320	1,320	S
Wallerawang	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	S
Total	**15,934**	**16,222**	**16,932**	**16,932**	**16,342**	**16,414**	**16,414**	**16,414**	**16,414**	**16,414**	

1. Eraring's capacity includes the committed project to upgrade all four unit capacities by 60 MW, bringing the total to 2,880 MW by summer 2012/13
2. Hume has two units located near the Vic-NSW border. One unit is represented as being in Victoria, the other in New South Wales. Output can be dispatched to either New South Wales or Victoria or both
3. Munmorah Unit 3 will be on reserve from August 2010. Munmorah Unit 4 is on three month recall

Table 5-15: Summer aggregate scheduled and semi-scheduled generation - New South Wales (MW)

Power station	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	Class
Bayswater	2,720	2,720	2,720	2,720	2,720	2,720	2,720	2,720	2,720	2,720	S
Blowering	40	40	40	40	40	40	40	40	40	40	S
Colongra GT	668	668	668	668	668	668	668	668	668	668	S
Eraring[1]	2,040	2,820	2,880	2,880	2,880	2,880	2,880	2,880	2,880	2,880	S
Guthega	60	60	60	60	60	60	60	60	60	60	S
Hume (NSW)[2]	11	12	29	29	29	29	29	29	29	29	S
Hunter Valley	44	44	44	44	44	44	44	44	44	44	S
Liddell	2,075	2,075	2,075	2,075	2,075	2,075	2,075	2,075	2,075	2,075	S
Mt Piper	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	S
Munmorah[3]	600	600	600	600	0	0	0	0	0	0	S
Redbank	145	145	145	145	145	145	145	145	145	145	S
Shoalhaven	240	240	240	240	240	240	240	240	240	240	S
Smithfield	160	160	160	160	160	160	160	160	160	160	S
Tallawarra	422	422	422	422	422	422	422	422	422	422	S
Tumut 3	1,750	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	S
Upper Tumut	616	616	616	616	544	616	616	616	616	616	S
Uranquinty	640	640	640	640	640	640	640	640	640	640	S
Vales Pt	1,320	1,320	1,320	1,320	1,320	1,320	1,320	1,320	1,320	1,320	S
Wallerawang	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	S

Power station	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	Class
Total	15,951	16,782	16,859	16,859	16,187	16,259	16,259	16,259	16,259	16,259	

1. Eraring's capacity includes the committed project to upgrade all four unit capacities by 60 MW, bringing the total to 2,880 MW by summer 2012/13
2. Hume has two units located near the Vic-NSW border. One unit is represented as being in Victoria, the other in New South Wales. Output can be dispatched to either New South Wales or Victoria or both
3. Munmorah Unit 3 will be on reserve from August 2010. Munmorah Unit 4 is on three month recall

5.5.2 Changes since the 2009 ESOO (existing generation)

Delta Electricity advises that Colongra Power Station revised its capacity from 668 MW to 724 MW during winter and from 560 MW to 668 MW during summer due to an output re-evaluation. The capacity during summer assumes fuel oil is the primary fuel. If gas is the primary fuel then the capacity will be 648 MW during summer.

Eraring Energy advises the following:

- Eraring Power Station will have upgrades to all four units, increasing each unit's capacity by 60 MW, bringing the total capacity to 2,880 MW on completion. Scheduled outages of each unit are included in the yearly capacities and all work is expected to completed by summer 2012/13.
- Hume Power Station has a capacity of 29 MW, but has expected capacities of 11 MW during summer 2010/11 and 12 MW during summer 2011/12, to reflect output limitations resulting from a dependency on the available water head and irrigation water release requirements.

Snowy Hydro advises the following:

- Blowering Power Station revised its capacity from 70 MW to 40 MW due to changes in releases controlled by State Water.
- Tumut 3 Power Station revised its capacity from 1,500 MW to 1,800 MW due to a major overhaul program including installation of new runners, resulting in all six units increasing their capacity by 50 MW. Scheduled outages necessary for the overhaul program have had timing revisions, which is reflected in capacity variations until summer 2011/12.
- Upper Tumut Power Station revised the timing of scheduled outages due to maintenance, which has been reflected in variations in capacity until summer 2015/16 when work on all eight units is expected to be complete.

TRUenergy advises that Tallawarra Power Station revised its capacity from 435 MW to 460 MW during winter based on operational experience.

5.5.3 Committed project developments

There are no scheduled or semi-scheduled generation projects in New South Wales currently classified as committed according to AEMO's commitment criteria.

Eraring Energy advises that the upgrade to the four Eraring Power Station units is a committed project. Upgrades for Units 2 and 3 were reported as committed projects in the 2009 ESOO. Upgrades for Units 1 and 4 were reported as advanced proposals. Work on each of the four units will occur one by one and is expected to be completed by summer 2012/13.

Snowy Hydro advises the following:

- The upgrade to all six units of Tumut 3 Power Station is a committed project. AEMO has been advised that work on four units has been completed and work on the remaining units is expected to be completed by summer 2011/12.
- The Jounama Mini Hydro is a non-scheduled hydroelectric plant, and is expected to be commissioned in the third quarter of 2010.

Energy Response advises that the Bankstown Sports Club is a non-scheduled, liquid-fuelled plant, and is expected to be commissioned in the third quarter of 2010.

The GPT Group advises that the Charlestown Square Cogeneration Plant is a non-scheduled, gas-fuelled plant, and is expected to be commissioned in the fourth quarter of 2010.

5.5.4 Plant limitations

The capacity of some plants may be restricted depending on water availability for generation or cooling.

Delta Electricity advises that Vales Point Power Station may experience lake temperature limitations during summer.

Eraring Energy advises the following:

- Hume Power Station is expected to be unavailable in winter. Generation in summer is affected by water releases for irrigation purposes, which are controlled by the Murray Darling Basin Commission. Hume Power Station has two units that may be dispatched to either New South Wales or Victoria or both. AEMO has reported the power station's data as if one unit was a generator in New South Wales and the other a generator in Victoria.
- Eraring Power Station has constructed a temporary reservoir to alleviate cooling water issues, but there may still be restrictions during the period November-March.

5.5.5 Plant retirements

Delta Electricity advises that Munmorah Power Station will be available until winter 2014, which is consistent with previous expectations. Delta Electricity is currently assessing the power station's future.

5.5.6 Historical generation levels and performance

Table 5-16 lists historical New South Wales scheduled and semi-scheduled generation output from 2005/06-2009/10. Figures for 2009/10 are calculated on a pro-rata basis from May 2010.

Table 5-16 - Historical scheduled and semi-scheduled generation (GWh) - New South Wales

Power station	2005/06	2006/07	2007/08	2008/09	2009/10 pro-rata
Bayswater	17,632	15,306	16,523	16,960	16,279
Blowering	199	120	35	69	72
Colongra	0	0	0	3	171
Eraring	14,265	17,551	17,353	15,494	14,281
Guthega	126	67	113	107	159
Hume	154	28	10	20	60
Hunter Valley GT	1	0	0	1	0
Liddell	10,450	11,310	11,254	11,578	9591
Mt Piper	9,770	9,872	9,753	8,837	9516
Munmorah	1,524	2,094	2,373	2,480	801
Redbank	1,063	1,140	1,180	770	1,010
Shoalhaven	52	46	22	33	7
Smithfield Energy Facility	1,017	1,025	995	1,033	1,014
Tallawarra	0	0	0	799	2,356
Tumut 1	2,127	917	895	603	801

Power station	2005/06	2006/07	2007/08	2008/09	2009/10 pro-rata
Tumut 3	680	867	1081	624	473
Uranquinty	0	0	0	195	337
Vales Point B	6,012	6,465	7,785	8,904	8,337
Wallerawang C	6,041	5,006	5,795	5,183	4,305
Total	**71,113**	**71,814**	**75,167**	**73,693**	**69,570**

5.5.7 Advanced and publicly announced proposals

AEMO sought information from generators and project proponents about the status of generation projects under development. Some companies provide AEMO with information that is commercial in confidence. Where this occurs, AEMO publishes as much publicly available information as possible.

Table 5-17 lists information about proposed generation projects in New South Wales.

More detailed information about advanced proposals includes the following:

- **Acciona Energy** advises that Gunning Wind Farm is now an advanced proposal, and is expected to operate as semi-scheduled generation. Comprising 31 turbines with a capacity of 46.5 MW, it is expected to be commissioned by July 2011 and will connect to Country Energy's distribution network. The 2009 ESOO reported this as a publicly announced proposal.
- **AGL Energy** advises that Leaf's Gully Power Station is now an advanced proposal, and is expected to operate as scheduled generation. Comprising two gas-fuelled units with a total capacity of 360 MW, the expected date of commissioning has not been announced. The 2009 ESOO reported this as a publicly announced proposal.
- **Infigen Energy** advises that Woodlawn Wind Farm is now an advanced proposal, and is expected to operate as semi-scheduled generation. Comprising 20 wind turbines with a combined capacity of 42 MW, it is expected to be commissioned by March 2011. The 2009 ESOO reported this as a publicly announced proposal.

More detailed information about publicly announced proposals, which is incorporated for proposals of 2,000 MW or more, includes the following:

- **Delta Electricity** advises that Mount Piper Units 3 and 4 are under development, and will potentially deliver an additional 2,000 MW, either through the development of five gas-fired, 400 MW combined-cycle units by 2014, or two coal-fired, 1,000 MW super-critical units by 2016. The 2009 ESOO reported the coal-fired option as a publicly announced project.
- **Macquarie Generation** advises that a Major Projects Application was submitted to the New South Wales Government on 19 June 2009 for a series of advanced technology, power-generation units totalling 2,000 MW, to be erected at the existing Bayswater site. The fuel type has not yet been determined but will be either black coal or natural gas. Concept Approval was granted on 12 January 2010. This approval is not a Development Consent, and no date has been set for developing the site.

See Section 5.5.3 for information about committed project developments.

Table 5-17—Advanced and publicly announced proposals – New South Wales

Company/operator	Project	Fuel/ technology	Capacity (MW)	Commissioning date	Site	Major comp'ts	Planning consents / construction approval / EIS	Finance	Firm construct date Set	Status	Class
Acciona Energy	Gunning Wind Farm	Wind Turbine	46.5	Q3, 2011	✓	-	✓	-	✓	Adv	SS
AGL Energy	Dalton - NSW	Gas/ OCGT	1,160	Q4, 2013	✓	-	-	✓	-	Pub An	S
AGL Energy	Leafs Gully	Gas/ OCGT	360	TBA	✓	-	✓	✓	-	Adv	S
Delta Electricity	Bamarang	Gas/ CCGT or OCGT	400 or 300	2014	✓	-	✓	-	-	Pub An	S
Delta Electricity	Marulan	Gas/ CCGT or OCGT	450 or 350	2014	✓	-	✓	-	-	Pub An	S
Delta Electricity	Mount Piper 3&4 - Coal	Black coal/ USC or gas/ CCGT	2,000	2016 or 2014	✓	-	✓	-	-	Pub An	S
Delta Electricity	Munmorah Rehabilitation	Black coal or gas	700	2014	✓	-	-	-	-	Pub An	S
Epuron	Gullen Range Wind Farm	Wind Turbine	167.9	TBA	✓	-	-	-	-	Pub An	SS
Epuron	Silverton Wind Farm	Wind Turbine	1,256	TBA	✓	-	✓	-	-	Pub An	SS
ERM Power	Wellington	Gas/ OCGT	640	Q3, 2013	✓	-	✓	-	-	Pub An	S
Infigen	Woodlawn Wind Farm	Wind Turbine	42	Q1, 2011	✓	✓	✓	-	✓	Adv	SS
International Power	Buronga	Gas/ OCGT	120-150	TBA	-	-	-	-	-	Pub An	S
International Power	Parkes Peaking Power Plant	Gas/ OCGT	150	TBA	-	-	-	-	-	Pub An	S
Macquarie Generation	Bayswater B	Black coal or gas	2,000	2014	✓	-	-	-	-	Pub An	S
Macquarie Generation	Tomago GT	Gas/ OCGT	TBA	TBA	✓	-	✓	-	-	Pub An	S
Origin Energy	Conroys Gap Wind Farm	Wind Turbine	30	TBA	✓	-	✓	-	-	Pub An	SS
Origin Energy	Snowy Plains Wind Farm	Wind Turbine	30	TBA	✓	-	✓	-	-	Pub An	SS
Origin Energy	Yass Wind Farm	Wind Turbine	304	TBA	✓	-	-	-	-	Pub An	SS
RES	Taralga Wind Farm	Wind Turbine	122	2011-2012	✓	-	✓	-	-	Pub An	SS

Company/operator	Project	Fuel/ technology	Capacity (MW)	Commissioning date	Site	Major comp'ts	Planning consents / construction approval / EIS	Finance	Firm construct date Set	Status	Class
Transfield Services	Collector Wind Farm	Wind Turbine	149	Q4, 2016	-	-	-	-	-	Pub An	SS
TRUenergy	Tallawarra B	Gas/ OCGT	450	TBA	✓	-	-	-	-	Pub An	S
Union Fenosa	Crookwell 2 Wind Farm	Wind Turbine	92	Q3, 2012	✓	-	✓	-	-	Pub An	SS
Union Fenosa	Crookwell 3 Wind Farm	Wind Turbine	45-75	Q1,2013	✓	-	-	-	-	Pub An	SS
Union Fenosa	Paling Yards Wind Farm	Wind Turbine	90-150	Q1, 2015	✓	-	-	-	-	Pub An	SS
Wind Prospect	Boco Rock Wind Farm	Wind Turbine	270	Q1, 2012	✓	-	-	-	-	Pub An	SS
Eastern Star	Wilga Park 'A' Power Station	Gas	3	Q2, 2011	✓	-	✓	-	-	Pub An	NS
Eastern Star	Wilga Park 'B' Power Station	Gas	29.4	Q3, 2011 to Q4, 2011	✓	-	✓	-	-	Pub An	NS
Energy Australia	Woodlawn Bioreactor - Units 4-6	Landfill gas/ Thermal	1 MW per unit	Q4, 2011 Q2, 2014	✓	-	✓	✓	✓	Adv	NS
Energy Australia	Woodlawn Bioreactor - Units 7-12	Landfill gas/ Thermal	1 MW per unit	Q3, 2015 Q4, 2021	✓	-	-	-	-	Pub An	NS
Energy Response	Club Merrylands	Liquid Fuel	0.8	Q2, 2010	✓	✓	✓	✓	-	Adv	NS

5.5.8 Non-scheduled generation

Table 5-18 lists information about non-scheduled generation in New South Wales.

Table 5-18—Existing and committed non-scheduled generation - New South Wales

Power station	Survey respondent	Fuel/technology	Capacity (MW)	Anticipated capacity for winter MD (MW)	Anticipated capacity for summer MD (MW)
Burrendong Hydro Power Station	AGL Energy	Hydro	15	0	2
Copeton Hydro Power Station	AGL Energy	Hydro	24	0	8
Eastern Creek	AGL Energy	Thermal - Landfill Gas	10	7	7
Glenbawn Hydro Power Station	AGL Energy	Hydro	6	0	1
Grange Avenue	AGL Energy	Thermal - Landfill Gas	2	1	1
Jacks Gully	AGL Energy	Thermal - Landfill Gas	3	1	1
Pindari Hydro Power Station	AGL Energy	Hydro	7	0	1
West Nowra	AGL Energy	Thermal - Landfill Gas	1	0	0
Blayney Wind Farm	Country Energy	Wind	10	9	9
Broken Hill GT	Country Energy	Gas	50	50	40
Burrendong Dam	Country Energy	Hydro	9	0	0
Crookwell Wind Farm	Country Energy	Wind	5	4	4
Earth Power Biomass	Country Energy	Biomass	**4**	**2**	**2**
Lake Keepit	Country Energy	Hydro	5	0	0
Lucas Heights II Stage II	Country Energy	Thermal – Landfill Gas	18	4	4
Nymboida Power Station	Country Energy	Hydro	8	0	0
Oaky Power Station	Country Energy	Hydro	4	2	4
Teralba Power Station	Country Energy	Methane Gas	8	2	2
Broadwater	Delta Electricity	Thermal-Landfill Gas	30	41	33
Condong	Delta Electricity	Thermal-Landfill Gas	30	34	34
Wilga Park ‘A’ Power Station	Eastern Star	Gas	12	4	4
Mugga Lane	EDL	Landfill Gas	3	3	2
Appin Power Plant	EDL	Gas (Methane)	56	47	39
Lucas Heights II Power Plant	EDL	Thermal-Landfill Gas	13	12	11
Tower Power Plant	EDL	Thermal-Landfill Gas	41	35	29
Lucas Heights I	EDL	Landfill Gas	5	5	4
Woodlawn Bioreactor Energy Generation Station	Energy Australia	Thermal-Landfill Gas	7	2	2
Western Suburbs League Club (Campbelltown) Plant	Energy Response	Diesel	1	1	1
Wests Illawarra Leagues Club	Energy Response	Liquid Fuel	1	1	1
Glennies Creek	Envirogen	Gas	13	10	10
Tahmoor Power Station	Envirogen	Gas	7	7	7
Brown Mountain	Eraring Energy	Hydro	5	5	5

Power station	Survey respondent	Fuel/technology	Capacity (MW)	Anticipated capacity for winter MD (MW)	Anticipated capacity for summer MD (MW)
Burrinjuck Power Station	Eraring Energy	Hydro	28	5	5
Eraring Gas Turbine	Eraring Energy	Gas Turbine	42	40	33
Warragamba Power Station	Eraring Energy	Hydro	50	0	0
Capital Wind Farm	Infigen Energy	Wind	140	140	0
Awaba Power Station	Infratil Energy	Biomass	1	1	1
Hunter Economic Zone	Infratil Energy	Diesel	29	29	29
Eastern Creek 2 Gas Utilisation Facility	LMS Generation	Thermal - Landfill Gas	10	8	8
Summer Hill	LMS Generation	Thermal - Landfill Gas	2	2	2
Cullerin Range Wind Farm	Origin Energy	Wind	30	30	30
The Drop	Pacific Hydro	Hydro	3	0	0
Jindabyne Small Hydro Power Station	Snowy Hydro	Hydro	1	1	1
Committed non-scheduled generation					
Bankstown Sports Club	Energy Response	Liquid Fuel	2	1	2
Jounama Mini Hydro	Snowy Hydro	Hydro	14	14	14
Charlestown Square Cogeneration Plant	The GPT Group	Gas	3	0	0

5.6 Victoria

5.6.1 Existing and committed scheduled and semi-scheduled generation

Table 5-19 lists existing and committed generation in Victoria. Table 5-20 and Table 5-21 list projected scheduled and semi-scheduled generation capacities for winter and summer, respectively.

Table 5-19—Existing and committed scheduled and semi-scheduled generation - Victoria

Registered participant	Power station	Number of units and nameplate rating (MW)	Registered capacity (MW)	Plant type	Fuel
Vic Power	Anglesea[1]	1 x 150	150	Steam Turbine	Brown Coal
Aurora Energy (Tamar Valley) Pty Ltd	Bairnsdale	2 x 47	94	Gas Turbine	Natural Gas
AGL Hydro Partnership	Bogong[2] McKay Creek	2 x 80 6 x 25	140 160	Hydro	Water
AGL Hydro Partnership	Dartmouth	1 x 150	150	Hydro	Water
AGL Hydro Partnership	Eildon	2 x 60 2 x 7.5	120	Hydro	Water
Energy Brix Australia	Energy Brix	1 x 24, 2 x 33, 1 x 30, 1 x 75	195	Steam Turbine	Brown Coal
Hazelwood Power	Hazelwood	8 x 200	1,600	Steam Turbine	Brown Coal

Registered participant	Power station	Number of units and nameplate rating (MW)	Registered capacity (MW)	Plant type	Fuel
Eraring Energy	Hume (Vic)	1 x 29	29	Hydro	Water
Ecogen Energy Pty Ltd	Jeeralang A	4 x 51	204	Gas Turbine	Natural Gas
Ecogen Energy Pty Ltd	Jeeralang B	3 x 76	228	Gas Turbine	Natural Gas
Snowy Hydro Limited	Laverton North	2 x 156	312	Gas Turbine	Natural Gas
Loy Yang Marketing Management Company Pty Ltd	Loy Yang A	2 x 560 2 x 500	2,120	Steam Turbine	Brown Coal
IPM Australia Limited	Loy Yang B	2 x 500	1,000	Steam Turbine	Brown Coal
Snowy Hydro Limited	Murray 1	10 x 95	1,500	Hydro	Water
Snowy Hydro Limited	Murray 2	4 x 138		Hydro	Water
Ecogen Energy Pty Ltd	Newport	1 x 500	500	Steam Turbine	Natural Gas
AGL Hydro Partnership	Somerton	4 x 40	160	Hydro	Water
Valley Power Pty Ltd	Valley Power	6 x 50	300	Gas Turbine	Natural Gas
AGL Hydro Partnership	West Kiewa	2 x 31	62	Hydro	Water
TRUenergy Yallourn Pty Ltd	Yallourn	2 x 360, 2 x 380	1,480	Steam Turbine	Brown Coal
Committed projects					
AGL Hydro Partnership	Oaklands Hill WF	32 x 2.1	67	Wind Turbine	Wind
Origin	Mortlake	2 x 285	567	Gas Turbine	Natural Gas

1. Anglesea is a non-scheduled generator, but has been included because it is required to comply with some of the obligations of a scheduled generator
2. Bogong and Mckay Creek are scheduled as a single power station

Table 5-20—Winter aggregate scheduled and semi-scheduled generation capacities - Victoria (MW)

Power station	2011	2012	2013	157	2015	2016	2017	2018	2019	2020	Class
Anglesea [1]	155	153	159	157	155	153	159	157	155	153	NS
Bairnsdale	92	92	92	92	92	92	92	92	92	92	S
Bogong	140	140	140	140	140	140	140	140	140	140	S
Dartmouth	90	100	115	120	130	140	140	140	140	140	S
Eildon	60	60	60	60	60	60	60	60	60	60	S
Energy Brix / Morwell	164	164	164	164	164	164	164	164	164	164	S
Hazelwood	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	S
Hume (Vic) [2]	0	0	0	0	0	0	0	0	0	0	S
Jeeralang A	232	232	232	232	232	232	232	232	232	232	S
Jeeralang B	255	255	255	255	255	255	255	255	255	255	S
Laverton North	340	340	340	340	340	340	340	340	340	340	S
Loy Yang A	2,270	2,270	2,270	2,270	2,270	2,270	2,270	2,270	2,270	2,270	S
Loy Yang B	1,050	1,050	1,050	1,050	1,050	1,050	1,050	1,050	1,050	1,050	S
Mckay Creek	160	160	160	160	160	160	160	160	160	160	S

Power station	2011	2012	2013	157	2015	2016	2017	2018	2019	2020	Class
Murray 1	950	950	855	855	855	950	950	950	950	950	S
Murray 2	578	578	578	578	578	433	578	578	578	578	S
Newport	510	510	510	510	510	510	510	510	510	510	S
Somerton	163	161	161	161	161	161	161	161	161	161	S
Valley Power	336	336	336	336	336	315	315	315	315	315	S
West Kiewa	52	72	72	72	72	72	72	72	72	72	S
Yallourn	1,487	1,487	1,487	1,487	1,487	1,487	1,487	1,487	1,487	1,487	S
Committed projects											
Mortlake	553	553	553	553	553	553	553	553	553	553	S
Oaklands Hill WF	67	67	67	67	67	67	67	67	67	67	SS
Total	**11,304**	**11,330**	**11,256**	**11,259**	**11,267**	**11,204**	**11,355**	**11,353**	**11,351**	**11,349**	

1. Anglesea is a non-scheduled generator, but has been included because it is required to comply with some of the obligations of a scheduled generator
2. Hume has two units located near the Vic-NSW border. One unit is represented as being in Victoria, the other in New South Wales. Output can be dispatched to either New South Wales or Victoria or both

Table 5-21—Summer aggregate scheduled and semi-scheduled generation capacities - Victoria (MW)

Power station	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	Class
Anglesea[1]	156	154	152	158	156	154	152	158	156	154	NS
Bairnsdale	68	68	68	68	68	68	68	68	68	68	S
Bogong	140	140	140	140	140	140	140	140	140	140	S
Dartmouth	90	100	115	120	130	140	140	140	140	140	S
Eildon	92	92	92	92	92	92	92	92	92	92	S
Energy Brix/ Morwell	164	164	164	164	164	164	164	164	164	164	S
Hazelwood	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	S
Hume (VIC)[2]	11	12	29	29	29	29	29	29	29	29	S
Jeeralang A	200	200	200	200	200	200	200	200	200	200	S
Jeeralang B	216	216	216	216	216	216	216	216	216	216	S
Laverton North	300	300	300	300	300	300	300	300	300	300	S
Loy Yang A	2,170	2,190	2,190	2,190	2,190	2,190	2,190	2,190	2,190	2,190	S
Loy Yang B	965	965	965	965	965	965	965	965	965	965	S
Mckay Creek	160	160	160	160	160	160	160	160	160	160	S
Murray 1	950	950	855	855	855	855	950	950	950	950	S
Murray 2	578	578	578	578	578	578	578	578	578	578	S
Newport	475	475	475	475	475	475	475	475	475	475	S
Somerton	132	134	133	133	133	133	133	133	133	133	S
Valley Power	270	270	270	270	270	270	270	270	270	270	S
West Kiewa	66	66	66	66	66	66	66	66	66	66	S
Yallourn	1,420	1,420	1,420	1,420	1,420	1,420	1,420	1,420	1,420	1,420	S

Power station	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	Class
Committed projects											
Mortlake	518[3]	518	518	518	518	518	518	518	518	518	S
Oaklands Hill WF	0	42	42	42	42	42	42	42	42	42	SS
Total	**10,741**	**10,814**	**10,748**	**10,759**	**10,767**	**10,775**	**10,868**	**10,874**	**10,872**	**10,870**	

1. Anglesea is a non-scheduled generator, but has been included because it is required to comply with some of the obligations of a scheduled generator
2. Hume has two units located near the Vic-NSW border. One unit is represented as being in Victoria, the other in New South Wales. Output can be dispatched to either New South Wales or Victoria or both
3. Mortlake is expected to commence commissioning in the fourth quarter of 2010

5.6.2 Changes since the 2009 ESOO (existing generation)

AGL Energy advises the following:

- Dartmouth Power Station revised its capacity based on an updated profile of water storage recovery over time.
- Eildon Power Station revised its capacity from 120 MW to 60 MW during winter and from 120 MW to 92 MW during summer to reflect an updated water storage recovery profile.
- West Kiewa Power Station revised its capacity from 72 MW to 52 MW during winter 2011 due to changes in the maintenance schedule.

Eraring Energy advises that Hume Power Station has a capacity of 29 MW, but its output depends on the available water head and irrigation water release requirements, resulting in projected capacities of 11 MW during summer 2010/11, 12 MW during summer 2011/12, and 29 MW from 2012/13 onwards to reflect these limitations.

International Power advises that Hazelwood Power Station revised its capacity from 1,580 MW to 1,600 MW during summer due to an output re-evaluation.

Loy Yang Marketing Management Company advises that Loy Yang A Power Station revised its capacity from 2,190 MW to 2,170 MW during summer 2010/11 due to a change in timing of a Unit 2 upgrade.

Snowy Hydro advises the following:

- Laverton North Power Station revised its capacity during summer from 310 MW to 300 MW after analysing power output with respect to ambient temperature. The capacity during winter 2014 and 2015 has been revised from 170 MW to 340 MW due to a change in the maintenance schedule.
- Murray 1 Power Station revised its maintenance schedule for works on individual units, which resulted in variations in capacity until winter 2016.
- Murray 2 Power Station revised its capacity during both summer and winter from 550 MW to 578 MW due to an output re-evaluation projecting increased capacities for Units 1, 2 and 4. The maintenance schedule has also been revised, with Unit 2 now planned for maintenance in winter 2016.

5.6.3 Committed project developments

AGL Energy advises that Oaklands Hill Wind Farm is now a committed project (reported as a publicly announced proposal in the 2009 ESOO), and will operate as semi-scheduled generation. Comprising 32 turbines, the new wind farm will have a total capacity of 67 MW during winter. At temperatures above 40°C, each turbine is limited to an output of 1.3 MW, limiting the total capacity to 42 MW during summer (Victoria's summer reference temperature is 41°C). The wind farm is expected to be commissioned by August 2011.

Loy Yang Marketing Management Company advises that the Loy Yang A Power Station Unit 2 upgrade is a committed project. The upgrade will increase the unit's capacity by 10 MW during winter and by 20 MW during summer, and is expected to be completed by June 2011.

Origin Energy advises that Stage 1 of Mortlake Power Station is a committed project. The power station is planned to be developed in two stages. Comprising two units, Stage 1 will have a total capacity of 553 MW during winter and 518 MW during summer. The combined cycle gas-fired power station will operate as scheduled generation, and is expected to commence commissioning in the fourth quarter of 2010 (consistent with the 2009 ESOO).

AEMO is not aware of any non-scheduled generation projects in Victoria that are currently classified as committed according to AEMO's commitment criteria.

5.6.4 Plant limitations

The capacity of some plants may be restricted depending on water availability for generation or cooling.

Energy Brix Australia advises that Energy Brix/Morwell Power Station Unit 1 (MOR1, 72 MW available scheduled capacity) is limited to 50 MW if Unit 2 (MOR2, 26 MW available scheduled capacity) is operating.

Eraring Energy advises that Hume Power Station is expected to be unavailable in winter. Generation in summer is affected by water releases for irrigation purposes, which are controlled by the Murray Darling Basin Commission. Hume Power Station has two units that may be dispatched to either New South Wales or Victoria. AEMO has reported the power station's data as if one unit was a generator in New South Wales and the other a generator in Victoria.

International Power advises the following:

- Loy Yang B Power Station depends on water supplies from Blue Rock, Moondarra, Narracan, and Yallourn Weir, and coal supplies from the Loy Yang open cut mine.
- Hazelwood Power Station might have a restricted capacity due to a limit of 14GL of water per year from Moondarra reservoir (one of its cooling water sources).

Snowy Hydro advises that there are conditions to its EPA licence for Laverton North Power Station. Snowy Hydro must submit a report if the power station operates at a capacity factor greater than 10%:

- averaged over a 12-month reporting period, or
- in any period during which AEMO has published a notice (or notices) declaring a Lack of Reserve (LOR) condition in Victoria.

The report must investigate the feasibility of converting the current open cycle gas turbine (OCGT) plant to a combined cycle gas turbine (CCGT) and other opportunities to reduce emissions

Vic Power advises that Anglesea Power Station generation is restricted when the station plume sulphur content exceeds Environmental Protection Authority (EPA) tolerance levels of 300 parts per billion (ppb).

5.6.5 Plant retirements

AEMO has not been advised of any planned plant retirements in Victoria.

5.6.6 Historical generation levels and performance

Table 5-22 lists historical Victorian scheduled generation output from 2005/06-2009/10. Figures for 2009/10 are calculated on a pro-rata basis from May 2010.

Table 5-23: Historical scheduled and semi-scheduled generation (GWh) - Victoria[1]

Power station	2005/06	2006/07	2007/08	2008/09	2009/10 pro-rata
Anglesea[2]	1,358	1,296	1,323	1,194	1,333
Bairnsdale	65	280	240	198	62
Bogong and McKay	103	48	86	69	166
Dartmouth	39	407	0	0	0
Eildon	123	45	57	49	55
Energy Brix Complex	1,067	1,085	1,185	1,227	1,267
Hazelwood	11,337	11,865	11,362	12,194	11,577
Hume	41	20	27	27	19
Jeeralang A	18	13	53	64	15
Jeeralang B	32	42	127	230	75
Laverton North	0	445	203	133	235
Loy Yang A	17,111	17,009	17,269	16,696	17,432
Loy Yang B	8,796	8,314	8,947	8,615	8,734
Murray 1	2,251	1,887	1,306	1,650	1,904
Newport	437	1294	1747	1095	696
Somerton	15	140	118	105	83
Valley Power Peaking Facility	14	381	193	140	62
West Kiewa	153	61	114	109	173
Yallourn W	11,301	10,734	10,300	12,014	11,350
Total	**54,261**	**55,366**	**54,657**	**55,809**	**55,238**

1. There is no semi-scheduled generation in Victoria
2. Anglesea is a non-scheduled generator, but is required to comply with some of the obligations of a scheduled generator

5.6.7 Advanced and publicly announced proposals

AEMO sought information from generators and project proponents about the status of generation projects under development. Some companies provide AEMO with information that is commercial in confidence. Where this occurs, AEMO publishes as much publicly available information as possible.

Table 5-24 lists information about proposed generation projects in Victoria.

More detailed information about advanced proposals includes the following:

- **AGL Energy** advises that Macarthur Wind Farm is now an advanced proposal, and is expected to operate as semi-scheduled generation. Comprising 174 turbines with a total capacity of 365 MW, it is expected to be commissioned by April 2013. The 2009 ESOO reported this as a publicly announced proposal.
- **Origin Energy** advises that Stage 2 of Mortlake Power Station is an advanced proposal. This project is expected to add another 450 MW to Stage 1 of the combined-cycle gas-fired power station. No firm commissioning date has been set. The 2009 ESOO also reported Stage 2 as an advanced proposal.

See Section 5.6.3 for information about committed project developments.

Table 5-24–Advanced and publicly announced proposals - Victoria

Company/operator	Project	Fuel/ technology	Capacity (MW)	Commissioning date	Site	Major Components	Planning consents / construction approval / EIS	Finance	Firm construct date set	Status	Class
Acciona Energy	Berrimal WF	Wind Turbine	24	Q1, 2013	✓	-	✓	-	-	Pub An	SS
Acciona Energy	Mortlake WF	Wind Turbine	144	Q3, 2013	✓	-	-	-	-	Pub An	SS
Acciona Energy	Mt Gellibrand WF	Wind Turbine	172.5	Q4, 2012	✓	-	✓	-	-	Pub An	SS
Acciona Energy	Newfield WF	Wind Turbine	22.5	Q1, 2013	✓	-	✓	-	-	Pub An	SS
Acciona Energy	Waubra North WF	Wind Turbine	45	Q3, 2014	✓	-	-	-	-	Pub An	SS
AGL Energy	Macarthur WF	Wind Turbine	365	Q2, 2013	✓	-	✓	✓	-	Adv	SS
AGL Energy	Tarrone	Gas/ OCGT	1160	Q4, 2012	✓	-	-	✓	-	Pub An	S
HRL Developments	Dual Gas Demonstration Project	Brown Coal/ IDGCC	550	2013	✓	-	-	-	-	Pub An	S
International Power	Winchelsea WF	Wind Turbine	28	TBA	-	-	-	-	-	Pub An	SS
Meridian Energy	Mt Mercer WF	Wind Turbine	130-150	2012	✓	-	✓	-	-	Pub An	SS
Mitsui and Co.	Bald Hills WF	Wind Turbine	104	Q2, 2012	✓	-	-	-	-	Pub An	SS
Origin Energy	Lexton WF	Wind Turbine	38	TBA	✓	-	y	-	-	Pub An	SS
Origin Energy	Mortlake Stage 2	Gas/ CCGT	450	TBA	✓	-	✓	✓	-	Adv	S
Origin Energy	Stockyard WF	Wind Turbine	484	TBA	✓	-	-	-	-	Pub An	SS
Pacific Hydro	Crowlands WF	Wind Turbine	144	TBA	-	-	-	-	-	Pub An	SS

Company/operator	Project	Fuel/ technology	Capacity (MW)	Commissioning date	Site	Major Components	Planning consents / construction approval / EIS	Finance	Firm construct date set	Status	Class
RES	Ararat WF	Wind Turbine	247.5	Q2, 2013	✓	-	-	-	-	Pub An	SS
Roaring 40s	Sidonia Hills WF	Wind Turbine	68	2016	-	-	-	-	-	Pub An	SS
Santos	Shaw River	Gas/ CCGT	500	Q4, 2012	✓	-	-	-	-	Pub An	S
Transfield Services	Baynton WF	Wind Turbine	130	Q4, 2015	-	-	-	-	-	Pub An	SS
Transfield Services	Ben More WF	Wind Turbine	90	Q4, 2014	-	-	-	-	-	Pub An	SS
TRUenergy	Yallourn CCGT	Gas/ CCGT	500	TBA	✓	-	-	-	-	Pub An	S
Union Fenosa	Berrybank WF	Wind Turbine	180-250	Q1, 2014	✓	-	-	-	-	Pub An	SS
Union Fenosa	Darlington WF	Wind Turbine	270-594	Q1, 2015	✓	-	-	-	-	Pub An	SS
Union Fenosa	Hawkesdale WF	Wind Turbine	62-77	Q1, 2014	✓	-	✓	-	-	Pub An	SS
Union Fenosa	Ryan Corner WF	Wind Turbine	136-170	Q1, 2014	✓	-	✓	-	-	Pub An	SS
Union Fenosa	Tarrone WF	Wind Turbine	34-66	Q1, 2015	✓	-	-	-	-	Pub An	SS
West Wind	Lal Lal WF - Stage 1	Wind Turbine	Approx 90 (131MW for both stages)	2013	✓	-	-	-	-	Pub An	SS
West Wind	Lal Lal WF - Stage 2	Wind Turbine	Approx 40[1]	2014	✓	-	-	-	-	Pub An	SS
West Wind	Moorabool WF - Stage 1	Wind Turbine	150	2014	✓	-	-	-	-	Pub An	SS

Company/operator	Project	Fuel/ technology	Capacity (MW)	Commissioning date	Site	Major Components	Planning consents / construction approval / EIS	Finance	Firm construct date set	Status	Class
West Wind	Moorabool WF - Stage 2	Wind Turbine	180	2015	✓	-	-	-	-	Pub An	SS
Wind Farm Developments	Drysdale WF	Wind Turbine	26	2012	✓	-	✓	-	-	Pub An	SS
Wind Farm Developments	Naroghid WF	Wind Turbine	42	2012	✓	-	✓	-	-	Pub An	SS
Wind Farm Developments	The Sisters WF	Wind Turbine	24	2012	✓	-	✓	-	-	Pub An	SS
Wind Farm Developments	Woolsthorpe WF	Wind Turbine	40	2012	✓	-	✓	-	-	Pub An	SS
NewEn Australia	Morton's Lane	Wind Turbine	20	Q3, 2012	✓	-	-	-	-	Pub An	NS
Pacific Hydro	Portland Wind Farm (Stage 4)	Wind Turbine	Up to 54	Q4, 2011	✓	-	-	-	-	Pub An	NS

1. Lal Lal Wind Farm Stage 1 and Stage 2 combined will have a nominal capacity of 131 MW

5.6.8 Non-scheduled generation

Table 5-25 lists information about non-scheduled generation in Victoria. AEMO is not aware of any committed non-scheduled generation projects.

Table 5-25—Existing non-scheduled generation - Victoria

Power station	Survey respondent	Fuel/ technology	Capacity (MW)	Anticipated capacity for winter MD (MW)	Anticipated capacity for summer MD (MW)
Waubra Wind Farm	Acciona Energy	Wind	192	192	192
Banimboola Power Station	AGL Energy	Hydro	13	0	1
Brooklyn Landfill	AGL Energy	Thermal - Landfill Gas	3	1	1
Clover Power Station	AGL Energy	Hydro	30	29	23
Rubicon Mountain Streams Station	AGL Energy	Hydro	14	9	1
Yarrawonga Hydro Power Station	AGL Energy	Hydro	10	0	5
Wonthaggi Wind Farm	Country Energy	Wind	12	3	3
Shepparton Wastewater Treatment Facility	Diamond Energy	Methane Gas	1	1	1
Tatura Biomass Generator	Diamond Energy	Biomass	1	1	1
Berwick Power Plant	EDL	Reciprocating - Gas	7	5	5
Broadmeadows Power Plant	EDL	Reciprocating - Gas	7	6	6
Clayton Power Plant	EDL	Reciprocating - Gas	11	11	9
Springvale Power Plant	EDL	Thermal – Landfill Gas	4	2	2
Mornington Waste Disposal Facility	Energy Australia	Thermal - Landfill Gas	1	1	1
Wyndham Waste Disposal Facility	Energy Australia	Thermal - Landfill Gas	1	1	1
Ballarat Base Hospital	Energy Response	Gas	2	2	1
Symex, Port Melbourne Plant	Energy Response	Gas	5	5	5
Hallam Road	LMS Generation	Thermal - Landfill Gas	3	3	3
Wollert	LMS Generation	Thermal - Landfill Gas	4	4	4
Challicum Hills Wind Farm	Pacific Hydro	Wind	53	53	53
Codrington Wind Farm	Pacific Hydro	Wind	18	18	18
Portland Wind Farm	Pacific Hydro	Wind	164	102	102
Yambuk Wind Farm	Pacific Hydro	Wind	30	30	30
Glenmaggie	Pacific Hydro	Hydro	4	0	0
Eildon	Pacific Hydro	Hydro	5	0	0
William Hovel	Pacific Hydro	Hydro	2	0	0
Toora Wind Farm	Transfield Services	Wind	21	7	7
Longford Plant	TRUenergy	Gas	31	31	31

Power station	Survey respondent	Fuel/ technology	Capacity (MW)	Anticipated capacity for winter MD (MW)	Anticipated capacity for summer MD (MW)
Anglesea[1]	Vic Power	Brown coal	150	155	156

1. Anglesea is a non-scheduled generator, but is required to comply with some of the obligations of a scheduled generator

5.7 South Australia

5.7.1 Existing and committed scheduled and semi-scheduled generation

Table 5-26 lists existing and committed generation in South Australia. Table 5-27 and Table 5-28 list projected scheduled and semi-scheduled generation capacities for South Australia for winter and summer, respectively.

Table 5-26—Existing and committed scheduled and semi-scheduled generation - South Australia

Registered participant	Power station	Number of units and nameplate rating (MW)	Registered capacity (MW)	Plant type	Fuel
AGL Energy	Torrens Island A	4 x 120	480	Conventional Steam	Natural Gas
AGL Energy	Torrens Island B	4 x 200	800	Conventional Steam	Natural Gas / Oil
Infratil	Angaston	30 x 1.67	50	Reciprocating Diesel	Distillate
International Power	Dry Creek	3 x 52	156	Gas Turbine	Natural Gas
International Power	Mintaro	1 x 90	90	Gas Turbine	Natural Gas
International Power	Pelican Point[1]	1 x 487	487	Combined	Natural Gas
International Power	Port Lincoln	2 x 24	48	Gas Turbine	Distillate
International Power	Snuggery	3 x 26	78	Gas Turbine	Distillate
Origin Energy	Ladbroke Grove	2 x 46	92	Gas Turbine	Natural Gas
Flinders Operating Services	Northern	2 x 260	520	Conventional Steam	Coal
Flinders Operating Services	Osborne	1 x 180	180	Cogeneration	Natural Gas
Flinders Operating Services	Playford	4 x 60	240	Conventional Steam	Coal
Origin Energy	Quarantine	4 x 25 1 x 128	227	Gas Turbine	Natural Gas
TRUenergy	Hallett	11 units	192	Gas Turbine	Natural Gas / Distillate
AGL Energy	Hallett Stage 1- Brown Hill	45 x 2.1	94.5	Wind Turbine	Wind
AGL Energy	Hallett Stage 2- Hallett Hill	34 x 2.1	71.4	Wind Turbine	Wind
Pacific Hydro	Clements Gap	27 x 2.1	56.7	Wind Turbine	Wind
Infigen Energy	Lake Bonney Stage 2	53 x 3	159	Wind Turbine	Wind

Registered participant	Power station	Number of units and nameplate rating (MW)	Registered capacity (MW)	Plant type	Fuel
TrustPower Ltd	Snowtown Stage 1	47 x 2.1	98.7	Wind Turbine	Wind
		Committed projects			
TruEnergy	Hallet GT 2-3	1 x 23	23	OCGT	Natural Gas
AGL Energy	Hallett 4 (North Brown Hill) WF	63 x 2.1	132	Wind Turbine	Wind
AGL Energy	Hallett 5 (The Bluff) WF	25 x 2.1	53	Wind Turbine	Wind
Lake Bonney Wind Power Pty Ltd	Lake Bonney S3 WF[2]	13 x 3	39	Wind Turbine	Wind
International Power	Port Lincoln[3]	1 x 23	23	Gas Turbine	Distillate
Roaring 40s	Waterloo WF	37 x 3	111	Wind Turbine	Wind

1. Pelican Point Power Station is a CCGT. It comprises two gas turbines and heat recovery steam generators and a single steam turbine. With the level of redundancy in its systems, it is considered to be 2 units of approximately 245 MW each
2. Lake Bonney Stage 3 is a committed project currently under construction
3. Port Lincoln's capacity includes two existing units. This represents a third 25 MW gas-fuelled turbine, with an expected completion date of December 2010

Table 5-27—Winter aggregate scheduled and semi-scheduled generation - South Australia (MW)

Power station	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Class
Angaston	49	49	49	49	49	49	49	49	49	49	S
Clements Gap	57	57	57	57	57	57	57	57	57	57	SS
Dry Creek	146	146	147	148	148	148	148	148	148	148	S
Hallett 1 (Brown Hill) WF	95	95	95	95	95	95	95	95	95	95	SS
Hallett 2 (Hallett Hill) WF	71	71	71	71	71	71	71	71	71	71	SS
Hallett GT[1]	203	203	203	203	203	203	203	203	203	203	S
Ladbroke Grove	86	86	86	86	86	86	86	86	86	86	S
Lake Bonney S2 WF	159	159	159	159	159	159	159	159	159	159	S
Mintaro GT	90	90	90	90	90	90	90	90	90	90	S
Northern	546	546	546	546	546	546	546	546	546	546	S
Osborne	192	192	192	192	192	192	192	192	192	192	S
Pelican Point	474	474	474	474	474	474	474	474	474	474	S
Playford	240	240	240	240	240	240	240	240	240	240	S
Port Lincoln[2]	73	73	73	73	73	73	73	73	73	73	S
Quarantine	223	223	223	223	223	223	223	223	223	223	S
Snowtown WF	99	99	99	99	99	99	99	99	99	99	S
Snuggery	66	66	66	66	66	66	66	66	66	66	S
Torrens Island A	504	504	504	504	504	504	504	504	504	504	S
Torrens Island B	820	820	820	820	820	820	820	820	820	820	S
					Committed projects						
Hallett 4 (North Brown Hill) WF	132	132	132	132	132	132	132	132	132	132	SS

Power station	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Class
Hallett 5 (The Bluff) WF	0	53	53	53	53	53	53	53	53	53	SS
Lake Bonney S3 WF[3]	39	39	39	39	39	39	39	39	39	39	SS
Waterloo WF	111	111	111	111	111	111	111	111	111	111	SS
Total	**4,475**	**4,528**	**4,529**	**4,530**	**4,530**	**4,530**	**4,530**	**4,530**	**4,530**	**4,530**	

1. The Hallett GT capacity includes 11 existing units and a committed project for a 12th gas-fuelled unit
2. Port Lincoln's capacity includes two existing units and a committed project for a third 25 MW gas-fuelled turbine, with an expected completion date of December 2010
3. Lake Bonney Stage 3 is a committed project currently under construction

Table 5-28—Summer aggregate scheduled and semi-scheduled generation - South Australia (MW)

Power station	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	Class
Angaston	49	49	49	49	49	49	49	49	49	49	S
Clements Gap WF	57	57	57	57	57	57	57	57	57	57	SS
Dry Creek	115	115	116	117	118	118	118	118	118	118	S
Hallett 1 (Brown Hill) WF 2	59	59	59	59	59	59	59	59	59	59	SS
Hallett 2 (Hallett Hill) WF 2	44	44	44	44	44	44	44	44	44	44	SS
Hallett GT[1]	176	199	199	199	199	199	199	199	199	199	S
Ladbroke Grove	70	70	70	70	70	70	70	70	70	70	S
Lake Bonney S2 WF	159	159	159	159	159	159	159	159	159	159	S
Mintaro GT	67	68	68	68	68	68	68	68	68	68	S
Northern	542	542	542	542	542	542	542	542	542	542	S
Osborne	175	175	175	175	175	175	175	175	175	175	S
Pelican Point	448	448	448	448	448	448	448	448	448	448	S
Playford	200	240	240	240	240	240	240	240	240	240	S
Port Lincoln[2]	57	57	57	57	57	57	57	57	57	57	S
Quarantine	191	191	191	191	191	191	191	191	191	191	S
Snowtown WF	99	99	99	99	99	99	99	99	99	99	S
Snuggery	51	51	51	51	51	51	51	51	51	51	S
Torrens Island A	480	480	480	480	480	480	480	480	480	480	S
Torrens Island B	800	800	800	800	800	800	800	800	800	800	S
Committed projects											
Hallett 4 (North Brown Hill) WF	0	82	82	82	82	82	82	82	82	82	SS
Hallet 5 (The Bluff) WF	0	33	33	33	33	33	33	33	33	33	SS
Lake Bonney S3 WF [3]	39	39	39	39	39	39	39	39	39	39	SS
Waterloo WF	111	111	111	111	111	111	111	111	111	111	SS
Total	**3,989**	**4,168**	**4,169**	**4,170**	**4,171**	**4,171**	**4,171**	**4,171**	**4,171**	**4,171**	

Power station	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	Class

1. The Hallett GT capacity includes 11 existing units and a committed project for a 12th gas-fuelled unit
2. Port Lincoln's capacity includes two existing units and a committed project for a third 25 MW gas-fuelled turbine, with an expected completion date of December 2010
3. Lake Bonney Stage 3 is a committed project currently under construction

5.7.2 Changes since the 2009 ESOO (existing generation)

TruEnergy advises that Hallett GT enhanced its capacity during summer with the installation of fogging capability on the existing units in 2009. Improved information has also led to a minor degradation in winter capacity of 8 MW. A new unit is expected to be commissioned by January 2011, which will add 23 MW during both summer and winter.

AGL Energy advises that Hallett Stage 2 (Hallett Hill) Wind Farm has decreased the summer capacities published in 2009 by approximately 27 MW to account for limited output from the turbines at high temperatures.

5.7.3 Committed project developments

AGL Energy advises that it plans to continue with its wind farm developments in the Hallett area in stages. Hallett 4, located at North Brown Hill, is currently under construction and is expected to be completed around May 2011.

AGL has also entered into agreements for the construction of the 52.5 MW Hallett 5 wind farm at the Bluff Range in the mid-north of South Australia. Construction is expected to begin in July with completion anticipated in December 2011.

Infigen Energy advises that it is developing a third stage at Lake Bonney in the State's South East. Substantial construction is complete, and commissioning is expected to be complete by the end of July 2010.

International Power advises that a third distillate-fired open-cycle gas turbine is currently under construction adjacent to the existing International Power Port Lincoln generation facilities. This additional unit should be complete by mid-2010, and will increase the nameplate capacity at that installation to 71 MW.

Roaring 40s has commenced construction of its 111 MW Waterloo Wind Farm located near the Clare Valley in South Australia, approximately 30 km south-east of the township of Clare. Roaring 40s has entered into long-term contracts with Vestas to supply and maintain 37 x 3 MW, V90 turbines, and with CLP (through its subsidiary TRUenergy) and Hydro Tasmania to purchase renewable energy certificates and hedge electricity prices for the first 10 years of production.

TRUenergy advises that it commenced work at Hallett Power Station with the addition of a new 23 MW gas turbine. The project is expected to be operational from January 2011.

Infratil energy advises that Point Stanvac A and B will be non-scheduled, diesel-fired plants, and are expected to be commissioned in the fourth quarter of 2010.

5.7.4 Plant limitations

The capacity of some plants may be restricted depending on water availability for generation or cooling.

AGL Energy advises that the Hallett Wind Farm turbines are limited to 1.3 MW at temperatures above 40°C.

Alinta Energy advises that Playford Power Station is currently not able to operate at its full registered capacity, and the expected restoration to 240 MW will require further plant investment.

5.7.5 Plant retirements

AEMO has not been advised of any planned plant retirements in South Australia.

5.7.6 Historical generation levels and performance

Table 5-29 lists historical South Australian scheduled and semi-scheduled generation output from 2005/06-2009/10. Figures for 2009/10 are calculated on a pro-rata basis from May 2010.

Table 5-29 - Historical scheduled and semi-scheduled generation (GWh) - South Australia

Power station	2005/06	2006/07	2007/08	2008/09	2009/10 pro-rata
Angaston	2	4	2	2	0
Clements Gap WF	0	0	0	3	172
Dry Creek GT	1	16	10	6	11
Hallett GT	22	151	28	23	32
Hallett 1 WF	0	0	91	327	347
Hallett 2 WF	0	0	0	16	257
Ladbroke Grove	348	249	141	192	185
Lake Bonney Stage 2 WF	0	3	230	342	296
Mintaro GT	1	36	8	4	9
Northern	3,997	4,466	4,013	4,213	3,670
Osborne	1,176	1,251	1,230	1,244	1,167
Pelican Point	1,620	2,775	3,281	3,281	2,892
Playford B	541	722	870	695	1,000
Port Lincoln GT	1	1	2	2	2
Quarantine	128	80	84	97	271
Snowtown WF	0	0	11	320	376
Snuggery	0	1	2	2	3
Torrens Island A	396	376	527	538	312
Torrens Island B	2,141	2,350	2,782	1,976	1,714
Total	**10,374**	**12,481**	**13,312**	**13,283**	**12,716**

5.7.7 Advanced and publicly announced proposals

AEMO sought information from generators and project proponents about the status of generation projects under development. Some companies provide AEMO with information that is commercial in confidence. Where this occurs, AEMO publishes as much publicly available information as possible.

Table 5-30 lists information about proposed generation projects in South Australia.

More detailed information about advanced proposals includes the following:

- **Origin Energy** advises that Quarantine Power Station Unit 6 is an advanced proposal. The new gas-fuelled turbine is expected to operate as scheduled generation. There is no firm commissioning date as yet.
- **TrustPower** advises that the Snowtown Wind Farm is an advanced proposal. The new wind farm is expected to operate as semi-scheduled generation, and has a planned commissioning date in 2011.

See Section 5.7.3 for information about committed project developments.

Table 5-30—Advanced and publicly announced proposals - South Australia

Company/operator	Project	Fuel/ technology	Capacity (MW)	Commissioning date	Site	Major comp'ts	Planning consents/ construction approval/ EIS	Finance	Firm construct date Set	Status	Class
Acciona Energy	Allendale WF	Wind Turbine	69	Q1, 2013	✓	-	-	-	-	Pub An	SS
AGL Energy	Barn Hill WF	Wind Turbine	124-186	TBA	✓	-	✓	-	-	Pub An	SS
AGL Energy	Hallett (Mt Bryan) WF	Wind Turbine	80	Q3, 2014	✓	-	-	✓	-	Pub An	SS
AGL Energy	Torrens Island C	Gas/ OCGT	400-700	TBA	✓	-	-	✓	-	Pub An	S
Altona Energy	Arckaringa	Syngas/ IGCC	570	2015	-	-	-	-	-	Pub An	S
Geodynamics	Innamincka	Geothermal	550	2016-2018	-	-	-	-	-	Pub An	S
Infigen	Woakwine WF	Wind Turbine	300-600	TBA	✓	-	-	-	-	Pub An	SS
International Power	Pelican Point S2	Gas/ CCGT	300	TBA	✓	-	-	-	-	Pub An	S
International Power	Willogoleche WF	Wind Turbine	50	TBA	-	-	-	-	-	Pub An	SS
National Power	Lincoln Gap WF	Wind Turbine	177	Q4, 2011	✓	-	-	-	-	Pub An	SS
Origin Energy	Collaby WF	Wind Turbine	150	TBA	✓	-	-	-	-	Pub An	SS
Origin Energy	Quarantine	Gas	125	TBA	✓	-	✓	✓	-	Adv	S
Pacific Hydro	Carmody's Hill	Wind Turbine	140	TBA	-	-	-	-	-	Pub An	SS
Pacific Hydro	Keyneton	Wind Turbine	120	TBA	-	-	-	-	-	Pub An	SS
Pacific Hydro	Vincent North WF	Wind Turbine	60	TBA	-	-	-	-	-	Pub An	SS
Roaring 40s	Robertstown WF	Wind Turbine	90	2012	-	-	-	-	-	Pub An	SS
Roaring 40s	Stony Gap WF	Wind Turbine	99	2014	-	-	-	-	-	Pub An	SS
Transfield Services	Kongorong WF	Wind Turbine	120	Q4, 2017	-	-	-	-	-	Pub An	SS
Transfield Services	Kulpara WF	Wind Turbine	109	Q4, 2018	-	-	-	-	-	Pub An	SS
Transfield Services	Mount Hill WF	Wind Turbine	80	Q4, 2019	-	-	-	-	-	Pub An	SS
TrustPower	Snowtown S2 WF	Wind Turbine	206	2011	✓	-	✓	✓	-	Adv	SS

5.7.8 Non-scheduled generation

Table 5-31 lists information about non-scheduled generation in South Australia.

Table 5-31—Existing and committed non-scheduled generation - South Australia

Power station	Survey respondent	Fuel/ technology	Capacity (MW)	Anticipated capacity for winter MD (MW)	Anticipated capacity for summer MD (MW)
Wattle Point	AGL Energy	Wind	91	91	83
Canunda	Canunda Power	Wind	66	66	66
Pedler Creek	EDL	Landfill Gas	3	3	3
Wingfield I & II	EDL	Landfill Gas	8	4	4
Amcor Gawler Glass Bottle Plant	Energy Response	Diesel	4	3	3
Terminal Storage Mini Hydro	Hydro Tasmania	Hydro	3	1	1
Lake Bonney Stage 1 Wind Farm	Infigen Energy	Wind	81	81	0
Lonsdale Power Station	Infratil Energy	Diesel	20	20	20
Cathedral Rocks Wind Farm	Roaring 40s	Wind	66	60	66
Mt Millar Wind Farm	Transfield Services	Wind	70	25	25
Starfish Hill Wind Farm	Transfield Services	Wind	35	11	11
Committed non-scheduled generation					
Pt Stanvac A	Infratil Energy	Diesel	29	29	29
Pt Stanvac B	Infratil Energy	Diesel	29	29	29

5.8 Tasmania

5.8.1 Existing and committed scheduled and semi-scheduled generation

Table 5-32 lists existing and committed generation in Tasmania. Table 5-33 and Table 5-34 list projected scheduled and semi-scheduled generation capacities for Tasmania for winter and summer, respectively.

Table 5-32—Existing and committed scheduled and semi-scheduled generation - Tasmania

Registered participant	Power station	Number of units and nameplate rating (MW)	Registered capacity (MW)	Plant type	Fuel
Hydro-Electric Corporation	Bastyan	1 x 79.9	79.9	Hydro	Water
Aurora Energy (Tamar Valley) Pty Ltd	Bell Bay Three Power Station	3 x 35	105	Gas Turbine	Natural Gas
Hydro-Electric Corporation	Catagunya	2 x 24	48	Hydro	Water
Hydro-Electric Corporation	Cethana	1 x 85	85	Hydro	Water
Hydro-Electric Corporation	Devils Gate	1 x 60	60	Hydro	Water
Hydro-Electric Corporation	Fisher	1 x 43.2	43.2	Hydro	Water
Hydro-Electric Corporation	Gordon	3 x 144	432	Hydro	Water
Hydro-Electric Corporation	John Butters	1 x 144	144	Hydro	Water
Hydro-Electric Corporation	Lake Echo	1 x 32.4	32.4	Hydro	Water
Hydro-Electric Corporation	Lemonthyme	1 x 51	51	Hydro	Water
Hydro-Electric Corporation	Liapootah	3 x 27.9	83.7	Hydro	Water
Hydro-Electric Corporation	Mackintosh	1 x 79.9	79.9	Hydro	Water
Hydro-Electric Corporation	Meadowbank	1 x 40	40	Hydro	Water
Hydro-Electric Corporation	Poatina	6 x 50	300	Hydro	Water
Hydro-Electric Corporation	Reece	2 x 115.6	231.2	Hydro	Water
Aurora Energy (Tamar Valley) Pty Ltd	Tamar Valley Combined Cycle Power Station	1 x 141 (GT) 1 x 68 (ST)	208	Combined Cycle (CCGT)	Natural Gas
Aurora Energy (Tamar Valley) Pty Ltd	Tamar Valley Peaking Power Station	1 x 58	58	Gas Turbine	Natural Gas
Hydro-Electric Corporation	Tarraleah	6 x 15	90	Hydro	Water
Hydro-Electric Corporation	Trevallyn	4 x 20	80	Hydro	Water
Hydro-Electric Corporation	Tribute	1 x 82.8	82.8	Hydro	Water
Hydro-Electric Corporation	Tungatinah	5 x 25	125	Hydro	Water
Hydro-Electric Corporation	Wayatinah	3 x 12.8	38.4	Hydro	Water
Hydro-Electric Corporation	Wilmot	1 x 30.6	30.6	Hydro	Water

Table 5-33—Winter aggregate scheduled and semi-scheduled generation capacities - Tasmania (MW)

Power station	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Class
Bastyan	80	80	80	80	80	80	80	80	80	80	S
Bell Bay Three	120	120	120	120	120	120	120	120	120	120	S
Catagunya[1]	48	48	48	48	48	48	48	48	48	48	S
Cethana	85	85	85	85	85	85	85	85	85	85	S
Devils Gate	60	60	60	60	60	60	60	60	60	60	S
Fisher	43	43	43	43	43	43	43	43	43	43	S
Gordon[2]	375	378	387	396	405	411	417	423	429	429	S
John Butters	144	144	144	144	144	144	144	144	144	144	S
Lake Echo	0	32	32	32	32	32	32	32	32	32	S
Lemonthyme	51	51	51	51	51	51	51	51	51	51	S

Power station	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Class
Liapootah[1]	84	84	84	84	84	84	84	84	84	84	S
Mackintosh	80	80	80	80	80	80	80	80	80	80	S
Meadowbank	40	40	0	40	40	40	40	40	40	40	S
Poatina	0	300	300	300	300	300	300	300	300	300	S
Reece	232	232	232	232	232	232	232	232	232	232	S
Tamar Valley, CCGT	208	208	208	208	208	208	208	208	208	208	S
Tamar Valley, OCGT	58	58	58	58	58	58	58	58	58	58	S
Tarraleah	75	90	90	60	60	90	90	90	90	90	S
Trevallyn	94	94	94	94	94	94	94	94	94	94	S
Tribute	83	83	83	83	83	83	83	83	83	83	S
Tungatinah	100	103	81	109	134	134	134	134	134	134	S
Wayatinah[1]	39	39	39	39	39	39	39	39	39	39	S
Wilmot	31	31	31	31	31	31	31	31	31	31	S
Total	**2,130**	**2,483**	**2,430**	**2,477**	**2,511**	**2,547**	**2,553**	**2,559**	**2,565**	**2,565**	

1. Catagunya, Liapootah, and Wayatinah are scheduled together
2. Gordon Power Station's capacity is projected to increase incrementally year-by-year due to increasing water storage

Table 5-34—Summer aggregate scheduled and semi-scheduled generation capacities - Tasmania (MW)

Power station	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	Class
Bastyan	80	80	80	80	80	80	80	80	80	80	S
Bell Bay Three	120	120	120	120	120	120	120	120	120	120	S
Catagunya[1]	24	48	48	48	48	48	48	48	48	48	S
Cethana	85	85	0	85	85	85	85	85	85	85	S
Devils Gate	60	60	60	60	60	60	60	60	60	60	S
Fisher	43	43	0	43	43	43	43	43	43	43	S
Gordon[2]	378	384	393	399	408	414	420	426	432	429	S
John Butters	144	144	144	144	144	144	144	144	144	144	S
Lake Echo	32	32	32	32	32	32	32	32	32	32	S
Lemonthyme	51	51	51	0	51	51	51	51	51	51	S
Liapootah[1]	84	56	84	84	84	84	84	84	84	84	S
Mackintosh	80	80	80	80	80	80	80	80	80	80	S
Meadowbank	40	40	0	40	40	0	40	40	40	40	S
Poatina	300	250	300	250	250	250	300	300	300	300	S
Reece	232	232	232	232	232	232	232	232	232	232	S
Tamar Valley, CCGT	208	208	208	208	208	208	208	208	208	208	S
Tamar Valley, OCGT	58	58	58	58	58	58	58	58	58	58	S
Tarraleah	90	90	60	90	90	90	90	90	90	90	S
Trevallyn	67	67	94	94	74	94	94	94	94	94	S
Tribute	83	0	83	83	83	83	83	83	83	83	S

Power station	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	Class
Tungatinah	100	103	81	109	134	134	134	134	134	134	S
Wayatinah[1]	39	26	26	0	26	39	39	39	39	39	S
Wilmot	31	31	0	31	31	31	31	31	31	31	S
Total	**2,429**	**2,288**	**2,234**	**2,370**	**2,461**	**2,460**	**2,556**	**2,562**	**2,568**	**2,565**	

1. Catagunya, Liapootah, and Wayatinah are scheduled together
2. Gordon Power Station's capacity is projected to increase incrementally year-by-year due to increasing water storage

5.8.2 Changes since the 2009 ESOO (existing generation)

Aurora Energy Tamar Valley Power advises that the Tamar Valley CCGT revised its capacity from 203 MW to 208 MW during winter and from 196 MW to 208 MW during summer due to an output re-evaluation following operational experience.

Hydro Tasmania advises the following:

- Catagunya Power Station revised its capacity from 48 MW to 24 MW during summer 2010/11 due to planned maintenance on Unit 1.
- Cethana Power Station revised its capacity from 85 MW to 0 (zero) MW during summer 2012/13 due to planned maintenance.
- Fisher Power Station revised its capacity from 43 MW to 0 (zero) MW during summer 2012/13 due to planned maintenance.
- Lake Echo Power Station revised its capacity from 32 MW to 0 (zero) MW during winter 2011 due to planned maintenance.
- Lemonthyme Power Station revised its capacity from 51 MW to 0 (zero) MW during summer 2013/14 due to planned maintenance.
- Liapootah Power Station revised its capacity from 84 MW to 56 MW during summer 2011/12 due to planned maintenance on Unit 1.
- Meadowbank Power Station revised its capacity from 40 MW to 0 (zero) MW during winter 2013, summer 2012/13, and summer 2015/16 due to planned maintenance.
- Poatina Power Station revised its capacity from 300 MW to 0 (zero) MW during winter 2011 and from 300 MW to 250 MW during summer 2011/12, 2013/14, 2014/15, and 2015/16 due to planned maintenance.
- Tarraleah Power Station revised its capacity from 90 MW to 75 MW during winter 2011 and from 90 MW to 60 MW during summer 2012/13, winter 2014, and 2015 due to planned maintenance.
- Trevallyn Power Station revised its capacity from 94 MW to 67 MW during summer 2010/11 and 2011/12 due to planned maintenance on Units 4 and 3, respectively, and from 94 MW to 74 MW during summer 2014/15 due to planned maintenance on Unit 1.
- Tribute Power Station revised its capacity from 83 MW to 0 (zero) MW during summer 2011/12 due to planned maintenance.
- Tungatinah Power Station will receive upgrades to Units 1, 2, and 5, which will increase the station's capacity from 125 MW to 134 MW. Planned outages for the upgrades will take place in stages, with all works expected to be completed by summer 2013/14.
- Wayatinah Power Station revised its capacity from 39 MW to 26 MW during summer 2011/12, 2012/13, and 2014/15, and from 39 MW to 0 (zero) MW during summer 2013/14 due to planned maintenance.
- Wilmot Power Station revised its capacity from 31 MW to 0 (zero) MW during summer 2012/13 due to planned maintenance.

5.8.3 Committed project developments

AEMO is not aware of any scheduled or semi-scheduled generation projects in Tasmania that are currently classified as committed according to AEMO's commitment criteria.

Hydro Tasmania advises that Lower Lake Margaret is a non-scheduled hydroelectric plant, and is expected to be commissioned in the second quarter of 2010.

5.8.4 Plant limitations

The capacity of some plants may be restricted depending on water availability for generation or cooling.

5.8.5 Plant retirements

Bell Bay Power Station retired in 2009.

5.8.6 Historical generation levels and performance

Table 5-35 lists historical Tasmanian scheduled and semi-scheduled generation output from 2005/06-2009/10. Figures for 2009/10 are calculated on a pro-rata basis from May 2010.

Table 5-35—Historical scheduled and semi-scheduled generation (GWh) - Tasmania

Power station	2005/06	2006/07	2007/08	2008/09	2009/10 pro-rata
Bastyan	397	282	286	363	335
Bell Bay Three	0	39	31	32	34
Catagunya/Liapootah/Wayatinah	1,019	744	730	750	894
Cethana	457	263	309	387	374
Devils Gate	328	187	222	277	260
Fisher	256	141	162	228	210
Gordon	954	1,929	1,073	635	517
John Butters	564	409	394	468	518
Lake Echo	69	55	57	12	63
Lemonthyme	454	268	324	401	365
Mackintosh	404	282	286	361	337
Meadowbank	205	133	130	149	175
Poatina	1,178	1,046	766	547	847
Reece	1,052	757	776	923	929
Tamar Valley Combined Cycle (CCGT)	0	0	0	0	1,051
Tamar Valley Peaking (OCGT)	0	0	0	61	45
Tarraleah	594	551	506	518	560
Trevallyn	470	291	265	252	473
Tribute	232	178	177	202	220
Tungatinah	595	354	358	386	519
Bell Bay One	447	318	764	41	0
Bell Bay Two	168	609	447	588	0
Total	**9,843**	**8,836**	**8,063**	**7581**	**8,726**

5.8.7 Advanced and publicly announced proposals

AEMO sought information from generators and project proponents about the status of generation projects under development. Some companies provide AEMO with information that is commercial in confidence. Where this occurs, AEMO publishes as much publicly available information as possible.

Table 5-36 lists information about proposed generation projects in Tasmania.

More detailed information about advanced proposals includes the following:

- **Roaring 40s** advises that Musselroe Wind Farm is now an advanced proposal, and is expected to operate as semi-scheduled generation. Comprising 56 wind turbines with a total capacity of 168 MW, it is planned to be commissioned in 2013. The 2009 ESOO reported this as a publicly announced proposal.
- **Gunns** advises that the biomass-fuelled Pulp Mill Power Plant is an advanced proposal, and is expected to operate as scheduled generation. With a capacity of approximately 180 MW (90 MW anticipated to be used on site, and 90 MW for export to the grid), it is planned to be commissioned by 2013. The 2009 ESOO reported this as an advanced proposal.

See Section 5.8.3 for information about committed project developments.

Table 5-36—Advanced and publicly announced proposals - Tasmania

Company/operator	Project	Fuel/ Technology	Capacity (MW)	Commissioning date	Site	Major comp'ts	Planning consents/ construction approval/ EIS	Finance	Firm construct date Set	Status	Class
Eureka Funds Management	White Rock Wind Farm	Wind Turbine	Approx 400	2016	✓	-	-	-	-	Pub An	SS
Gunns	Pulp Mill	Biomass/ Thermal	180	2013	✓	✓	✓	-	-	Adv	S
Roaring 40s	Musselroe Wind Farm	Wind Turbine	168	2013	✓	-	✓	-	✓	Adv	SS

5.8.8 Non-scheduled generation

Table 5-37 lists information about non-scheduled generation in Tasmania.

Table 5-37—Existing and committed non-scheduled generation - Tasmania

Power station	Survey respondent	Fuel/ technology	Capacity (MW)	Anticipated capacity for winter MD (MW)	Anticipated capacity for summer MD (MW)
Butlers Gorge	Hydro Tasmania	Hydro	14	9	9
Cluny	Hydro Tasmania	Hydro	17	16	8
Paloona	Hydro Tasmania	Hydro	28	27	8
Repulse	Hydro Tasmania	Hydro	28	27	14
Rowallan	Hydro Tasmania	Hydro	11	5	6
Tods Corner	Hydro Tasmania	Hydro	1	1	1
Lake Margaret	Hydro Tasmania	Hydro	8	8	4
Remount Power Station	Infratil Energy	Thermal - Landfill Gas	2	2	2
Woolnorth Bluff Point Wind Farm	Roaring 40s	Wind	65	65	65
Woolnorth Studland Bay Wind Farm	Roaring 40s	Wind	75	75	75
Committed non-scheduled generation					
Lower Lake Margaret	Hydro Tasmania	Hydro	3	3	1

5.9 Wind study

AEMO's generator survey results indicate a large number of proposed wind generation projects, with continued investment growth expected due to government incentives such as the national Renewable Energy Target (RET) scheme.

The intermittent nature of wind generation presents unique operational issues for the NEM. As a result, AEMO has been monitoring the effects of intermittent wind generation, particularly in South Australia, where the largest proportion of wind generation is installed. This section presents a South Australian wind case study to examine the effects of wind generation on the electricity network.

5.9.1 Wind variability

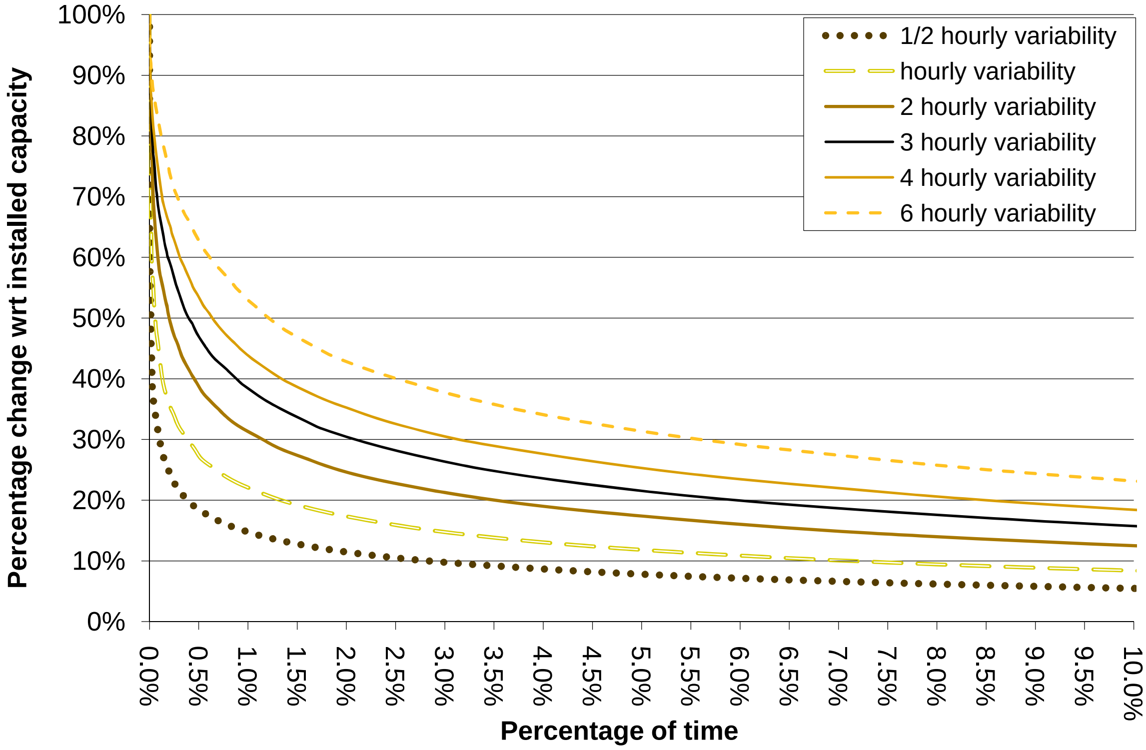
The amount of energy being generated by wind can vary significantly over a short period. For example, from 1 July 2009 to 1 May 2010, the largest half-hour increase in wind generation was 223 MW, occurring from 5:30 pm to 6:00 pm on 8 December 2009. The largest half-hour decrease of 135 MW occurred two hours later.

Figure 5-2 shows wind variability as a proportion of total installed capacity in South Australia from 2003 to 2010.

Half-hourly wind variations are quite small most of the time, with changes in half-hourly variability being approximately 5% or less of installed capacity for almost 90% of the time. More significant variations did occur, however, with 16 occurrences of variations in excess of half of the installed capacity.

Shifts in variability tend to be larger over longer periods of time. For example, changes in six-hourly variability were up to 23% of installed capacity for 90% of the time.

Figure 5-2—Wind variability as a proportion of total installed capacity in South Australia, 2003-2010

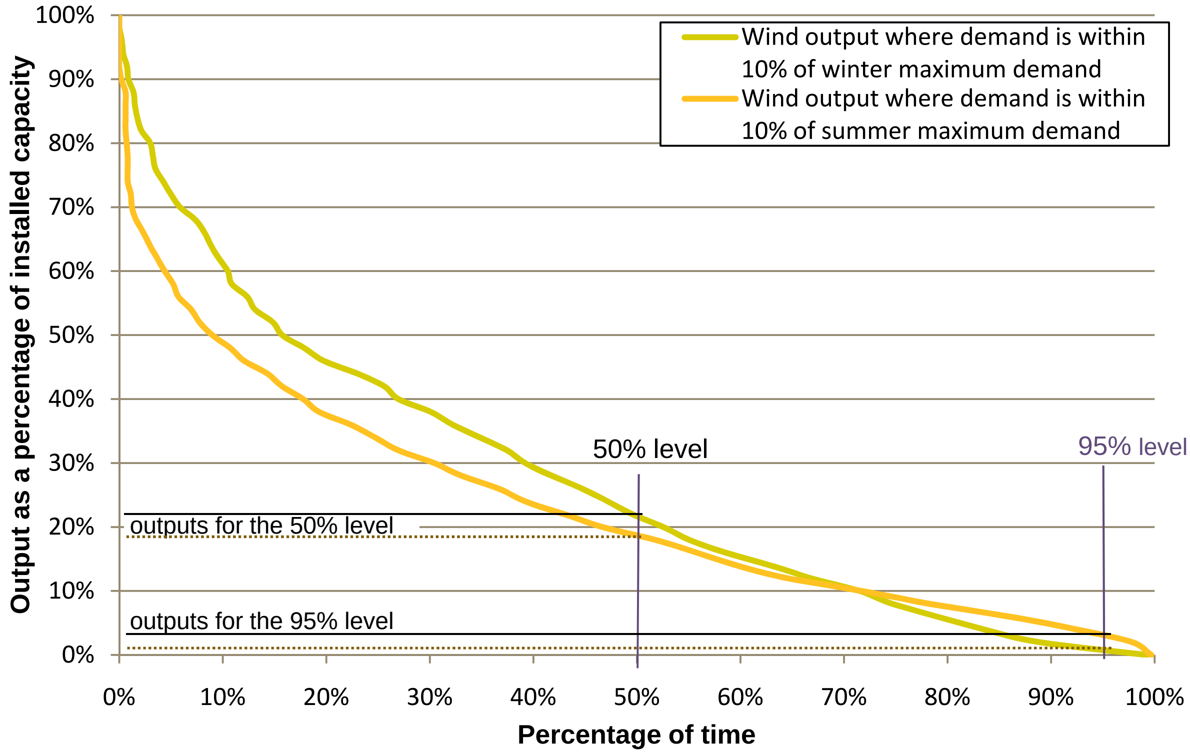


5.9.2 Wind contribution during peak demand periods

When considering the firm contribution of wind generation to peak demand, AEMO considers that an appropriate level of dependability must at least match other generation types. A 5% level of unavailability due to forced outages is at the low end of acceptable performance, and has been used in this analysis to establish the proportion of wind generation installed capacity that can be considered to be operating reliably at times of peak demand.

Figure 5-3 shows the contribution of wind generation as a proportion of the winter and summer MD in South Australia. The 95% line represents a reasonable level of availability.

Figure 5-3—Wind generation during peak demand in South Australia



During the top 10% of summer peak demand periods, approximately 3% of total wind generation installed capacity contributed to demand for 95% of the time. During the top 10% of winter peaks, approximately 1% contributed for 95% of the time.

Similar analysis has been performed in other regions as wind farms have been installed.

Table 5-38 lists the contribution factors for wind used in the supply-demand outlook.

Table 5-38—Wind contribution during peak demand periods

Region	Summer	Winter
Queensland	0%	0%
New South Wales	5%	5%
Victoria	8%	5.5%
South Australia	3%	1%
Tasmania	0%	0%

5.9.3 Wind performance during the South Australian heatwave

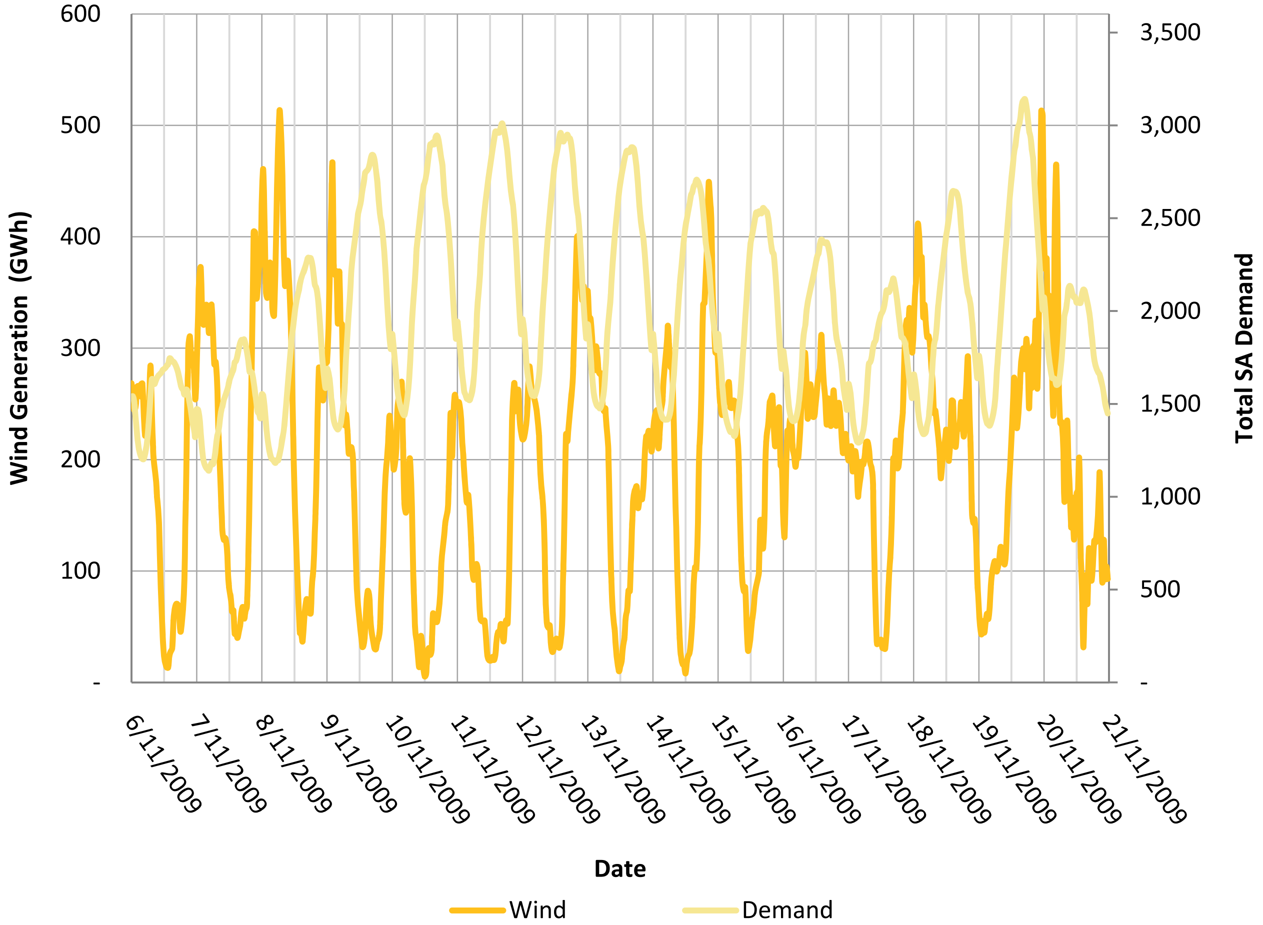
South Australia experienced an unseasonal heatwave during November 2009. Table 5-39 lists the maximum daily temperatures over this period.

Table 5-39—South Australian heatwave temperatures, 7-19 November 2009

Date	7th	8th	9th	10th	11th	12th	13th	14th	15th	16th	17th	18th	19th
Day	Sa	Su	Mo	Tu	We	Th	Fr	Sa	Su	Mo	Tu	We	Th
Max Temp (°C)	34.4	36.7	37	38.9	39.2	39.2	38.7	39.5	39.4	31.9	29	38.9	43

During the heatwave, wind generation peaked at 513 MW on 8 November 2009 and demand peaked at 3,141 MW on 19 November 2009. While wind generation contributed to meeting demand during this period, it also tended to decrease during the peak demand periods on most days. Figure 5-4 shows this trend, with the demand on the days immediately before and after the heatwave shown to demonstrate normal demand. The reduction in wind generation during peak periods, or at the hottest times of the day, is partially attributed to limits placed on some turbines at high temperatures to prevent overheating.

Figure 5-4—Wind generation and total South Australian demand, 6-21 November 2009



Chapter 6 – Reliability and Minimum Reserve Levels

6.1 Summary

This chapter describes aspects of power system operation relating to reliability, with a specific focus on the calculation and application of Minimum Reserve Levels (MRLs) as an operational indicator of long-term system reliability.

AEMO has recently recalculated the MRLs (last calculated in 2006) to ensure their continued appropriateness as the power system evolves. This is an important process because capacity adequacy is particularly sensitive to demand growth in and between regions, the location and reliability of installed plant, and any changes to the network topology.

For the purposes of the Electricity Statement of Opportunities (ESOO), the adequacy of reserve is measured against the MRLs presented in this chapter. See Chapter 7 for information about the 10-year outlook adequacy assessment, which covers a range of demand growth assumptions.

6.2 Reliability and minimum reserve levels

This section provides a brief overview of the concept of reliability and its relationship with the MRLs.

6.2.1 Reliability and the Reliability Standard

In the context of the National Electricity Market (NEM), reliability refers to the likelihood of having sufficient supply to meet demand. Reliability is measured as the accumulated energy that is not met over a given timeframe, and is expressed as a percentage relative to the total energy requirement over the same timeframe.

The Reliability Standard, established by the Australian Energy Market Commission's (AEMC) Reliability Panel, defines a minimum acceptable level of reliability to be met in each region. The Reliability Standard currently specifies that no more than 0.002% of the annual energy consumption of a region should be at risk of not being met over the long term. The Reliability Panel reviews the form and value of the Reliability Standard every two years, and completed its most recent review in April 2010 (see Section 6.5.2 for more information).

6.2.2 Establishing minimum reserve levels

AEMO is required to ensure the Reliability Standard is met operationally. To apply this long-term measure in an operational environment, AEMO translates the Reliability Standard into a safety margin of local installed capacity for each region. By convention, this margin is expressed relative to a region's 10% probability of exceedence (POE) maximum demand (MD) and is referred to as a minimum reserve level (MRL).

MRLs are used in both medium and long-term forecasting to assess whether the level of available capacity is sufficient to satisfy the Reliability Standard.

In the medium term, the Medium-term Projected Assessment of System Adequacy (MT PASA) applies the MRLs to produce a two-year outlook at daily resolution. This assessment incorporates the scheduled maintenance pattern of generating units and transmission assets. MT PASA is published weekly and provides information to the market about times when there is a high likelihood of experiencing a low reserve condition. Under these conditions, AEMO may need to intervene through the Reliability and Emergency Reserve Trader (RERT) process.

In the long term, the supply-demand outlook (see Chapter 7) applies the MRLs to produce a 10-year outlook at annual resolution. The supply-demand outlook is intended to provide market participants and other interested parties with information about the timing and magnitude of the additional investment required in the long term to maintain the Reliability Standard.

The MRLs are also applied in the National Transmission Network Development Plan (NTNDP) and represent a minimum level of new capacity that must be installed in the projected system.

Calculating minimum reserve levels

MRLs are calculated using a detailed suite of market simulations that incorporate the effects of varying weather conditions and generator outage patterns. The simulation analysis produces a minimum amount of installed generation that is required to meet the Reliability Standard in all regions. A reserve sharing process is then performed that reflects the actual reserves available in the system in an attempt to align the years in which low reserve conditions occur across the NEM (see Section 6.3.1 for more information about these adjustments).

The 2010 ESOO CD includes two video tutorials that provide additional information about the concept of MRLs and their relationship with long-term system reliability.

Energy limitations and the minimum reserve levels

The supply-demand outlook and MT PASA use generation capacity advice provided by NEM generators but do not account for possible energy limitations. Accounting for possible energy limitations becomes particularly important when determining the likely impacts of drought, or when assessing the reliability of regions with significant hydroelectric generation.

AEMO assesses the impact of energy limitations through the quarterly Energy Adequacy Assessment Projection (EAAP) studies. These studies use time-sequential market simulations to provide a two-year outlook that quantifies the impact of energy constraints under a range of scenarios. The latest EAAP results were published in June 2010 and are available from the AEMO website[43].

6.3 Minimum reserve levels

As part of the 2010 MRL recalculation process, AEMO determined appropriate MRL values for the 2010/11 and 2011/12 financial years. The MRLs were implemented in MT PASA on 6 July 2010.

For the purposes of the supply-demand outlook, the 2011/12 MRLs were adjusted to apply from 2012/13 onwards, and take advantage of changes in surplus reserves between Victoria and South Australia (see Section 6.3.1 for more information about the application of reserve sharing).

[43] http://www.aemo.com.au/electricityops/eaap.html.

Table 6-1 lists the MRLs used in both MT PASA and the supply-demand outlook.

Table 6-1—MRLs, 2010/11-2012/13 (MW)

Year	Queensland	New South Wales	Victoria	South Australia	Tasmania[1]
2010/11	829	-1,548	653	-131	144
2011/12	913	-1,564	530	-268	144
2012/13 onward[2]	913	-1,564	176	-116	144

1. The Tasmanian region is largely energy limited, rather than capacity limited. As a result, the Tasmanian MRL remains unchanged at the size of the pre-existing Tasmanian Capacity Reserve Standard. The MRL recalculation process confirmed that this value remains sufficient to meet (or exceed) the Reliability Standard.
2. The 2012/13 MRL applies only in the supply-demand outlook presented in Chapter 7.

Net import limits

To assess a region's capacity to meet its MRL, the supply-demand calculator and MT PASA implement net import limits that restrict the amount of spare capacity a region can import. To ensure consistency between the assessment of reserve margins and the calculation of MRLs, the MRLs described in Table 6-1 include a corresponding assumption about the level of import.

The import limitations, listed in Table 6-2, are applied only in the supply-demand calculator and PASA outlook calculations and do not limit actual interconnector power transfers in central dispatch.

Table 6-2—Net import limits (MW)

	Queensland	New South Wales	Victoria	South Australia	Tasmania
Net import limit (MW)	0[1]	-330	940	0[1]	N/A[2]

1. This region has a local MRL requirement. This means the region cannot rely on support from neighbouring regions when meeting its MRL requirements.
2. Net import limits are not applied to Tasmania's capacity adequacy assessment. Tasmania's MRL is set at the size of the pre-existing Tasmanian Capacity Reserve Standard, and is independent of any assumed interconnector power flow.

6.3.1 Reserve sharing adjustments

The 2010 MRL calculation process explored and quantified the ability for neighbouring regions to share surplus reserves. These relationships allow the MRLs to be optimised based on changing system conditions, so that regions with excess available capacity can support regions that are unable to meet their MRL locally.

The capability for regions to share reserve surpluses is largely dictated by demand diversity between the regions, network losses, and interconnector limitations. The result of these interactions is that sharing spare reserve between regions is generally not a 1:1 relationship (in other words, to reduce the MRL in a region by 1 MW, the MRL in a neighbouring region will need to be increased by more than 1 MW).

The National Electricity Rules (NER) require MT PASA to use a set of MRLs that define reserve in terms of individual regions. This means the MRL optimisation process must be performed manually, outside of the MT PASA system. AEMO is currently progressing a NER change to allow MT PASA (and subsequently the supply-demand outlook) to dynamically perform this optimisation process.

AEMO established optimal reserve sharing adjustments for use in MT PASA for the 2010/11 and 2011/12 financial years, and for use in the supply-demand outlook from 2012/13 onwards. AEMO may re-optimise the calculated adjustments when assessing the need for market intervention.

Table 6-3 presents the reserve sharing adjustments determined for each year. These adjustments are already included in the MRL values presented in Table 6-1.

Table 6-3—Reserve sharing adjustments, 2010/11-2012/13 (MW)

Applicable year	Queensland	New South Wales	Victoria	South Australia	Tasmania
2010/11	0	0	+314	-150	0
2011/12	0	0	+233	-100	0
2012/13 onwards	0	0	587	-252	0

In all cases, reserve sharing has only been performed for the Victorian and South Australian regions. These regions exhibit significant sharing capability because there is a relatively high level of demand correlation between the regions. This means that installed capacity, rather than interconnection, is often the limiting factor. Because Victoria has significantly more installed capacity than its MRL requires, some of this can be utilised to support the South Australian region's reserve requirement.

The remaining regions show little ability to share excess reserves because of significant diversity and restricted interconnection capabilities. In particular, at times of peak demand in one region, neighbouring regions are generally able to provide capacity support up to the network limits. This means there is no further headroom to import neighbouring surplus reserves and any reserve sharing opportunities have already been captured in the unadjusted MRLs.

6.3.2 Explanation of changes to the MRL values

Table 6-4 compares the MRLs calculated in the 2006 studies (applied in MT PASA until 6 July 2010) with the MRLs calculated in 2010 (applied in MT PASA from 6 July 2010 onwards). While there have been sizeable changes to the input data and methodology used to calculate the latest MRLs, the overall net change from the previous values is relatively modest in most regions.

Table 6-4—Comparison of MRLs, 2006 and 2010 (MW)

Time in force	Queensland	New South Wales	Victoria	South Australia	Tasmania[1]
Before 6 July 2010	560	-1,430	665	-50	144
After 6 July 2010	829	-1,548	653	-131	144
Difference	**+269**	**-118**	**-12**	**-80**	**0**

1. The Tasmanian region is largely energy limited, rather than capacity limited. As a result, the Tasmanian MRL has been left unchanged at the size of the pre-existing Tasmanian Capacity Reserve Standard. Studies were performed to confirm that this value remains sufficient to meet (or exceed) the Reliability Standard.

A significant body of work was undertaken to justify the validity of these changes and five key contributing factors were identified:

- **Generator reliability**—Forced outage rates have changed due to aging plant and improved data collection. In addition to this, the mix of installed generation technologies has also changed. Some regions have seen an increase in the proportion of gas-fired generation, which typically delivers lower reliability than black-coal generation.
- Both these changes modify the effective availability of generation to meet demand in a region, and so affect the amount of plant required for a given demand level.
- **The shape of demand**—The shape of regional demand has changed since the previous MRL studies, particularly near the peaks. Reserve shortfall events typically occur near the regional MDs, and changing the length of time that the system is exposed to these high levels of demand has a significant impact on the calculated MRLs.

- **Consideration of extreme demands**—The 2010 MRL studies have applied an enhanced methodology for considering extreme demand outcomes. In particular, The 2010 studies are better able to capture long-term expected unserved energy results that generally do not follow a normal distribution and exponentially increase in severity for higher peak demand values.
- **Demand diversity assumptions**—The 2006 MRL studies modelled an artificially low level of demand diversity between regions, which forced all regions to achieve their MD values in the same week. This significantly reduced the ability for regions to support each other at times of peak demand.
- The 2010 MRL studies model diversity based on a historical year (2005/06) to reflect the diversity of demand under relatively consistent POE weather conditions. This has resulted in downward pressure on the new MRLs, as regions are better able to utilise spare capacity in adjoining regions during peak demand periods.
- See the 2010 MRL Recalculation Final Report for more information about these changes[44].

6.4 The implications of MRL change

Changing the MRL value for a region can affect the timing of projected reserve shortfalls and the magnitude of the additional capacity required to avoid them.

In the medium term, these changes are captured by the weekly MT PASA runs, which provide an indication of expected reserve shortfalls over the coming two years. In the longer term, these changes are captured by the supply-demand outlook (see Chapter 7).

Table 6-5 compares the magnitude and timing of the first forecast reserve shortfall in each region in the 2009 ESOO with this year's results. In addition to using new MRL values, the change in low reserve condition (LRC) points is also a result of revised demand and generation capacity projections.

Table 6-5—Comparison of 2009 and 2010 supply-demand outlook results, medium growth

Region	2009 ESOO		2010 ESOO	
	LRC point	Reserve deficit (MW)	LRC point	Reserve deficit (MW)
Queensland	2014/15	34	2013/14	726
New South Wales	2015/16	182	2016/17	27
Victoria	2013/14	17	2015/16	249
South Australia	2012/13	68	2015/16	50
Tasmania - summer	>2019/20	N/A	>2019/20	N/A
Tasmania - winter	-	-	>2020	N/A

Likelihood of intervention

Reserve shortfalls assessed in MT PASA can trigger AEMO interventions that carry financial implications for the affected market participants, and the jurisdictions in which intervention is required. The likelihood of reaching a reserve trading situation requiring instigation of the RERT process is directly related to the magnitude of MRL applied in each region.

[44] http://www.aemo.com.au/electricityops/mrl.html

The decrease in MRL for all regions except Queensland indicates that reserve shortfalls are now less likely in those regions. In other words, AEMO now believes these regions are able to meet the Reliability Standard with a lower capacity margin.

Queensland, on the other hand, has seen a significant increase in MRL, and so is likely to require intervention sooner unless additional investment occurs locally. However, as identified in Table 6-5, under medium economic growth assumptions there is sufficient existing and committed generation to satisfy all regional reserve requirements (including Queensland) until at least 2013/14.

6.5 Reliability reviews

This section presents an overview of reviews and NER change proposals related to reliability and the MRLs.

6.5.1 Review of Operationalisation of the Reliability Standards

On 3 March 2009, the Australian Energy Market Commission (AEMC) approved terms of reference for the Review of Operationalisation of the Reliability Standards[45]. Specifically, the AEMC requested that the Reliability Panel review the methodology and process used by AEMO for calculating the MRLs, especially when they apply to more than one region.

On 21 December 2009, the Reliability Panel published its final report. The Panel did not recommend any specific changes to AEMO's current methodology for calculating MRLs and applying them within operational tools.

6.5.2 Review of the Reliability Standard and Settings

On 3 March 2009, the AEMC approved terms of reference for the Review of the Reliability Standard and Settings[46]. The reliability settings include the market price cap, the cumulative price threshold, and the market floor price.

On 30 April 2010, the Reliability Panel published its final report and the determination to retain the current form of the Reliability Standard and its value of 0.002% regional energy. In addition, the panel recommended that, from 1 July 2012, the market price cap of $12,500/MWh and the cumulative price threshold of $187,500/MWh be increased annually in real terms in accordance with the producer price index. The Reliability Panel recommended no change to the market floor price, which remains -$1,000/MWh.

6.5.3 Amendments to PASA-related Rules

On 29 April 2010, AEMO submitted a NER change request to the AEMC[47] to amend NER provisions relating to PASA processes. In particular, AEMO sought to remove its obligation to prepare and publish the reserve requirements used in MT PASA for each region. The amended Rule will allow

[45]http://aemc.gov.au/Market-Reviews/Completed/Review-of-Operationalisation-of-the-Reliability-Standards.html

[46]http://aemc.gov.au/Market-Reviews/Completed/Review-of-the-Reliability-Standard-and-Settings.html

[47]http://aemc.gov.au/Electricity/Rule-changes/Open/Amendments-to-PASA-related-Rules.html

AEMO to use reserve requirements that apply across multiple regions so that MT PASA can more optimally share medium-term capacity reserves.

On 3 June 2010, the AEMC commenced initial consultation on this NER change proposal.

Chapter 7 – Supply-Demand Outlook

7.1 Introduction

This chapter provides information to existing and potential investors about the future adequacy of electricity supplies in the National Electricity Market (NEM) with particular respect to the Reliability Standard.

A supply-demand outlook is presented for each region and highlights potential generation and demand-side investment opportunities due to projected shortfalls in existing and committed supply. In particular, the regional outlooks identify the timing of low reserve conditions (LRC), indicating where reserve margins will fall below the minimum reserve level (MRL). Under these conditions, the Australian Energy Market Operator (AEMO) may investigate the need for market intervention to maintain power system reliability.

The supply-demand outlook focuses on summer because scheduled and semi-scheduled maximum demand (MD) is generally higher in summer than in winter (except in Tasmania). Thermal generation capacities and power transfer capabilities generally also decrease over summer, increasing the likelihood of low reserve conditions.

The supply-demand outlook has traditionally presented a long-term assessment over a 10-year outlook period. In recognition of the differing market signals and data confidence across this timeframe, AEMO has decided to separate the 10-year adequacy assessment:

- The Power System Adequacy (PSA)–A Two Year Outlook focuses on supply adequacy and market intervention triggers in the first two years.
- The Electricity Statement of Opportunities (ESOO) and the supply-demand outlook focus on aspects of supply adequacy that may influence investment decisions in years three to ten.

7.2 Power system reliability assessments in the NEM

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

7.2.1 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 2 years. This shorter time-frame enables MT PASA to consider more detailed system information available in the short-term, including the scheduled maintenance pattern of generating units and transmission assets.

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. Alternatively, the supply-demand outlook is intended to provide participants and other interested parties with information about the timing and magnitude of the additional investment required in the long term to maintain the Reliability Standard.

Table 7-1 lists points of comparison between MT PASA and the supply-demand outlook.

Table 7-1—MT PASA and the supply-demand outlook

	MT PASA	Supply-demand outlook
Objective	Allocates capacity to each region to meet demand plus MRLs. Reserve deficits are shared with adjacent regions	Allocates capacity to each region to maximise overall reserves. Reserve deficits are shared with adjacent regions
Outlook	2 years	10 years
Resolution	Daily	Yearly
Updated	Weekly	Yearly
Inputs		
Demand	Projected daily 10% probability of exceedence (POE) scheduled and semi-scheduled MD, less committed DSP	Projected seasonal 10% POE scheduled and semi-scheduled MD, less committed DSP
Generation	Maintenance outages and short-term variations considered	Generating plant availability assumed at stated summer and winter capacity. Long-term variations considered
Semi-scheduled generation	Calculates semi-scheduled (wind farm) available capacity according to latest wind forecasts (AWEFS system)	Calculates semi-scheduled (wind farm) available capacity according to availability factors used by the jurisdictional planning bodies (JPBs) in producing the demand forecasts
Energy capacity	Energy limitations modelled through bid availability, which is managed by generators	Energy limitations not modelled, except where stated as capacity reductions
Network	Network maintenance outages considered	System normal operating considerations assumed
Outputs		
Determine	Reserve levels at daily peak demand, and LRC points	Reserve levels at summer or winter peak demand, and LRC points
Indicate	Opportunities for market response (up to two years out)	Opportunities for market response (in years three to ten years)
AEMO action	Possible intervention through RERT process	No action – market information purposes only

7.2.2 The Power System Adequacy—A Two-Year Outlook

The annual PSA supplements the ESOO by providing a detailed investigation of near-term supply issues. In particular, system adequacy is measured against several key indicators including capacity reserve, energy reserve, frequency control, voltage control, and interconnector capability.

7.2.3 The Energy Adequacy Assement Projection

The supply-demand outlook and MT PASA use generation capacity advice provided by NEM generators but do not account for possible energy limitations. Accounting for possible energy limitations becomes particularly important when determining the likely impacts of drought, or when assessing the reliability of regions with significant hydroelectric generation.

AEMO assesses the impact of energy limitations through the quarterly EAAP studies. These studies use time-sequential market simulations to provide a two-year outlook that quantifies the impact of energy constraints under a range of scenarios. The latest EAAP results were published in June 2010 [48].

7.3 The supply-demand calculator

AEMO uses the supply-demand calculator to generate 10-year reliability outlooks for each region. The supply-demand calculator is a spreadsheet tool that employs a linear programming approach to co-optimise generation dispatch and interconnector flows subject to minimising reserve deficits.

Where applicable, the calculator shares reserve deficits between regions in proportion to their scheduled and semi-scheduled MDs (subject to transmission network limitations and regional net import limits).

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

- regional scheduled and semi-scheduled MD projections for the high, medium, and low economic growth scenarios (see Chapter 4)
- levels of committed demand-side participation (DSP) (see Chapter 4, Section 4.10)
- capacities of existing and committed scheduled and semi-scheduled generation including committed retirements (see Chapter 5)
- regional MRLs and net import limits (see Chapter 6), and
- existing transmission capabilities and committed transmission projects (see Appendix E).

The 2010 ESOO CD includes a version of the supply-demand calculator, enabling interested parties to vary assumptions and assess alternative scenarios.

The ESOO CD 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.

7.3.1 Modelling network capability

The supply-demand calculator models transmission network capability using a set of system normal network constraint equations developed for the National Transmission Network Development Plan (NTNDP), and based on AEMO’s Market Management System (MMS). These constraint equations are adjusted to take account of advice from the Jurisdictional Planning Bodies (JPBs) about how network capabilities might vary with time and operating conditions, including committed transmission projects (see Appendix D for more information about the committed transmission projects included in the supply-demand calculator).

Network constraint equations are periodically revised and interested parties should confirm the relevance of the implemented equations prior to using the calculator. The calculator also purposely disables some equations to avoid violating constraint equations and anomalous dispatch outcomes. See Attachment 2 for more information about these constraint equations.

[48] http://www.aemo.com.au/electricityops/eaap.html

7.3.2 Minimum reserve level optimisation

As part of the 2010 MRL calculation, reserve sharing relationships were determined across each region boundary. These relationships allow the MRLs to be optimised based on changing system conditions so that regions with excess available capacity can support regions that are unable to meet their MRL locally. Reserve sharing tends to result in neighbouring regions reaching their LRC points in the same year.

The MRLs applied in MT PASA have been optimised using system data for 2010/11 and 2011/12. For the purposes of the supply-demand calculator, the MRLs were subsequently reoptimised (where possible) to apply from 2012/13 onwards. In particular, the South Australian MRL was increased to support the Victorian reserve requirement in light of relative changes to the MD and capacity projections for both regions.

The National Electricity Rules (NER) currently dictate that MT PASA must use a set of MRLs that define reserve in terms of individual regions. This means the MRL optimisation process must be performed manually, outside of the MT PASA system. AEMO is currently progressing a NER change to allow MT PASA (and subsequently the supply-demand outlook) to dynamically perform this optimisation process.

See Chapter 6, Section 6.3.1, for more information about regional reserve sharing relationships and their application in the MRLs.

7.4 Supply-demand outlook results

This section presents the supply-demand outlook for each region. In particular, it shows projected low reserve condition timings and the magnitude of the reserve deficit. An LRC point represents a shortfall against the regional MRL, suggesting an increased likelihood of AEMO's intervention to maintain power system reliability. It does not imply that load shedding will occur.

The outlook assessment for each region commences in summer 2012/13. See AEMO's weekly MT PASA results[49] and annual Power System Adequacy Two-Year Outlook report[50] for information about supply adequacy for 2010/11 and 2011/12.

7.4.1 Summary of low reserve condition points and reserve deficits

Table 7-2 lists an overview of the supply-demand outlook results for 2010. The LRC point indicates the first year that a region's reserve is projected to fall below the MRL, and the reserve deficit indicates by how much. The LRC point is calculated using 10% POE MD projections and assumes no further capacity enters the market beyond what is already committed (see Chapter 5 for more information about which generation projects are considered committed).

In addition to providing a summarised outlook for the medium economic growth scenario, Table 7-2 also provides sensitivity results for the low and high economic growth scenarios. In general, increasing the rate of growth tends to either bring regional LRC points forward in time or increase the reserve deficit experienced in a particular year.

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[49] http://www.aemo.com.au/data/outlook.html

[50] http://www.aemo.com.au/electricityops/psa2010.html

Table 7-2–Supply-demand outlook overview

Region	Low economic growth		Medium economic growth		High economic growth	
	LRC point	Reserve deficit (MW)	LRC point	Reserve deficit (MW)	LRC point	Reserve deficit (MW)
Queensland	2015/16	184	**2013/14**	**726**	2012/13	716
New South Wales	2017/18	91	**2016/17**	**27**	2016/17	285
Victoria	2017/18	135	**2015/16**[1]	**249**	2014/15	222
South Australia	2017/18	11	**2015/16**[1]	**50**	2012/13	85
Tasmania (summer)	>2019/20	N/A	**>2019/20**	**N/A**	>2019/20	N/A
Tasmania (winter)	>2020	N/A	**>2020**	**N/A**	>2020	N/A

1. As described in Section 7.3.2, the Victorian and South Australian MRLs allow significant flexibility for reserve sharing between these regions. This results in coincident LRC points
2. The regional outlooks examined in the remainder of this section provide graphical results for the medium economic-growth scenario only. See Attachment 2 for a full set of results for the additional growth sensitivities

7.4.2 Interpereting the supply-demand outlook

Each region's summer supply-demand outlook and its LRC point is presented as a graph of supply adequacy trends. Figure 7-1 provides a guide to interpreting the outlooks and their key terms, which are defined as follows.

Capacity for Reliability

This represents the capacity (comprising local generation plus net import) required to meet the region's MRL. The MRLs are calculated to ensure sufficient supplies are available to meet the Reliability Standard (see Chapter 6 for more information).

$$Capacity\ for\ Reliability$$

$$= 10\%\ POE\ Scheduled\ and\ Semi\text{-}Scheduled\ MD$$

$$+ Minimum\ Reserve\ Level$$

$$- Committed\ Demand\text{-}Side\ Particpation$$

Allocated Installed Capacity

This represents the current projection of installed generation capacity allocated to a region. The supply-demand calculator allocates regional imports and exports to minimise reserve deficits. Reserve deficits are shared in proportion to the MD for each region up to the interconnector limits.

Net regional imports can be either positive (net import into the region) or negative (net export from the region).

$$Allocated\ Installed\ Capacity$$

$$= Regional\ Scheduled\ and\ Semi\text{-}Scheduled\ Generation$$

$$+ Net\ Regional\ Import$$

Additional Capacity Required

This represents the amount a region's allocated installed capacity falls short of the capacity required for reliability. It is also referred to as the 'reserve deficit' and is capped at a minimum value of 0 (zero) MW.

$$Additional\ Capacity\ Required$$

$$= Capacity\ for\ Reliability$$

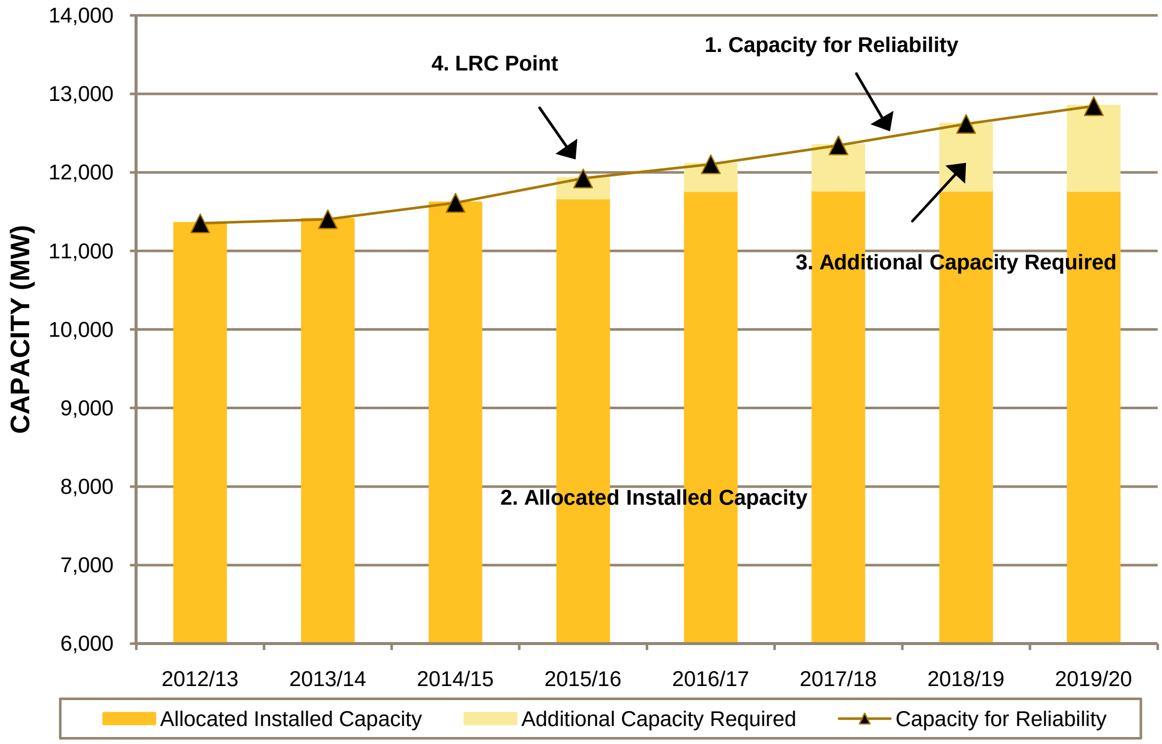
$$- Allocated\ Installed\ Capacity$$

LRC Point

This represents the first year that the projected allocated installed capacity falls below the capacity for reliability (the year the region's reserve falls below the MRL).

An LRC point does not imply that load shedding will occur. Continued operation with a low reserve, however, indicates the system may not meet the Reliability Standard in the long term.

Figure 7-1—Interpreting the supply-demand outlook



7.4.3 Queensland summer outlook

Figure 7-2 presents the projected Queensland summer supply-demand outlook for 2012/13-2019/20.

The figure indicates that, with medium economic growth, Queensland reaches its LRC point in 2013/14, requiring an additional 726 MW of local capacity to delay this shortfall until the following year.

The 2009 ESOO reported a Queensland LRC point in 2014/15, one year later than the new projection. This is primarily due to an increase in the Queensland MRL and a decrease in forecast available capacity. In particular, capacity reductions result from the progressive retirement of Swanbank B by 2012/13.

Table 7-3 compares the medium economic growth results (shown in Figure 7-2) with the results assuming high and low economic growth (see Chapter 4 for more information about the demand forecast scenarios).

High economic growth moves the Queensland LRC point forward by one year to 2012/13. Low economic growth delays the LRC point by two years until 2015/16.

See Attachment 2 for more information about the results from the alternative demand forecast scenarios.

Figure 7-2—Queensland summer supply-demand outlook

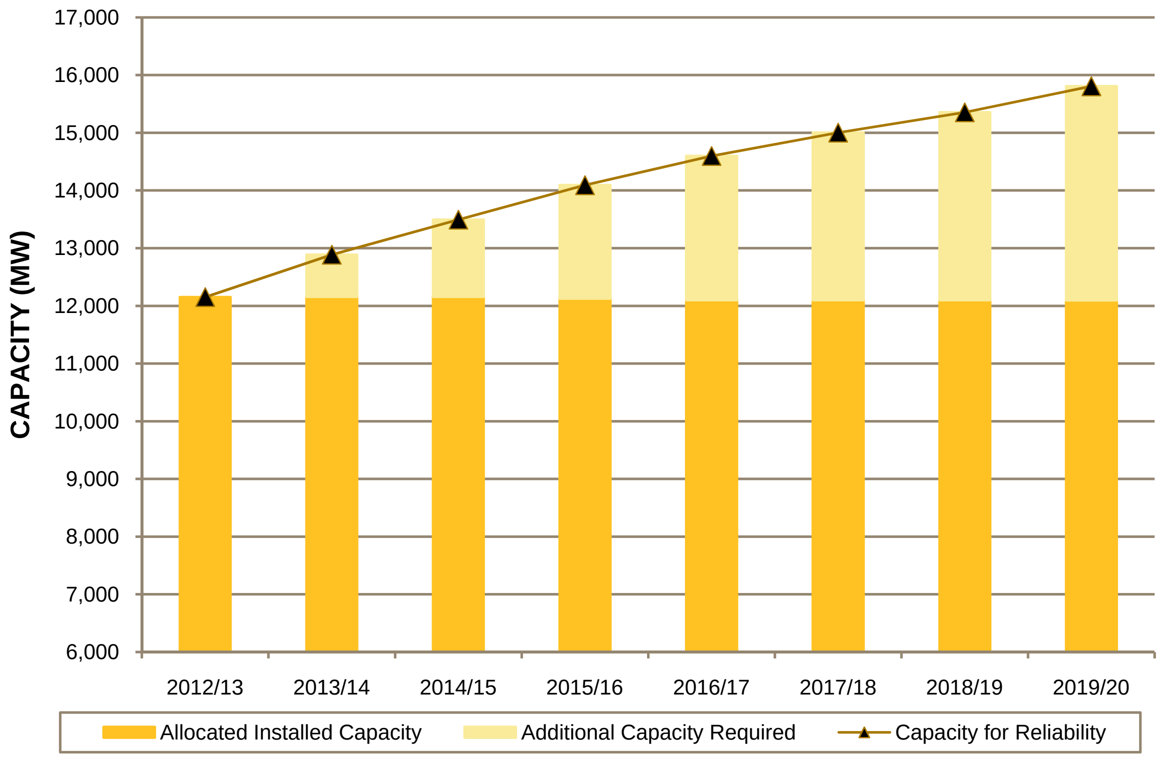


Table 7-3—Queensland supply-demand outlook summary

Region	Low economic growth		Medium economic growth		High economic growth	
	LRC point	Reserve deficit (MW)	LRC point	Reserve deficit (MW)	LRC point	Reserve deficit (MW)
Queensland	2015/16	184	**2013/14**	**726**	2012/13	716

7.4.4 New South Wales summer outlook

Figure 7-3 presents the projected New South Wales summer supply-demand outlook for 2012/13-2019/20.

The figure indicates that, with medium economic growth, New South Wales reaches its LRC point in 2016/17, requiring an additional 27 MW of local capacity to delay this shortfall until the following year.

The 2009 ESOO reported a New South Wales LRC point of 2015/16, one year earlier than the new projection. This is due to a decrease in the New South Wales MRL, an increase in regional capacity (see Chapter 5, Section 5.5.2, for more information), and a change in the maximum demand forecasts.

Table 7-4 compares the medium economic growth results (shown in Figure 7-3) with the results assuming high and low economic growth (see Chapter 4 for more information about the demand forecast scenarios).

There is no change to the New South Wales LRC point with high economic growth. There is, however, a significant increase in the reserve deficit projected for that year. Low economic growth delays the LRC point by one year until 2017/18.

See Attachment 2 for more information about the results from the alternative demand forecast scenarios.

Figure 7-3—New South Wales summer supply-demand outlook

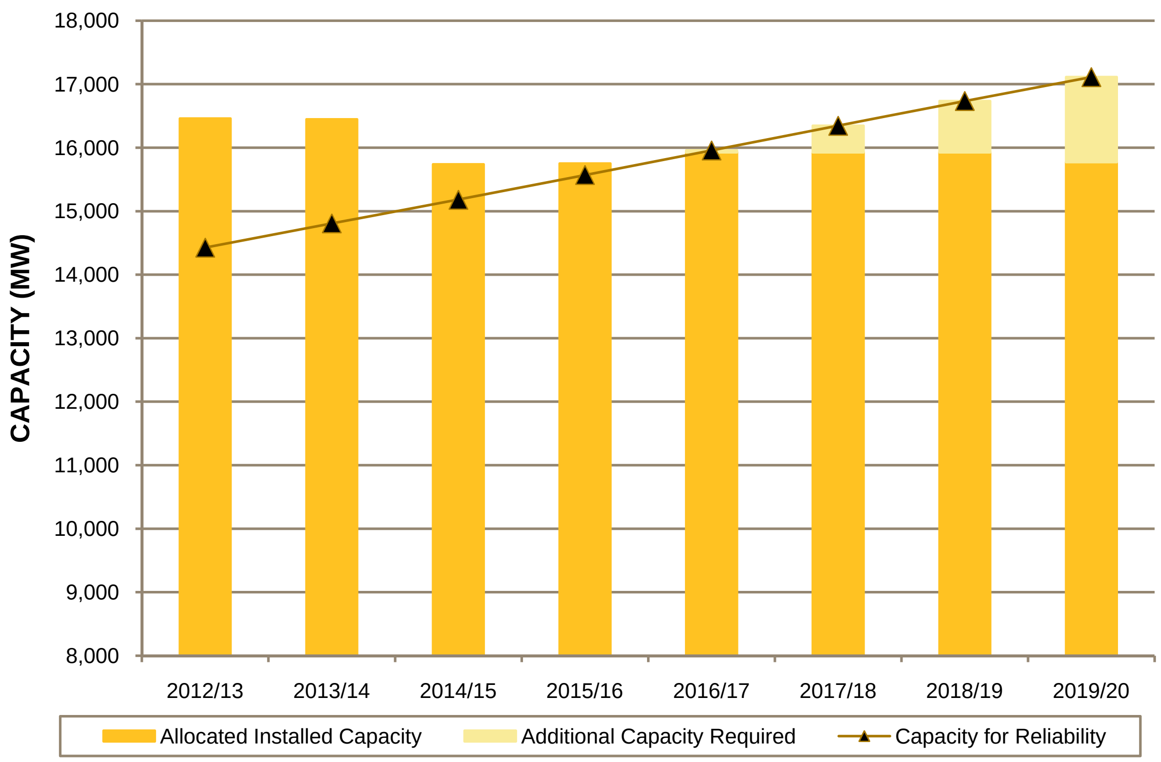


Table 7-4—New South Wales supply-demand outlook summary

Region	Low economic growth		Medium economic growth		High economic growth	
	LRC point	Reserve deficit (MW)	LRC point	Reserve deficit (MW)	LRC point	Reserve deficit (MW)
New South Wales	2017/18	91	**2016/17**	**27**	2016/17	285

7.4.5 Victorian summer outlook

Figure 7-4 presents the projected Victorian summer supply-demand outlook for 2012/13-2019/20.

The figure indicates that, with medium economic growth, Victoria reaches its LRC point in 2015/16, requiring an additional 249 MW of local capacity to delay this shortfall until the following year.

The 2009 ESOO considered Victoria and South Australia as a single region due to the combined structure of their MRL requirements. On this basis, the 2009 ESOO projected a combined LRC point in 2013/14, two years earlier than the new projection for Victoria. The change is primarily due to a reduction in the Victorian MRL, offset by moderate increases in the Victorian MD projections.

Table 7-5 compares the medium economic growth results (shown in Figure 7-4) with the results assuming high and low economic growth (see Chapter 4 for more information about the demand forecast scenarios).

The Victorian LRC point moves forward by one year to 2014/15 with high economic growth. Low economic growth delays the LRC point by two years to 2017/18.

See Attachment 2 for more information about the results from the alternative demand forecast scenarios.

Figure 7-4—Victorian summer supply-demand outlook

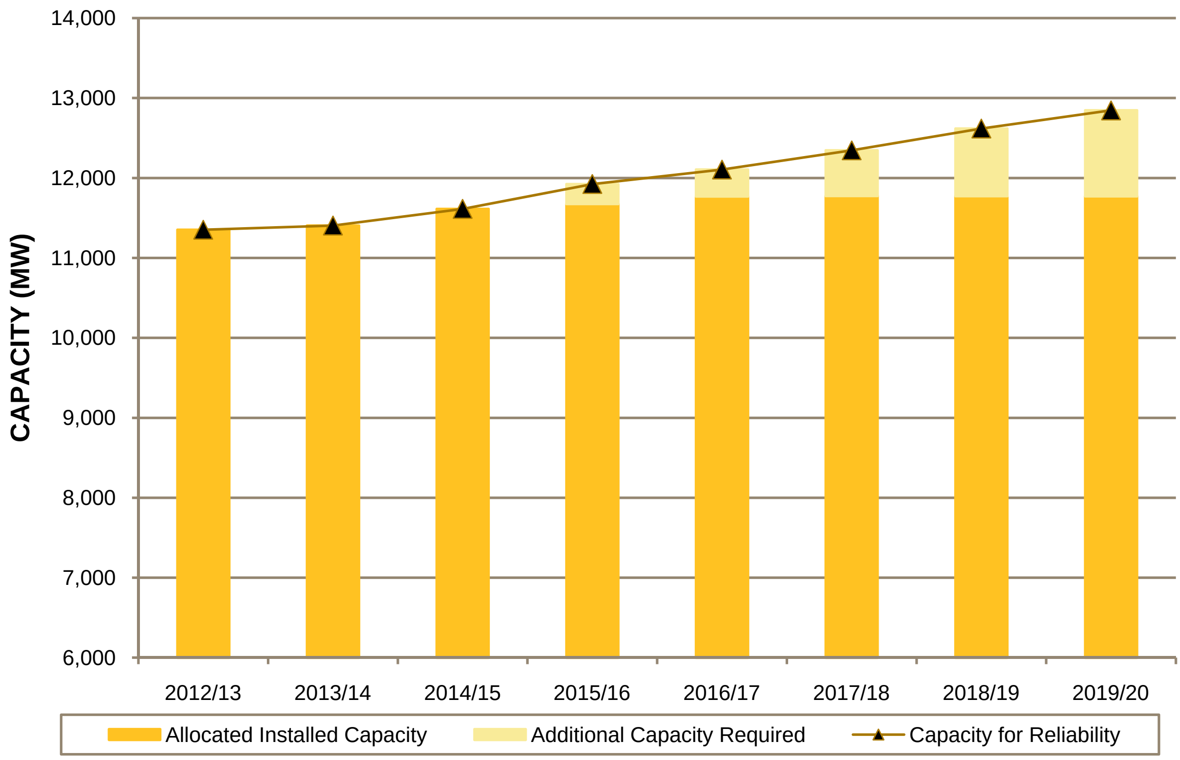


Table 7-5—Victorian supply-demand outlook summary

Region	Low economic growth		Medium economic growth		High economic growth	
	LRC point	Reserve deficit (MW)	LRC point	Reserve deficit (MW)	LRC point	Reserve deficit (MW)
Victoria	2017/18	135	**2015/16** [1]	**249**	2014/15	222

7.4.6 South Australian summer outlook

Figure 7-5 presents the projected South Australian summer supply-demand outlook for 2012/13 to 2019/20.

The figure indicates that, under medium economic growth, South Australia reaches its LRC point in 2015/16, requiring an additional 50 MW of local capacity to delay this shortfall until the following year.

The 2009 ESOO considered Victoria and South Australia as a single region due to the combined structure of their MRL requirements, and implemented an additional local reserve requirement for South Australia. On this basis, the 2009 ESOO projected a South Australian LRC point in 2012/13, three years earlier than the new projection for South Australia. The change is primarily due to a reduction in both the South Australian MD projection and South Australian MRL.

Table 7-6 compares the medium economic growth results (shown in Figure 7-5) with the results assuming high and low economic growth (see Chapter 4 for more information about the demand forecast scenarios).

High economic growth moves the South Australian LRC point forward by three years to 2012/13. Low economic growth delays the LRC point by two years until 2017/18.

See Attachment 2 for more information about the results from the alternative demand forecast scenarios.

Figure 7-5—South Australian summer supply-demand outlook

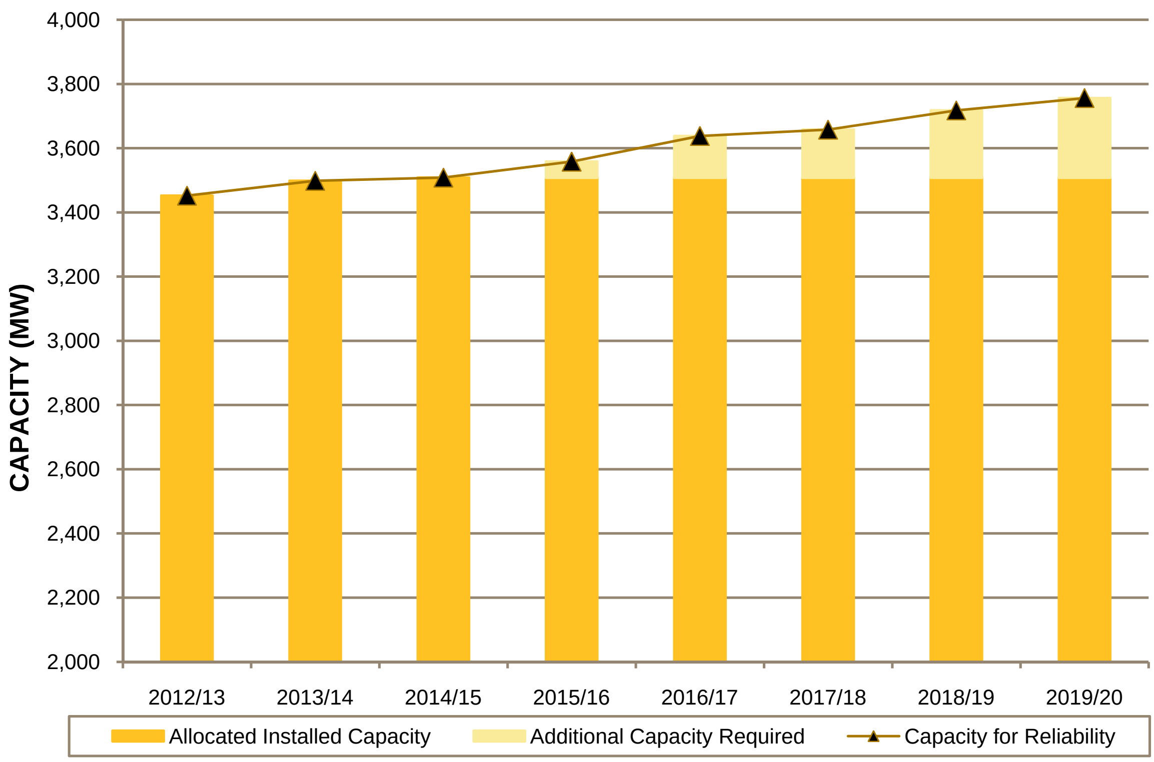


Table 7-6—South Australian supply-demand outlook summary

Region	Low economic growth		Medium economic growth		High economic growth	
	LRC point	Reserve deficit (MW)	LRC point	Reserve deficit (MW)	LRC point	Reserve deficit (MW)
South Australia	2017/18	11	**2015/16**	**50**	2012/13	85

7.4.7 Tasmanian summer and winter outlook

Figure 7-6 presents the projected Tasmanian summer supply-demand outlook for 2012/13-2019/20. As Tasmanian demand peaks in winter, the winter outlook has also been provided in Figure 7-7.

The figures together indicate that, under medium economic growth, no LRC point is forecast for Tasmania within the outlook period. This is consistent with the 2009 ESOO results, which showed the same result.

Table 7-7 compares the medium economic growth results (shown in Figure 7-6) with the results assuming high and low economic growth (see Chapter 4 for more information about the demand forecast scenarios).

There is no Tasmanian LRC point prior to 2019/20 (in summer), and 2020 (in winter) under either of two economic growth sensitivities. See Attachment 2 for more information about the results from the alternative demand forecast scenarios.

The supply-demand outlook only considers capacity adequacy, and cannot indicate a reserve shortfall due to plant energy limitations. This is significant for the Tasmanian region, which principally depends on hydroelectric generation and tends to be energy limited rather than capacity limited. AEMO publishes a quarterly EAAP report that considers unit energy limitations and may provide more relevant information on projected reliability for the Tasmanian region.

Figure 7-6—Tasmanian summer supply-demand outlook

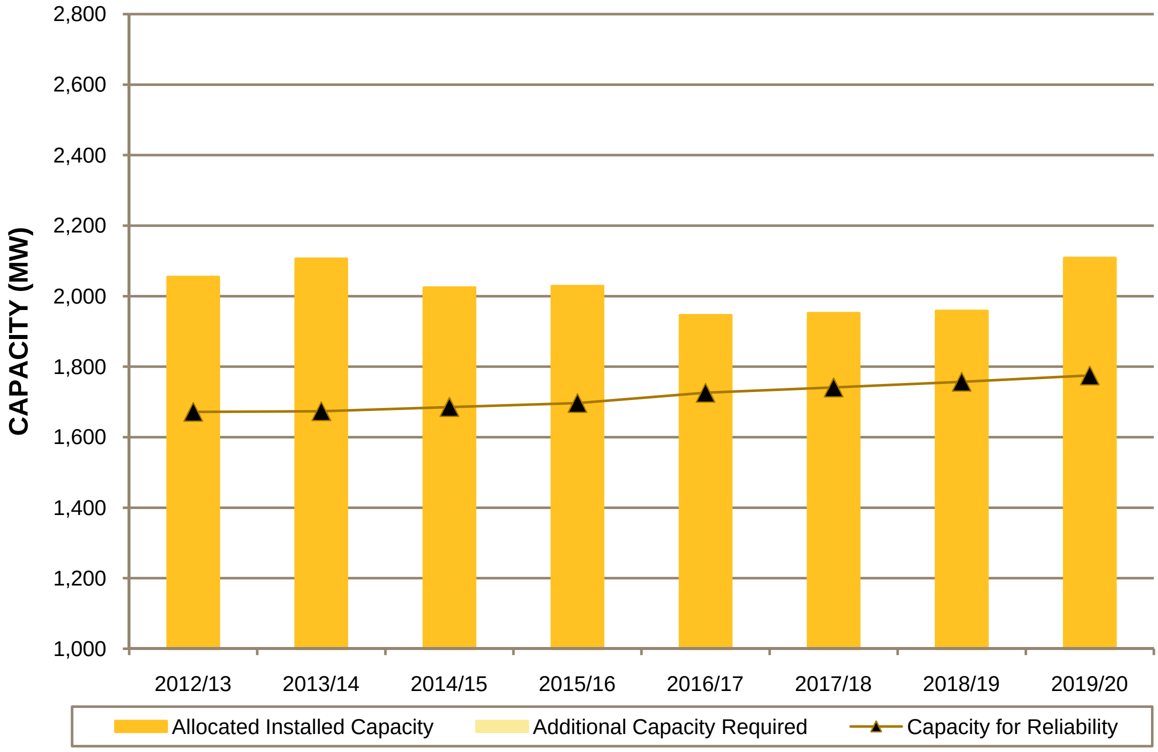


Figure 7-7—Tasmanian winter supply-demand outlook

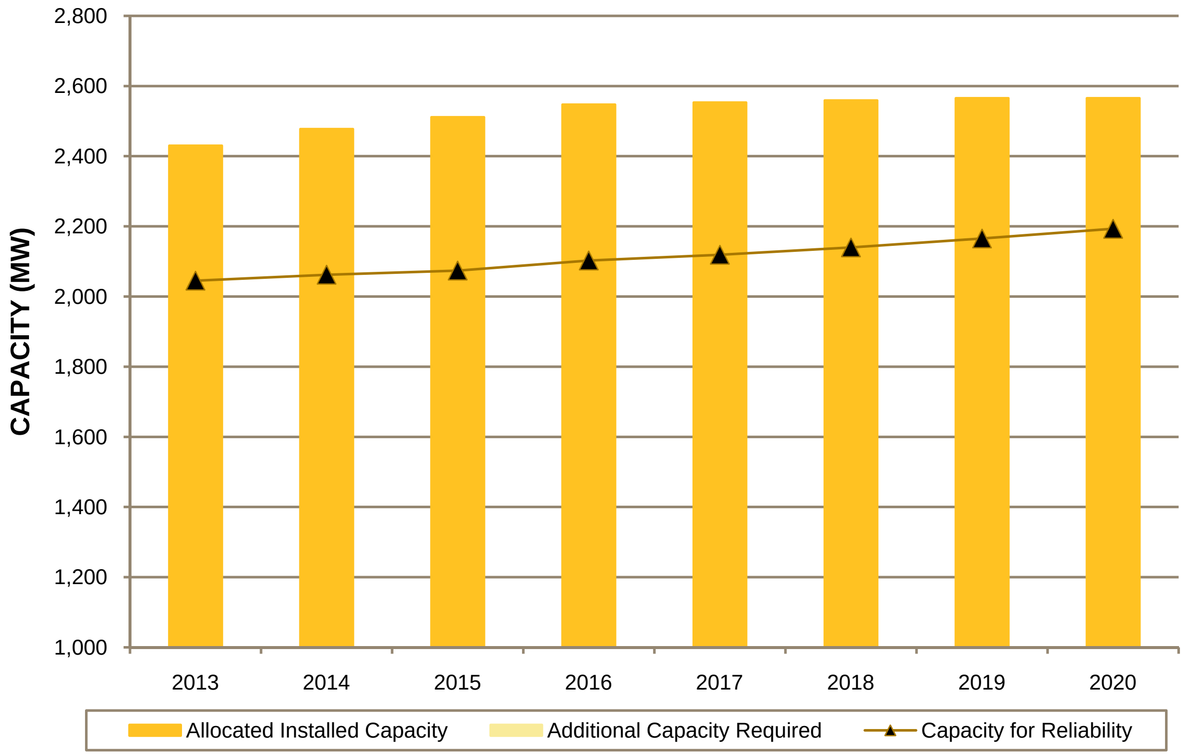


Table 7-7—Tasmanian supply-demand outlook summary

Region	Low economic growth		Medium economic growth		High economic growth	
	LRC point	Reserve deficit (MW)	LRC point	Reserve deficit (MW)	LRC point	Reserve deficit (MW)
Tasmania (summer)	>2019/20	N/A	**>2019/20**	**N/A**	>2019/20	N/A
Tasmania (winter)	>2020	N/A	**>2020**	**N/A**	>2020	N/A

7.5 Summer supply-demand outlook power flows

This section presents the summer supply-demand outlook interconnector power flows and net regional imports. This information provides an indication of the role that interregional support plays in maintaining system reliability.

7.5.1 Interconnector power flows

Table 7-8 lists the interconnector power flows applying to the medium economic growth summer supply-demand outlooks presented in Section 7.4.

Interconnector power flows are limited by network constraint equations, net import limits, and the amount of spare capacity available from each exporting region.

Table 7-8 Summer supply-demand outlook interconnector power flows (MW)

	NSW to QLD		VIC to NSW	VIC to SA		TAS to VIC
Year	**QNI**	**Terranora**	**VIC-NSW**	**Heywood**	**Murraylink**	**Basslink**
2012/13	-95	95	-433	-11	-43	184
2013/14	-101	101	-436	38	-47	268
2014/15	-106	106	-472	63	-63	441
2015/16	-112	112	-645	90	-90	295
2016/17	-119	119	-330	134	-134	610
2017/18	-125	125	-330	163	-163	610
2018/19	-131	131	-352	193	-193	588
2019/20	-137	137	-508	190	-190	432

7.5.2 Net regional import limits

To assess the capacity of a region to meet its MRL, the supply-demand calculator and MT PASA implement net import limits that limit the amount of spare capacity a region can import. The net import limits ensure consistency between the assessment of reserve margins and the calculation of the MRLs. They are only applied to the supply-demand calculator and MT PASA outlook calculations and do not limit actual interconnector power transfers in central dispatch.

Table 7-9 lists the net regional imports applying to the summer supply-demand outlook for each region. Chapter 6 provides more information about net import limits and local MRL requirements.

Table 7-9 Net import limits

	Queensland	New South Wales	Victoria	South Australia	Tasmania
Net import limit (MW)	0[1]	-330	940	0[1]	N/A[2]

1. This region has a local minimum reserve level requirement. This means the region must have sufficient available local scheduled and semi-scheduled generation and local DSP to meet the corresponding 10% POE MD plus its minimum reserve level
2. A net import limit is not applied to Tasmania's reserve margin assessment. Tasmania's minimum reserve level is set at the size of the pre-existing Tasmanian Capacity Reserve Margin, and is independent of any assumed interconnector power

Chapter 8 – Fuel Supply

8.1 Summary

This chapter provides an overview of past and present coal, gas, and liquid fuel supplies, their usage in the National Electricity Market (NEM), and the location and availability of these fuel resources. As coal and gas contribute to over three quarters of electricity generation in the NEM, this chapter focuses on the level and location of coal (black and brown) and gas reserves (conventional, coal seam, and liquefied natural gas).

This chapter also presents information about the use of liquid fuels in the NEM, which currently constitute a small part of the electricity generation mix. Liquid fuels are, however, becoming increasingly important to the NEM for reliability reasons. This is because of their potential to provide back-up for gas-fired generation, which, followed by wind, is already the fastest growing generation technology and is expected to increase as a source of generation if the Australian Government introduces a carbon policy.

8.2 Fuel supply in the NEM

As one of the lowest cost fuels, coal has historically contributed most of the NEM's base load generation. In 2009/10, coal-fired generation provided 81.7%, gas fired generation provided 10%, hydroelectricity provided 6%, and wind generation provided 2%. Other fuel sources, such as liquid fuels, biomass, and solar power, only made minor contributions to the generation mix.

Gas and hydroelectric generation contribute less than one-sixth of energy generation, despite making up almost a third of the available capacity in the NEM. This reflects their usage as fuels for peaking generation, which is sourced largely from open-cycle gas turbine (OCGT), hydro generation and liquid fuels. This accounts for their relative different shares in Figure 8-1, which shows the proportion of total generator capacity by fuel source, and the proportion of generation by fuel source for 2009/10. While coal is the dominant generation technology overall, the dominant fuel for electricity generation varies from region to region. Queensland and New South Wales rely primarily on black coal and Victoria relies on brown coal. Electricity generation in South Australia is largely generated from gas and coal, while Tasmania relies on hydroelectricity.

Figure 8-1—National Electricity Market capacity and generation by fuel source, 2009/10

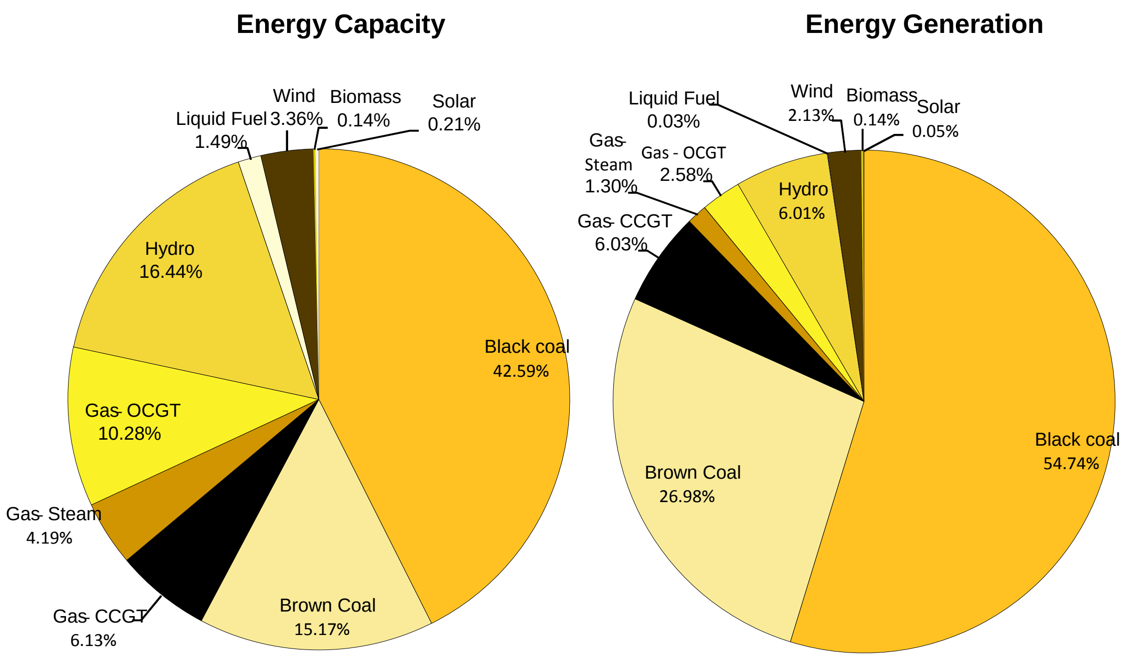
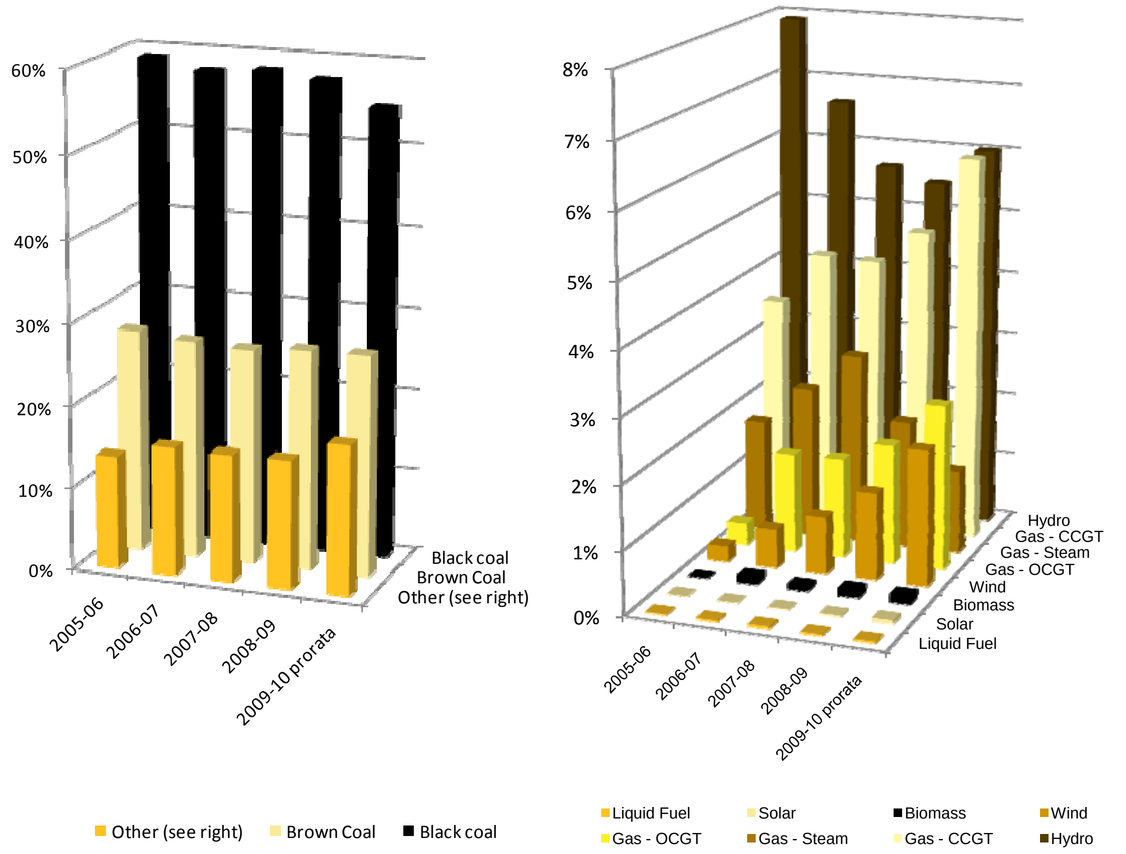


Figure 8-2 shows the change in fuel use for both scheduled and non-scheduled generation over the past five years. While there was a slight drop in the use of black coal in 2009/10 and an increase in the use of other technologies, coal remains the dominant fuel source. Figure 8-2 also indicates a dip in hydroelectric generation during the drought years, followed by a slight recovery in 2009/10 as dam levels began to increase.

Figure 8-2—National Electricity Market fuel use



8.3 Australian coal resources

Australia has abundant coal resources to support its current reliance on coal-fired generation. Use of coal for domestic power generation comprises approximately 15% of coal production. Australia is the largest exporter of coal in the world, and export coal is sourced from black coal mines in Queensland and New South Wales, which both have abundant resources. Based on current production, these coal fields have approximately 100 years of economic black coal reserves.

Victoria has abundant brown coal reserves, and approximately 500 years of current production. Victorian brown coal has generally been used for domestic power production rather than export, because of its low thermal quality and high moisture level. There has, however, been recent discussion about potential for export of Victorian brown coal.

8.3.1 Eastern Australian coal resources

Including sub-economic and inferred coal resources, Eastern Australia has approximately 250 years of black coal resources and over 2,900 years of brown coal resources. Australian coal production has increased at an average annual rate of 3.3% between 2000 and 2008, while domestic consumption has increased at an average annual rate of 1.6% over the same period.

In the latest ABARE projections, which include the national Renewable Energy Target (RET) scheme target and a 5% emissions reduction target, Australia's coal production is projected to increase at an average annual rate of 1.8% between 2007/08 to 2029/30. Over the same period, exports are projected to increase at a rate of 2.4%. Domestic coal consumption is expected to fall at an average annual rate of 0.8%, reflecting a decline in the use of coal for domestic electricity generation.

Table 8-1 lists Eastern Australian coal reserves, showing economic demonstrated resources of over 1 million petajoules (PJ) (approximately 70 billion tonnes), with 70% of these resources located in Queensland and New South Wales.

Table 8-1—Eastern Australian coal resources (PJ)

Basin	Economic demonstrated resources	Sub-economic demonstrated resources	Inferred resources
Queensland			
Bowen	322,118	12,118	253,400
Gallilee	33,328		89,700
Surat	63,758		
Styx		45	
Callide	15,433		
Mulgildie	2,182		
Tarong	25,540		
Ipswich		7,398	
Laura		722	
New South Wales			
Gunnedah	10,518	146	461,300
Sydney	315,502	67,664	286,600
Clarence Morton	40,888	1,132	
Oaklands	22,334		
Gloucester	1,277		
Victoria			
Murray		34,497	148,358
Gippsland	356,919	462,027	740,880
Otway	5,086	8,887	76,698
Moe Swamp			6,748
South Australia			
Arckaringa		63,176	233,400
Leighcreek	415	404	
Polda		4,205	
Nth St Vincent		23,305	9,006
Tasmania			
Tasmania	6,032		
Longford		807	

Source: Geoscience Australia and ABARE. Australian Energy Resource Assessment (2010)

8.3.2 Coal resources by region

Queensland

Queensland has approximately 56% of Australia's economic demonstrated resources of black coal. Ten coal-fired power stations operate in Queensland. The Tarong, Kogan Creek, and Millmerran Power Stations are mine-mouth operations supplied from their own mines. The Callide and Collinsville Power Stations are mine-mouth operations supplied by captive independent mines. Stanwell Power Station is supplied by coal transported by rail from a captive independent mine. The only power stations relying on non-captive independent mines are Swanbank B (which has announced that it will be retired), and Gladstone, which has a long-term contract with Rolleston.

Apart from the mine supplying the Collinsville Power Station (medium life), all the mines have long expected lives.

New South Wales

New South Wales has approximately 40% of Australia's economic demonstrated resources of black coal. Eight coal-fired power stations operate in New South Wales, in the Newcastle, Hunter, and Western coal fields. The Hunter power stations have long-term coal supply agreements, with 80% of the coal for the Newcastle and Western region power stations being supplied by Centennial Coal. Prices are due for re-negotiation from 2012, which may be influenced by higher export prices.

Victoria

Victoria has almost all of Australia's economic demonstrated resources of brown coal. There are five privately owned, mine mouth coal-fired power stations in the La Trobe Valley, which all have ample reserves for many years. Victorian brown coal has a much higher moisture content than black coal (50-60% higher) and a lower ash and heating value (7-11 MJ/kg). While there has been limited export in the past, there is potential for export where moisture can be removed.

South Australia

South Australia has more limited coal resources than the other regions, with the main production field located at Leigh Creek. Leigh Creek coal is of a lower quality than New South Wales or Queensland black coal, but a higher quality than Victorian brown coal. The main and upper seams at Leigh Creek can be mined until 2017 or 2018. Alinta, the mine operator, recently began mining the lower seams, which may extend the mine's life by up to 10 years. Alinta has also considered that railing coal from the Western coal fields in New South Wales may be viable, possibly mixed with lower quality Leigh Creek coal to create a blend that is suitable for use in the purpose-built boilers.

South Australia has other coal resources, though these are generally low quality or remote from existing generation. There have been some proposals to develop coal mines in the Arckaringa Basin, Clinton, and Kingston to satisfy a number of competitive options such as export, gasification, coal-to-liquids, or combined generation and mining projects.

Tasmania

Tasmania has black coal deposits in the Tasmania Basin and brown coal deposits in the Longford Basin. However, almost all power generation in Tasmania is supplied by hydroelectricity and gas. There is only one coal mining company in Tasmania, Cornwall Coal, which primarily supplies the cement plant at Railton as well as most of Tasmania's general coal requirements.

8.4 Australian gas resources

In recent years, there has been a noticeable increase in gas exports and the use of gas as a source of electricity generation. Increased gas-fired generation has driven an increase in gas consumption of 4% per year over the past decade. In 2009,180 PJ of gas was used for power generation in the NEM, equalling 28% of total gas production. This increase in consumption is expected to continue if an Australian carbon policy is introduced. The increased consumption and demand for gas exports is driving technological innovation, demonstrated through the emergence of coal seam gas (CSG).

8.4.1 Eastern Australian gas resources

There are six major gas-producing basins in Eastern Australia, both conventional and CSG:

- The Surat and Bowen basins west of Brisbane produce conventional gas and growing volumes of CSG.
- The Cooper Basin in North-East South Australia and South-West Queensland.
- The Gippsland, Otway, and Bass basins off Victoria, all of which produce conventional gas.

Gas production patterns are changing, with falling production from the Cooper Basin, rising Queensland CSG production, and significant production from the Otway and Bass basin substituting for Gippsland production. New South Wales and South Australia both rely on Victoria for approximately half their gas requirements, and Queensland is now exporting CSG to the southern states.

Australia appears to have sufficient gas reserves and resources to meet both export and domestic demand beyond 2030. Eastern Australia has just over 100,000 PJ of gas reserves and resources (3P plus 2C)[51], or 160 times the current level of production. CSG comprises three-quarters of 2P reserves and nearly 80% of total gas reserves and resources. The growth in CSG reserves partly reflects improved technology but it also reflects assumptions of achieving higher gas prices through exports. The volume of CSG reserves is relatively price elastic.

There are also substantial offshore Victorian reserves and resources totalling 10,800 PJ, or 30 times the current level of Victorian production. In 2009, Eastern Australian gas production was 653 PJ, having grown by 83 PJ since 2004, at an average annual growth rate of 2.7%.

Table 8-2 lists information about conventional and CSG gas reserves in the regions.

Table 8-2—Eastern Australian economic gas resources, as at 1 January 2009 (PJ)

Basin	Region	Conventional	CSG	Total
Bowen-Surat	Queensland	477	15,714	16,191
Cooper	South Australia/Queensland	911	0	911
Gunnedah	New South Wales	12	336	348
Clarence-Morton	New South Wales	0	298	298
Gloucester	New South Wales	0	176	176
Sydney	New South Wales	0	67	67

[51] Based on the Society of Petroleum Engineers (SPE) classification of reserves.

Basin	Region	Conventional	CSG	Total
Gippsland	Victoria	8,641	0	8,641
Otway	Victoria	1,889	0	1,889
Bass	Victoria	528	0	528
Total	-	12,458	16,591	29,049

Source: Geoscience Australia. Conventional gas includes economic and sub-economic resources. CSG only includes economic demonstrated resources

In the longer term, the cost of imported gas is likely to increase in real terms due to higher development costs in Victoria and higher CSG prices in Queensland. At higher prices, additional Cooper Basin resources are likely to become economic.

Coal seam gas

Australia's identified CSG resources have grown significantly in recent years. From 2003-2008, further CSG exploration led to an increase in 2P reserves of approximately 46% annually. The drive to access CSG resources in Australia has been fuelled by improvements in extraction technology and the corresponding success in producing CSG from low rank coals in the United States, and recently in Queensland.

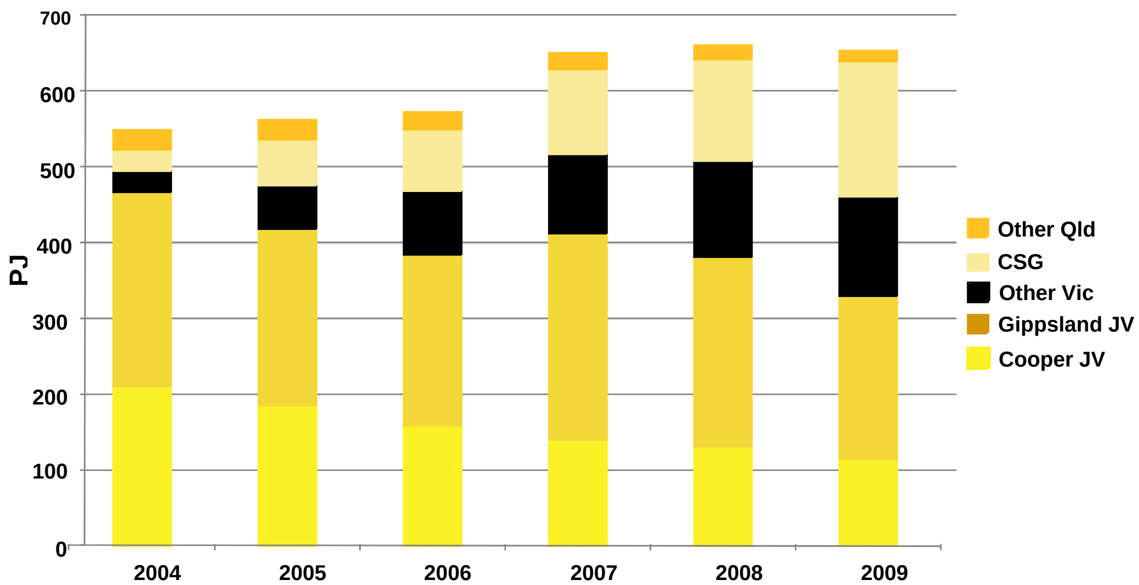
These successes have also stimulated exploration for CSG in South Australia, Tasmania, Victoria, and Western Australia. CSG exploration in Australia is still relatively immature and the current high levels of exploration are expected to add to known resources.

Reserve life is more than 100 years at current rates of production. In 2008, CSG accounted for approximately 12% of the total gas economic demonstrated resources in Australia.

Gas production

The pattern of gas production for Eastern Australia is changing, with declining output from the Cooper Basin fields due to natural field decline, growing CSG in Queensland, and the substitution of gas from the Otway and Bass Basins for gas from Gippsland, reflecting market dynamics. Figure 8-3 shows this changing patter over the years 2004-2009.

Figure 8-3—Eastern Australian gas production, 2004-2009



Source: EnergyQuest

While New South Wales and South Australia historically relied on gas from the Cooper Basin, both regions sourced approximately half their gas from Victoria in 2009. Queensland is meeting its own gas needs, predominantly from CSG, and is now exporting gas to the southern States through the South West Queensland Pipeline and QSN Link. There are also plans to export LNG.

New South Wales only produces modest volumes of gas, but there are growing reserves in the Gunnedah and Clarence-Morton Basins in the region's north, the Gloucester Basin near Newcastle, and the Sydney Basin.

Gas consumption

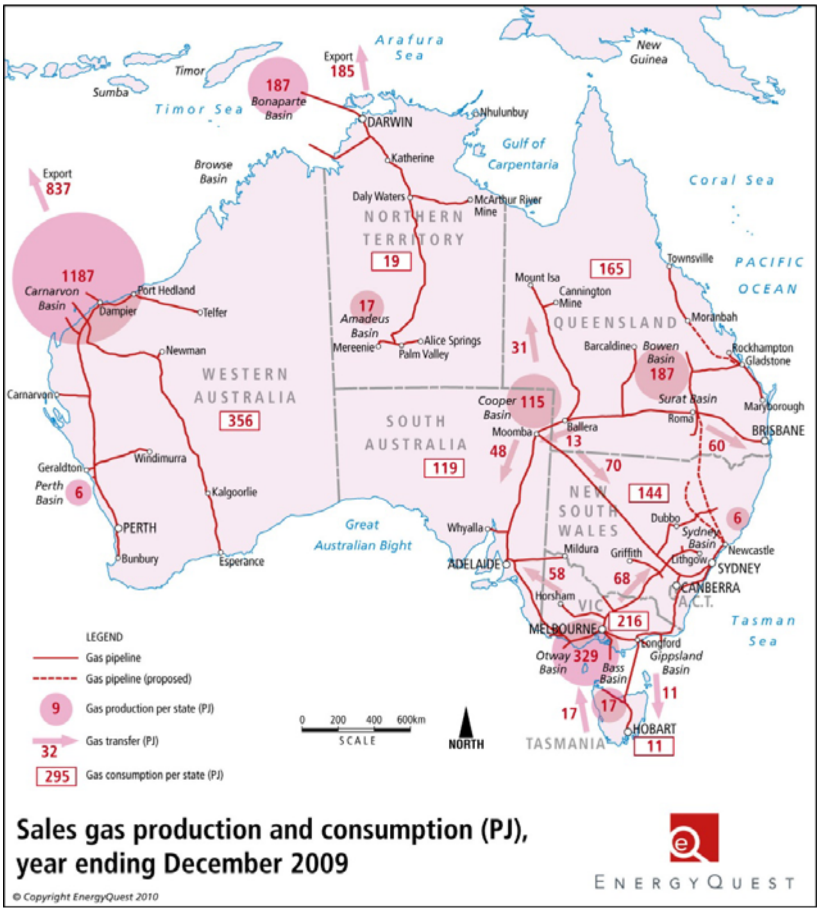
The level of gas consumption varies across regions, as does the proportion of gas used for power generation relative to other uses. Victoria is the largest gas-consuming region, using 216 PJ in 2009. Gas use in Victoria has been growing at an average rate of 1.6% per annum over the last five years, and is largely driven by manufacturing and residential demand. Victoria is a relatively small user of gas for gas-fired generation, consuming approximately 20 PJ in 2009. Gas use for gas-fired generation peaked at 38.3 PJ during the drought of 2007, but has since fallen.

Queensland is the second largest gas-consuming region, using 165 PJ in 2009. The major uses of gas are for gas-fired generation (60.7 PJ in 2009), manufacturing (mainly minerals processing), and mining. In 2009, gas use for gas-fired generation increased with the start-up of the Braemar 2, Condamine, and Darling Downs Power Stations. Gas use in Queensland has been growing at an average rate of 7.6% per annum over the last five years, largely due to increased gas use for gas-fired generation.

New South Wales is the third largest gas consuming region, using 144 PJ in 2009, 30.2 PJ of which was used for gas-fired generation. The major use of gas is for manufacturing. After being relatively flat, gas use in New South Wales grew strongly in 2009 with the commencement of new gas-fired generation. South Australia uses a relatively large amount of gas for gas-fired generation. Of the total 119 PJ of gas consumed in 2009, 61.9 PJ were used for gas-fired generation. Tasmania consumed 11 PJ in 2009, with 7.1 PJ used for gas-fired generation.

Figure 8-4 shows the gas production and consumption in Australia during 2009.

Figure 8-4—Sales gas production and consumption 2009 (PJ)

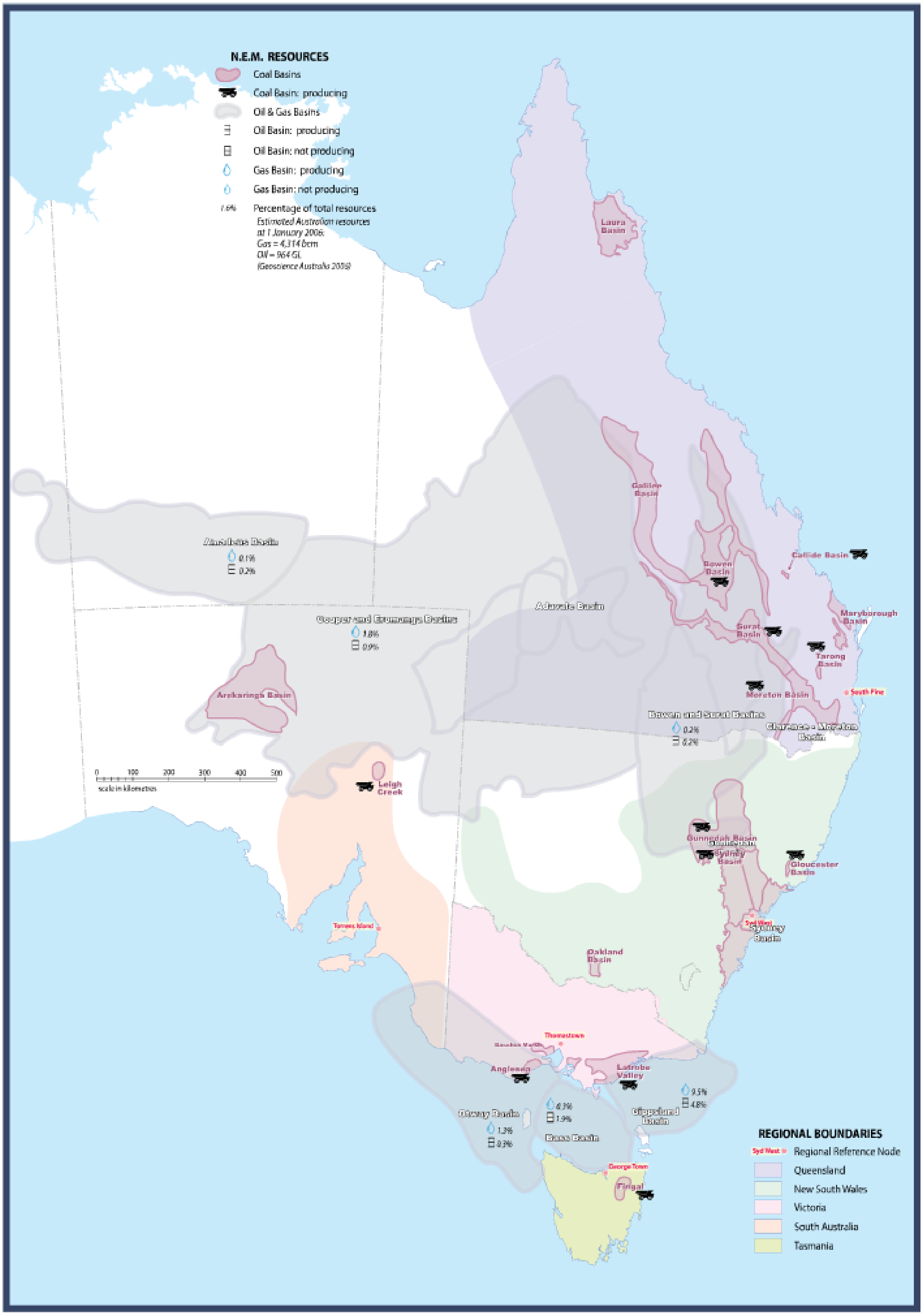


Source: EnergyQuest

8.5 Sources and reserves

Figure 8-5 shows the location of coal, gas, and oil resources throughout the regions.

Figure 8-5—Fossil fuel resources in Eastern Australia



8.6 Liquid fuels

Liquid fuels are used to generate electricity while also playing an important role as a back-up fuel for gas-fired generation. Back-up fuel options will become increasingly important for reliability as the dependence on gas-fired generation increases.

The key liquid fuels used for oil-based power generation are diesel, fuel oil, recycled oils, and kerosene. As these fuels are costlier than coal or natural gas, generators designed to run solely on liquid fuels are limited to peak or emergency generation[52], or remote power generation due to the lower cost of providing fuel transport infrastructure.

Coal plants use auxiliary fuels for start-up and shutdown, or for temporarily maintaining flame stability when changing output. Auxiliary fuels may be natural gas, fuel oil, or recycled oil. Many natural gas plants also use a liquid fuel for back-up when gas supply is restricted. In some cases, rather than using liquid fuels, gas pipe 'looping' is used to provide some on-site line-pack to manage short-term gas supply interruptions.

Gas supplies to generators are commonly curtailed for short periods during gas demand peaks, but also during very rare extreme events such as the 1998 Longford disaster. NEM CCGT plants do not have back-up fuels.

Alternative fuels such as LPG and condensate are not mainstream fuels and are historically higher cost alternatives to gas and coal. Biodiesel is not currently seen as a reliable substitute for diesel, mainly due to limited reliability among suppliers and concerns over quality and fuel stability.

8.7 Policy linkages

A number of policy developments have the potential to affect fuel supply and its usage in the NEM. These include the introduction of a national RET scheme and the possible introduction of an Australian carbon policy (see Chapter 2 for more information). Other policy developments that may impact fuel supply include:

- investment in coal-fired generation in Queensland
- the development of a Short-Term Trading Market (STTM) for gas, and
- consideration of a resource rent tax.

Queensland Government coal-fired generation investment policy

In 2009, as part of its climate change strategy, the Queensland Government announced that no new coal-fired power station will be approved in Queensland unless the plant:

- uses world's best practice low emission technology in order to achieve the lowest possible levels of emissions, and
- is carbon capture and storage-ready (CCS) and will retrofit that technology within five years of CCS being proven on a commercial scale.

[52] A generator with the principal function of providing system restart capability.

Policies of this type are expected to result in increased investment in gas-fired generation.

The Short-Term Trading Market

AEMO has been developing a gas Short-Term Trading Market (STTM) as part of the Ministerial Council on Energy's energy market reform agenda. The STTM is designed to provide a market-based wholesale gas-balancing mechanism to facilitate the trading of gas between pipelines, participants, and production centres. Sydney and Adelaide gas hubs will be operational on 1 September 2010, with the Brisbane hub expected to be operational by 1 September 2011. It is expected that the STTM will also expand to include the Australian Capital Territory and potentially regional demand centres.

The existing retail gas markets in South Australia, New South Wales, and Queensland will continue to operate in conjunction with the STTM wholesale gas market in each region, while the Victorian wholesale gas market will continue to run in parallel with the emerging national gas market.

The STTM is expected to encourage the development of new transportation products on pipelines, and will also provide an alternative channel for retailers, gas-fired generators, and end-users to buy or sell gas.

Resource rent tax

The Australian Government has announced its intention to introduce a tax on company profits in the mining industry. The exact policy design and its application are under consideration.

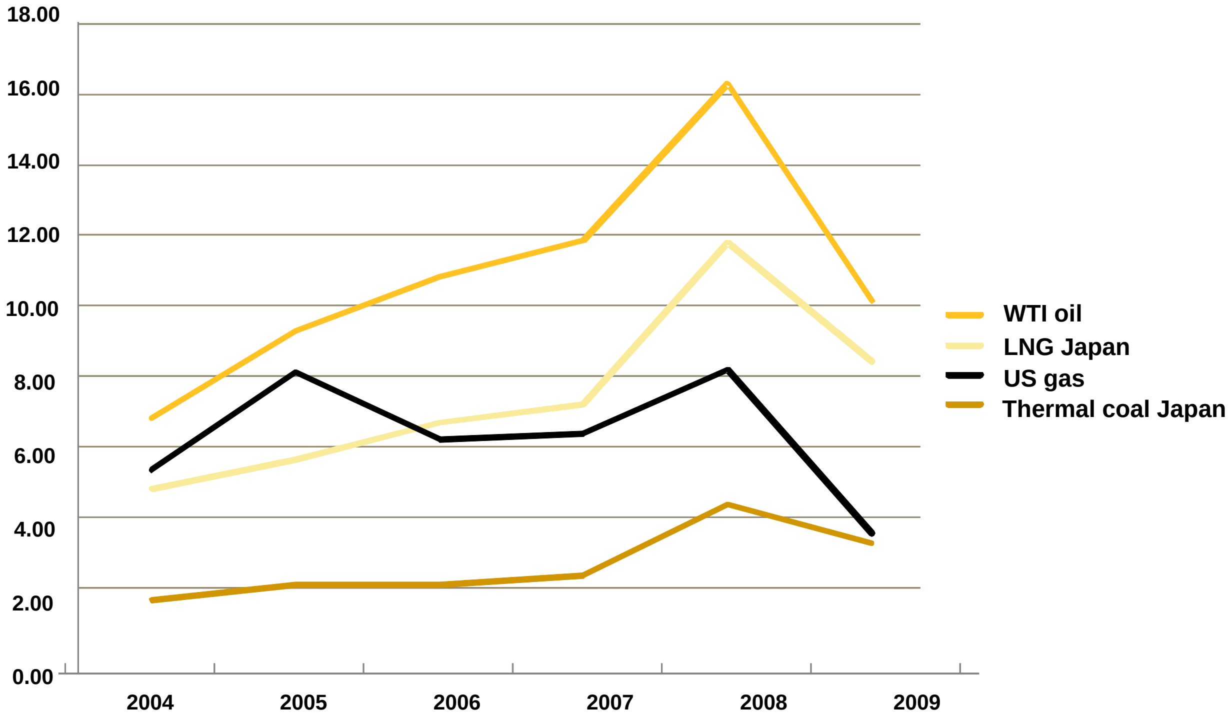
8.8 Fuel prices

Relative fuel costs are an important determinant of fuel use. Oil is the most expensive fuel on an energy basis, while coal is the cheapest. Australia has generally benefited from the availability of low-cost fossil fuels. In some cases, the use of those fuels, or fuels from some sites, has been limited to domestic use. Others are internationally traded, or in the case of gas, will be in the near future. In the long term, international fossil fuel prices are expected to increase as a result of growing demand. Figure 8-6 shows international fuel prices for oil (WTI[53]), LNG imported into Japan, US gas (Henry Hub), and thermal coal imported into Japan.

Gas imported as LNG into Northern Asia is indexed to oil prices and is relatively expensive. US gas prices (a global gas price benchmark) fell heavily in 2009 due to the recession and the increase in US gas production.

[53] West Texas Intermediate (WTI) is a type of crude oil used as a benchmark in oil pricing and is the underlying commodity of the New York Mercantile Exchange's oil futures contracts. The refined product used for generation would be more expensive.

Figure 8-6—International fuel prices, 2004-2009 (US$/GJ)



Sources: BP, US Energy Information Administration

Coal prices

Coal costs vary across the NEM depending on the type of coal, quality, its location in relation to the power station, and the nature of the arrangements under which it is supplied. In many cases, coal deposits are owned by the generator, making it difficult to estimate costs. These are often referred to as captive mines and usually produce coal at relatively low and stable costs. Often this coal is not suitable for export or the mine is not located with infrastructure to support efficient export. In cases where coal is purchased from third parties, prices are generally confidential. The prices for supply of export grade coal are often below International prices in these cases, however, because they are purchased on long-term contracts. Overall, coal is generally the cheapest fuel source in the NEM, ranging from below A$0.50 per gigajoule (GJ) in Victoria to between A$1.00 and A$2.00/GJ in New South Wales, Queensland, and South Australia.

Exports of thermal coal are sold both under long-term contracts (approximately 70%) and on a spot basis (approximately 30%). Spot prices for export ex-Newcastle as of February 2010 were US$93.25 per tonne, or approximately A$3.90/GJ. Growth in international markets is driving this higher price. As a result, there is now some pressure from the export market on coal prices for domestic power generation. This is likely to be most evident in Queensland and New South Wales as long-term contracts expire and need renegotiation.

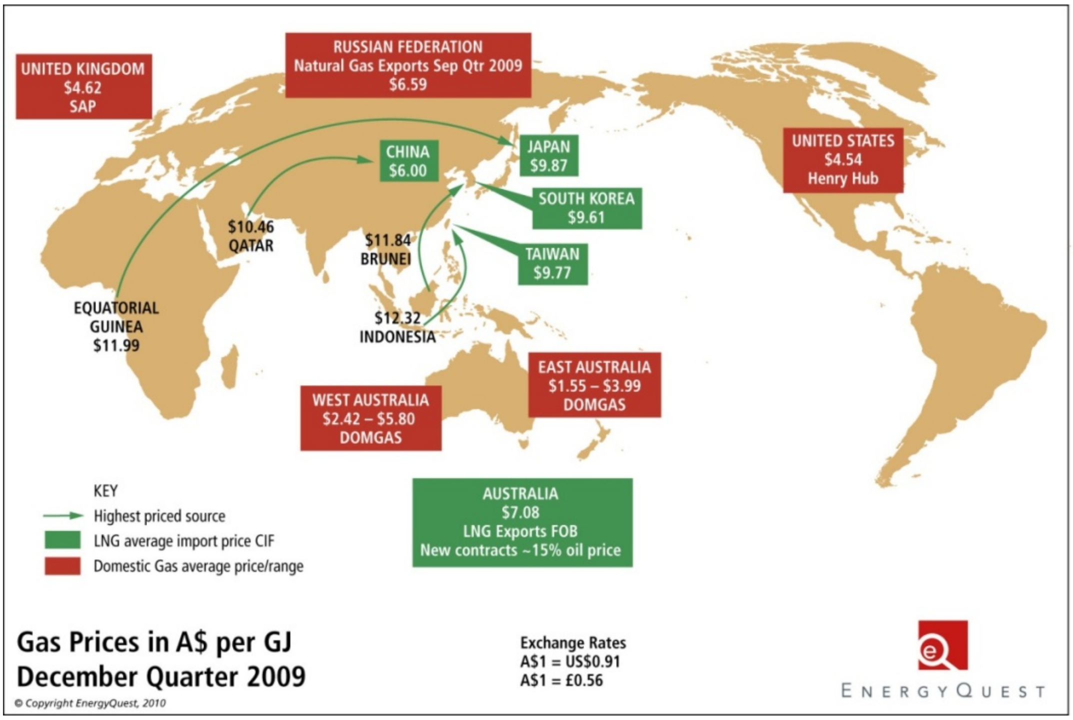
Gas prices

As with coal, there continue to be disparities between domestic gas prices and export prices. Figure 8-7 shows international and Australian gas prices in A$/GJ for the 2009 December quarter. The international figures include the UK system average price (SAP), US Henry Hub spot gas price, the average export price for gas (predominantly pipeline gas) from Russia, and the average landed import prices (CIF) (green boxes) for LNG into Japan, Korea, Taiwan, and China.

The arrows show the highest average price imports into each country in the December quarter. The figure also shows the average price for Australian LNG exports in the December quarter compared with domestic gas prices (ex-field).

International prices continue to be higher than Australian domestic prices, giving rise to concerns that Eastern Australian gas prices may ultimately rise. It is worth noting that domestic fuel purchases for power generation are generally considered lower risk, due to the ability to make longer-term volume contracts, a low currency risk, and potentially lower transport costs.

Figure 8-7—International gas prices



Source: EnergyQuest

Attachment 1- Economic Outlook and Government Policies

A1.1 Summary

This attachment summarises assumptions about future macroeconomic developments, government policy, consumer choice, and technological developments that informed the energy and maximum demand projections and the supply-demand outlook.

AEMO has used three different economic growth scenarios (medium, low, and high) over a 10-year outlook period. KPMG prepared these forecasts, which are presented in the Stage 1[54], Stage 2[55], and Stage 3[56] Reports. This attachment focuses on the Stage 1 and Stage 2 Reports, including:

- future energy policy and market trends, and
- economic forecasts for the Australian states and territories.

This attachment also provides a description of the national economic forecasts used to develop the projections, and an outline of the current government policy agenda and emerging energy market trends. Significant developments the projections have incorporated include:

- average national population growth of between 1.0% and 1.7% per annum, and national economic growth of between 2.1% and 3.4% per annum
- the introduction of carbon pricing in 2013/14, with prices increasing to support emissions reductions targets of either 5%, 15%, or 25% by 2020
- increasing replacement of conventional electric storage hot water systems with solar hot water, increasing penetration of small-scale, roof-top photovoltaic generation, and projections of up to 20% of Australia's electricity generation based on renewable sources by 2020, and
- above-trend increases in energy efficiency, offset to some extent by new spot loads, including water desalination plants, and the adoption of plug-in electric vehicles.

A1.1.1 Significant policy changes

The Australian Government announced further delays to its proposed emissions trading scheme in April 2010. Legislation for the scheme has now been abandoned until after the 2010 Federal election. The implementation of either the currently proposed emissions trading scheme or some other effective price on carbon emissions is unlikely to be implemented before 2013/14.

Trading under the national RET scheme has been divided into arrangements for small projects (including eligible hot water and small roof-top photovoltaic systems) and for large projects (such as wind farms). See also Chapter 2, Section 2.3.2, for more information about this trading division. The

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[54] KPMG. Key Energy Policies and Economic Drivers - Stage 1 Report, March. Report to AEMO. April 2010.

[55] KPMG. Stage 2 Report – Economic Scenarios and Forecasts 2009/10 to 2029/30. Report to AEMO. April 2010.

[56] KPMG. Stage 3 – Semi-Scheduled, Non-Scheduled and Exempted Generation By Fuel Source 209/10 to 2019/30. Report to AEMO. April 2010.

objective of this change is to ensure that a fixed proportion of Australia's future energy is generated from large-scale renewable systems, and that potentially worthwhile renewable electricity generation projects are not crowded out by the installation of small hot water and roof-top solar systems.

A1.1.2 Significant changes to the economic outlook

The economic downturn in 2009/10 was milder and recovery from the Global Financial Crisis (GFC) faster than expected at this time last year. The current Federal Treasury estimate of Australian gross domestic product (GDP) growth for 2009/10 is +2.0%, compared with -0.5% at the same time last year[57]. KPMG's latest medium economic growth forecast for the next five years averages 3.1% per annum, compared with 2.8% per annum at the same time last year.

A1.2 Energy policies and market trends

A1.2.1 Background and summary

A number of current and prospective Australian and State or Territory Government initiatives and independent market trends may significantly impact energy markets within the next 10 years. However, the implementation details and potential impact of many of these developments are uncertain. The surveyed energy policies and market trends were identified in KPMG's Stage 1 Report in March 2010, and have been used as the common basis for the preparation of the projections. In particular, they have been:

- used in the development of KPMG's April economic and non-scheduled generation forecasts (Stage 2 and Stage 3 Reports), and
- considered (along with other relevant information) by AEMO and the jurisdictional planning bodies (JPBs) when developing their energy and maximum demand projections.

Table A.1-1 summarises the policy schemes and market trends identified by KPMG. The individual impacts of these schemes may overlap to some extent, and the extent to which a business-as-usual forecast should be adjusted to account for them is complex to assess. See Section A1.2.4 for further analysis of the likely impacts on the projections.

The regional energy and maximum demand projections were developed on the assumption that the emissions trading scheme described in Table A.1-1 is implemented in 2013/14, reflecting the Australian Government's decision not to reintroduce the associated Carbon Pollution Reduction Scheme (CPRS) legislation before the 2010 Federal election.

Table A.1-1–Likely impacts of energy policies and market trends on electricity demand

Description	Assumed timing	Estimated impact on energy demand	Likelihood
Emissions trading (CPRS) with alternative reduction targets of 15%, 25% and 5% by 2020 for the medium, high, and low growth forecasts, respectively	July 2011 (since delayed to 2013/14)	Modelling commissioned by Federal Treasury in 2008 estimated that, with an emissions reduction target of 5% by 2020: wholesale electricity prices would increase 56%, and electricity consumption would fall 12%,	Highly unlikely to be implemented, with the earliest implementation time in 2013, following the 2010 Federal election. Emissions trading or an equivalent carbon tax will have

57 Commonwealth of Australia. Budget Measures 2010-11. Budget Paper No.1, Statement 2. May 2010. Available at http://www.budget.gov.au/

Description	Assumed timing	Estimated impact on energy demand	Likelihood
		compared to no emissions reduction target	the most substantial impact on electricity demand (as well as supply) and will likely dwarf the impacts of any other measures
National Renewable Energy Target (RET) scheme – the latest version includes separate targets of 41,000 GWh for large-scale renewable electricity generation and an overall target of 45,000 GWh, with the difference expected to be made up by small-scale projects, mainly solar hot water heaters and roof-top photovoltaic panels	August 2009	Modelling commissioned by Federal Treasury in 2008 estimated a minimal impact on wholesale and retail prices for the original scheme. The major impact will be on the proportion of underlying electricity demand that is supplied from renewable sources, and identified as semi-scheduled, non-scheduled, or as an offset to demand measured at transmission nodes	Policy has been implemented. A split in the national RET scheme was introduced in early 2010 in an attempt to alleviate uncertainty in relation to the price of renewable energy certificates, which reduced potential investment in large scale technologies
Feed-in tariffs, mainly for small-scale photovoltaic generation	2009	Maximum known potential supply subject to these arrangements are as follows: Queensland – 0.2% by 2014 New South Wales – 0.6% by 2017 Victoria – 2.0% by 2025 South Australia – 0.7% by 2028	Differing schemes in each state or territory have already been implemented, with the exception of Tasmania and Western Australia, where a net feed-in tariff was due to be introduced in July 2010
National Framework for Energy Efficiency – greenhouse-intensive water heater phase out	2010-2012	Expected reduction of between 1% and 2.4% of Australian electricity consumption from 2008 levels	Highly likely to be implemented
National Framework for Energy Efficiency – Minimum Energy Performance Standards (MEPS) and labelling standards for refrigerators, freezers and air-conditioners	2010	Expected annual average reductions in Australian electricity consumption: refrigerators – 50 GWh or 0.02% freezers – 4 GWh or 0.00% air-conditioners – 300 GWh or 0.15%	Policy implemented this year
Victorian Energy Efficiency Target	July 2009	Measures that convert to a target of 4.5% of Victoria's 2008 electricity consumption by 2011	Policy has already been implemented
New South Wales Energy Savings Scheme	July 2009	Measures that target a reduction of 8,500 GWh between 2009 and 2012	Policy has already been implemented
South Australian Residential Energy Efficiency Scheme	January 2009	Targets convert to around 2% of South Australian electricity consumption per annum, based on 2008 levels	Policy has already been implemented
Renewable Energy Bonus Scheme – ceiling insulation, solar and heat pump hot-water rebates	February 2010	The insulation rebate, now discontinued, is unlikely to have significantly reduced energy usage, because experience suggests that the benefits of improved insulation are normally enjoyed almost exclusively as higher comfort levels	The policy was implemented and the insulation component has since been withdrawn and changes made to other scheme components following criticism of the entire scheme's management and effectiveness
Renewable Energy Bonus Scheme - Green Loans	February 2010	Estimated total energy savings of 609 GWh compared with 2008 consumption levels by July 2014	Policy has been implemented and was amended (see Renewable Energy Bonus Scheme – ceiling insulation, solar and heat pump hot-water rebates). Uncertainty surrounding impacts
Incandescent light bulbs	February 2009	Expected savings of approximately 1.1% per annum of Australia's 2008 energy consumption levels. Maximum demand impact in winter will be significant in some regions	Policy has already been implemented
Water desalination plants	Current	Expected operating pattern will result in increased electricity consumption as the following percentages of each region's 2008 levels: Queensland – 0.5%	Plants have recently been commissioned or are under construction to service five major regions

Description	Assumed timing	Estimated impact on energy demand	Likelihood
		New South Wales – 0.6% Victoria – 1.7% South Australia – 3.9% Tasmania – not applicable Western Australia – 2.2%	
Plug-in electric vehicles	2012 onwards	Mass-produced plug-in electric vehicles capable of being charged from the grid will become widely available in Australia by 2012. The charging infrastructure is already being privately planned. Electric vehicle charging has the potential to significantly increase electricity usage, particularly during off-peak periods when 'smart charging' may be used to take advantage of low energy prices. However, future sales of electric vehicles are obviously highly speculative	It is likely that there will be some take-up of electric vehicles over the next 10 years, but the extent remains highly uncertain

A1.2.2 Assumed government policies

Key elements of policy, especially the proposed emissions trading regime, are uncertain and the details of their eventual implementation are likely to vary from initial proposals.

Emissions trading

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

The Australian Government introduced legislation for a national emissions trading scheme (the CPRS) in early 2009. This proposed scheme has since been abandoned pending the outcome of the 2010 Federal election. Therefore, for the purpose of developing the regional energy and maximum demand projections, AEMO and the JPBs have assumed similar price trajectories and emissions targets to those described in Table A.1-1, but with an implementation date of 2013/14.

The CPRS was the principal means by which the Australian Government sought to fulfil Australia's greenhouse gas reduction targets. Assuming a similar regime or carbon tax equivalent was to start in 2013/14, then this delay has a negligible impact on energy and maximum demand over a 10-year timeframe. In the first year of its previously intended operation, from June 2011 to June 2012, the low initial ceiling price will be unlikely to significantly affect electricity prices. Along with the abandonment of the CPRS, there is also a partly offsetting policy emphasis on increasing energy efficiency. The forecasts of non-scheduled generation are also relatively insensitive to the timing of an emissions trading scheme, since those forecasts are primarily based on the incentives provided by the RET.

Renewable Energy Target

The national RET scheme was implemented by the Australian Government in 2010. It increases the mandatory target for renewable energy production from the previous target of 9,500 GWh in 2010 to a total 45,000 GWh in 2020 (estimated to be 20% of electricity supply). The national RET scheme absorbs or replaces previously existing State and Territory targets. The scheme operates by issuing Renewable Energy Certificates (RECs) for units of energy produced from eligible renewable sources. RECs are then purchased by energy retailers who are required to surrender certificates each year in order to meet their target obligation for that year.

The current scheme includes a solar credits multiplier and a split target to address previous concerns about the declining price of RECs and the large proportion of RECs being created by small-scale renewable technologies at the possible expense of large projects. The solar credits multiplier provides additional incentives for the development of small-scale technologies, by providing a large rebate for eligible installations and creating ‘phantom’ RECs that are not backed by an equivalent generation capacity. The April 2010 modifications to the scheme consisted of dividing it into a separate target of 41,000 GWh by 2020 for large-scale renewable technologies and an overall unchanged target of 45,000 GWh, with the difference expected to be met or exceeded by small-scale technologies.

To meet the new target, it is assumed that a considerable increase will take place in both:

- small renewable energy units of less than 1 MW capacity (including roof-top PV systems) and solar hot water systems
- non-scheduled renewable generating units with a capacity of 1 MW or greater exporting into a local electricity network, and
- semi-scheduled intermittent generating units (particularly wind farms).

Feed-in tariffs

Feed-in tariffs provide a premium for operators of small generating units, as well as roof-top, solar hot water systems that provide power back to the grid, or otherwise reduce the grid requirement. South Australia was the first Australian State to introduce a feed-in tariff for renewable generating units of less than 10 kW. Other States and Territories have since either implemented or proposed feed-in tariffs of some type.

Domestic water heating

The Australian Government continues to provide a rebate (currently through the Renewable Energy Bonus Scheme) for the replacement of existing electric storage hot water systems with solar or heat pump systems. The means tested rebate of $1,000 ($600 for heat pumps) is available for eligible privately owned homes. This replaces the similar previous Solar Hot Water Rebate Program.

Most Australian State Governments are phasing out household electric storage hot water heaters, either by proscribing further new installations, or through building standards that require stringent energy and water efficiency measures.

Energy efficiency initiatives

The National Framework for Energy Efficiency (NFEE) emanates from the Ministerial Council on Energy (MCE). Stage 1 of NFEE has been implemented, and comprises building efficiency standards, opportunities for energy efficiency in industry, information provision and training, and Minimum Efficiency Performance (MEPS) standards for electrical appliances.

Stage 2 of the NFEE continues and expands Stage 1 activities to include:

- strengthening and expanding MEPS
- phasing out incandescent light bulbs
- Australian Government green loans
- a heating, ventilation, and air-conditioning (HVAC) efficiency strategy, and

- a national water heater strategy.

In parallel with national initiatives, a number of State Government energy efficiency schemes have either commenced or are about to commence. These include the Victorian Energy Efficiency Target (VEET), the proposed New South Wales Energy Savings Scheme (ESS) and the South Australian Residential Efficiency Standard (REET).

A1.2.3 Energy market trends

Water desalination plants are one example of a significant energy-intensive investment that may be separately considered by AEMO and the JPBs when developing the regional energy and maximum demand projections. See Chapter 3 for specific details of major new loads that have been taken into account.

Technological change over the next 20 years is likely to have significant impacts on both the demand and supply side of the electricity industry. The adoption of rechargeable, plug-in electric vehicles is one example of a new technology with the potential to significantly increase electricity consumption. However, the number of plug-in electric vehicles on the road at the end of the ESOO projection period remains highly uncertain.

Other developments to be considered include the Victorian and national roll-outs of advanced metering (smart meters), which have the potential to provide energy consumers with a price signal at the time of consumption. This has the potential to significantly alter consumers' response to short-term price signals.

A1.2.4 Impacts on the ESOO

Emissions trading

The growth scenarios AEMO and the JPBs used to develop the energy and maximum demand projections account for the economic costs of introducing the CPRS as it was proposed in early 2010, as well as the direct electricity and gas price impacts.

The abandonment of attempts to push through the legislative changes required for an emissions trading scheme will result in a minor delayed energy price impact, compared to KPMG's price forecasts.

The 2009 ESOO also considered the introduction of an emissions trading scheme. Table A.1-2 lists the differences between the 2009 and 2010 KPMG electricity price forecasts. The 2010 price forecasts were produced on the basis that the CPRS would be introduced in July 2011, so are likely to be marginally too high for the 2011/12 year.

Table A.1-2—NEM Retail Electricity Prices, Medium Growth Forecasts

Region	2009 ESOO	2010 ESOO	Change
	c/kWh average 2010/11 to 2019/20		
Queensland	14.97	16.39	+1.42 (+9.1%)
New South Wales	13.60	13.66	+0.06 (0.4%)
Victoria	16.84	16.07	-0.77 (-4.7%)
South Australia	20.05	18.27	-1.78 (-9.3%)
Tasmania	13.55	13.64	+0.09 (+0.7%)

Compared to the 2009 electricity price forecasts, the 2010 forecasts are on average:

- higher in Queensland
- lower in South Australia, and
- relatively unchanged in other regions.

The changes are due to changes in the underlying macroeconomic drivers, a re-estimation of historical prices for the period 2004-2009 (for which there is incomplete actual data), and the changed emissions trading scheme assumptions, compared to last year. The new price forecasts may be expected to have a small but significant independent downward impact on energy demand in Queensland and an upward impact on energy demand in South Australia.

Renewable energy, solar hot water and feed-in tariffs

Due to the definitions adopted by the JPBs when preparing their energy and MD projections:

- energy and MD supplied from generating units of less than 1 MW is observed and forecast as energy efficiency, and
- energy and MD supplied from all other generating units is allocated to either non-scheduled, semi-scheduled, or scheduled generating units.

The RET does not alter the underlying demand for electricity, but does drive changes in the sources of supply for projected energy and maximum demand and the mix of scheduled, semi-scheduled and non-scheduled generating units and energy efficiency.

Direct solar hot water subsidies further lower the installation costs (above the value of the RECs created) in eligible circumstances. Feed-in tariffs may also substantially reduce the pay-back period for the installation of roof-top photovoltaic or other small generating systems.

Energy efficiency

Recent trends in energy efficiency are implicit in historical energy and MD data and are therefore continued in the projections. Uncertainty surrounds the extent to which new policies should be explicitly accounted for in the energy and MD projections because of uncertainty over:

- what constitutes a genuine new trend in energy efficiency, rather than the means for continuation of existing trends
- the details of future policies, their implementation date and the extent of their application, and
- the extent to which genuine new energy savings will translate into lower energy use, rather than additional energy use at no extra cost, due to the ‘rebound effect’ (the phenomenon whereby consumers enjoy at least part of the lower cost of energy services by using more of them).

AEMO and the JPBs have generally made some allowances in their energy and maximum demand projections for increased above-trend energy efficiency as a result of measures including:

- accelerated installation of solar hot water and roof-top photovoltaic systems
- tightened building and appliance efficiency standards
- the phase-out of incandescent light bulbs
- State energy efficiency targets
- subsidised home insulation, and
- the roll-out of interval metering.

The specific efficiency adjustments to the energy and MD projections made by the JPBs are generally similar to the adjustments that were made for the 2009 ESOO. For more information, see Table A.1-1.

Other Developments

The widespread adoption of plug-in electric vehicles is likely to impact energy consumption within the next 10 years. The widespread adoption of such technology, however, is less likely to require new generation capacity to support it, but rather is likely to make increased use of existing capacity at off-peak times of the day.

A1.3 Economic Forecasts

A1.3.1 Medium, high, and low growth scenarios

The economic forecasts underlying the ESOO projections are based on the conceptual framework for economic and energy market scenarios developed jointly by AEMO, the Department of Resources, Energy and Tourism (DRET) and an industry Stakeholder Reference Group (SRG)[58,59] (the AEMO/DRET scenarios). The AEMO/DRET scenarios provide a consistent framework for analysis underlying a number of AEMO and DRET publications and are distinguished from one another by:

- underlying demand growth, largely driven by population and economic growth
- centralised supply responses to global demand and carbon policies, including large-scale, capital-intensive electricity generation and long distance transmission infrastructure, and
- decentralised supply responses to global demand and carbon policies, including smart grid technology with real-time pricing, small-scale distributed generation, combined heat and power (CHP), and renewable electricity generation.

AEMO engaged KPMG to provide demographic, macroeconomic, and sectoral forecasts consistent with the AEMO/DRET scenarios to use as inputs for the development of the regional energy and maximum demand projections. In order to develop the scenarios' demand-side, KPMG focussed on the economy-wide aspects to arrive at three sets of economic growth forecasts (medium, high, and low) based on three broad factors:

- The strength of global economic growth and the resultant demand for Australian commodity exports and transfer of the benefits of technological innovation.
- The strength of Australian population growth.
- The assumed CO2-equivalent emissions targets and related carbon price trajectories associated with an emissions trading scheme (although the original KPMG assumptions were modified slightly to reflect the recently announced deferral of this scheme).

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[58] The SRG was made up of industry experts with a diverse range of experiences and interests. The input of the group after several discussions was synthesised into a report by McLennan Magasanik Associates. This report was approved by the SRG and has been accepted by AEMO and DRET as a common strategic framework for long term energy modelling.

[59] McLennan Magasanik Associates. Future Developments in the Stationary Energy Sector: Scenarios for the Stationary Energy Sector 2030. Report to AEMO/DRET. October 2009.

Table A.1-3 lists a summary of KPMG's medium, high, and low economic growth assumptions and their alignment with the DRET/AEMO scenario. The table shows that the key input assumptions underlying the medium, high, and low growth forecasts relate to:

- world economic growth, commodity prices, and productivity growth
- migration and fertility, and
- emissions targets and carbon price trajectory.

Table A.1-3 Description of KPMG's medium, high, and low scenario drivers

	KPMG medium growth (representation of AEMO/DRET scenario 3)	KPMG high growth (representation of AEMO/DRET scenario 1)	KPMG low growth (representation of AEMO/DRET scenario 5)
Global economy	Sustained solid global growth: • assumed global growth of 1.15% in 2009/10 • assumed global growth of 3.24% throughout rest of forecast, and • broadly in line with IMF forecast of 3.9% in 2009/10 Base case assumption of global recovery from the Global Financial Crisis Commodity prices, exchange rates, and oil prices are all moderate: • based on RBA index of rural and non-rural commodity prices • non-rural commodity prices increase by 5.5% in 2010/11 • rural commodity prices increase by 5.5% in 2010/11, and • long run assumption of 2% growth thereafter Moderation of world credit-risk premiums Increased capital liquidity Technology innovation to support baseline productivity growth: • assumed productivity growth of 1.5% in each industry	Strong growth in China and India: • assumed global growth of 5.1% from 2010/11 onwards Strong global recovery from Global Financial Crisis High commodity prices, high exchange rate, but moderate oil prices: • non-rural commodity prices increase by 9.5% in 2010/11 • rural commodity prices increase by 9.5% in 2010/11, and • long run assumption of 2% growth thereafter World credit-risk premiums below medium growth scenario High level of capital liquidity Technology innovation to support high productivity growth: • strong investment in Research and Development, and • assumed productivity growth of 1.75% in each industry	Weak global growth: • assumed global growth of 2.5% from 2010/11 onwards Slow global recovery from Global Financial Crisis Low commodity prices, low exchange rate, but moderate oil prices: • non-rural commodity prices increase by 3.4% in 2010/11 • rural commodity prices increase by 3.4% in 2010/11, and • long run assumption of 2% growth thereafter World credit risk premiums above medium scenario Low level of capital liquidity Low labour force skills result in slow productivity growth: • assumed productivity growth of 1.25% in each industry
Demographic projections	Moderate immigration: • assumed net overseas migration of 189,000 per annum in the long run Moderate population growth: • assumed long run fertility rate of 1.93%	High immigration: • assumed net overseas migration of 249,000 per annum in the long run High population growth: • assumed long run fertility rate of 1.96% • based on a 2007/08 fertility rate	Low immigration: • assumed net overseas migration of 129,000 per annum in the long run High population growth: • assumed long run fertility rate of 1.73% • based on a 2001/02 fertility rate

	KPMG medium growth (representation of AEMO/DRET scenario 3)	KPMG high growth (representation of AEMO/DRET scenario 1)	KPMG low growth (representation of AEMO/DRET scenario 5)
Carbon price/emission targets assumptions [60]	CPRS – 15: • moderate emission reduction targets in Australia and internationally, and • assumes an emissions reduction target of 15% by 2020 Carbon prices: • $10/t CO2-e for 2011/12 • %34.3/t CO2-e in 2012/13, and • carbon price grows by real rate of 4% per annum from 2012/13 onwards	CPRS-25%: • international agreement of strong emissions reduction targets, and • assumes an emissions reduction target of 25% by 2020 Carbon prices: • $10/t CO2-e for 2011/12 • %51.4/t CO2-e in 2012/13, and • carbon price grows by real rate of 4% per annum from 2012/13 onwards	CPRS-5%: • low emission targets agreed internationally, and • assumes an emissions reduction target of 5% by 2020 Carbon prices: • $10/t CO2-e for 2011/12 • $24.6/t CO2-e in 2012/13, and • carbon price grows by real rate of 4% per annum from 2012/13 onwards

A1.3.2 Methodology and data sources

KPMG developed the medium, high, and low growth forecasts for each State and Territory using the MM2 (Murphy Model 2)[61] suite of three linked demographic, macroeconomic, and sectoral and States models. The key features of these models are:

- modelling of a forward-looking financial sector, with Keynesian (demand-driven) dynamic short-term behaviour and Neoclassical (supply-driven) optimisation behaviour in the long run
- the ability to produce quarter-by-quarter 29-year forecasts, and
- use of publically available sources of data and a transparent approach to model development.

KPMG have also developed a series of separate equations, linked to the main MM2 model outputs, which were used to produce electricity and gas retail prices, sub-sectoral output and energy demand forecasts.

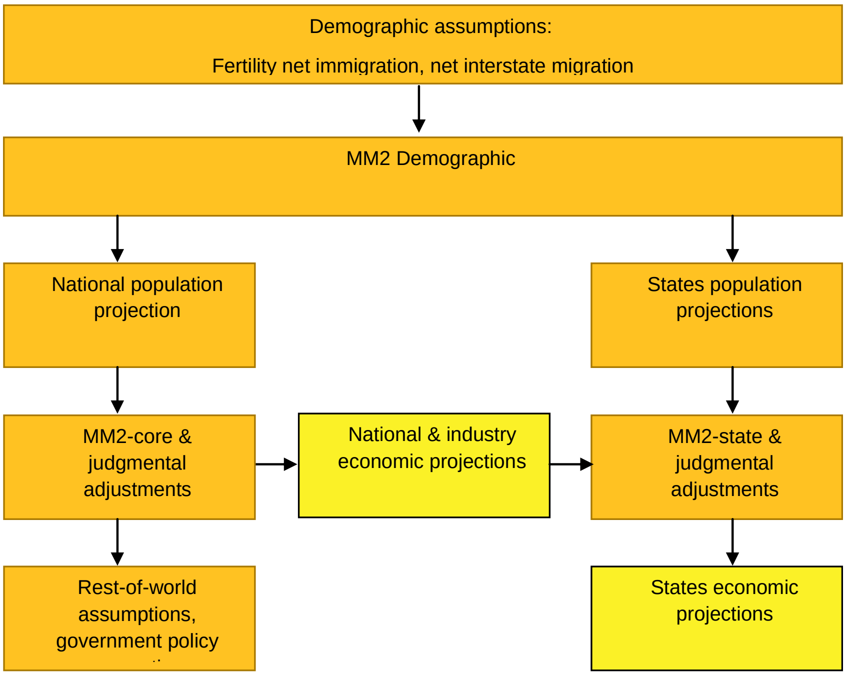
Figure A.1-1 shows the inter-relationships between KPMG's main three models. The core component of MM2 produces forecasts of national macroeconomic variables and national 18-industry forecasts. The MM2-States model produces State and Territory macro forecasts. Population projections from the MM2-demographic model are an input to both the macroeconomic and States models. The Residual Allocation System or RAS method[62] is used outside of this modelling system to split the national industry forecasts into State-level industry forecasts.

[60] As proposed by KPMG, the carbon price/target assumptions are based on Treasury (2008), Australia's Low Pollution Future: the Economics of Climate Change Mitigation – Summary, page VIII. KPMG modified these price/target assumptions to reflect implementation delays expected in March 2010 and price inflation. AEMO now expects a further delay in implementation, following the announcement in April 2010 of a deferral of the scheme until after the 2010 Federal election.

[61] MM2 was developed by Chris Murphy and the original structure is described in detail in: Powell A.A. and C.W. Murphy (1997), Inside a Modern Macroeconomic Model – A Guide to the Murphy Model, Springer, Berlin, 2nd Ed.

[62] The RAS method involves the iterative manipulation of a matrix of components where each row and column total is known. See: ABS Occasional Paper: The RAS Method for Compiling Input-Output Tables: ABS Experience.

Figure A.1-1—Linkages between the MM2 suite of models[63]



The impact of carbon pricing was incorporated into the economic forecasts by using the results of previous KPMG analysis conducted with a multi-product (600+) computable general equilibrium model (MM600+). This model was used to examine the long-run effects of carbon pricing on the wider economy, including its effects on the price and demand for electricity and gas. MM2 accounts for the economy-wide impacts of carbon pricing by 'taxing' the Electricity, Gas and Water industry at an appropriate rate, while the carbon price components of KPMG's separate electricity and gas retail price forecasts are used to scale up each of the business-as-usual modelled components.

A1.3.3 Energy demand and economic activity

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

The primary drivers of electricity consumption are distinct over the short and long term. In the very short term, the impacts of weather and habitual behaviour predominate over any long-run growth trend. Over time, however, the number and mix of electrical appliances adapts to sustained changes in economic activity, electricity prices, and technologies, which drives the nature of longer-run growth.

Historical trends may be altered by the introduction of energy-specific policies. As a result, the ESOO energy and maximum demand projections are not determined entirely on the basis of the economic outlook, despite its substantial long-term impact.

Electricity prices and consumption are negatively correlated. The impact, however, of a change in electricity prices:

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[63] Reproduced from KPMG Stage 2 Report, p35.

- has historically been relatively weak, due to the sunk (unrecoverable) costs of electrical equipment and the generally low proportion of electricity cost in a typical consumer's budget, and
- depends on the relative price of available substitute energy sources.

The increasing use of domestic time-of-use metering and charging helps create demand response opportunities, which may change the aggregate responsiveness of electricity demand to price changes.

A1.3.4 International economic outlook

Developments in the global economy have a strong impact on Australia's growth prospects. As a resource-based economy, external demand for commodities has a significant and direct impact on Australian export earnings. The availability of credit from overseas also dictates the cost of funding within the Australian financial sector.

Since late 2009, the global economy has exhibited signs of recovery, and economic conditions have improved more rapidly than previously expected. Growth is being driven primarily by growth in developing countries, particularly in Australia's Asian trading partners. Meanwhile developed countries are likely to continue to experience more sluggish growth rates.

KPMG's medium growth forecast assumes a continued recovery in global economic growth, with high risk premiums and reduced capital liquidity returning to normal levels during 2010/11. Renewed economic activity flows through to increased demand and prices for Australian commodities.

The high growth forecast assumes a somewhat stronger recovery in global economic growth, compared to the medium growth forecast, led by strong growth in China and India. Growth in this forecast is aided by lower risk premiums, increased capital liquidity, and higher commodity prices than in the medium growth forecast.

Conversely, the low growth forecast assumes a slow global recovery from the Global Financial Crisis, with continued weakness in developed economies and a slower industrial production in developing countries, compared with the medium growth forecast. Growth in the low growth scenario is hindered by continued tightness in credit markets, lingering risk aversion, low levels of capital liquidity, and relatively weak commodity prices.

A1.3.5 National economic outlook

In addition to the external drivers, labour force growth, and adequate investment, the Australian economy's long-run growth is significantly determined by productivity growth. KPMG's medium growth forecast assumes that technological innovation supports long-run productivity growth of 1.50% per annum. This rate is in accordance with the Commonwealth Government's 2009/10 Budget assumptions[64], but slightly below the 30-year historical average assumed by the Treasury in the 2010 Intergenerational Report[65]. The high forecast is based on a long-run assumption of average productivity growth of 1.75% per annum, while the low growth forecast assumes a slower rate of 1.25% per annum.

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[64] Commonwealth of Australia. Budget Strategy and Outlook 2009-10. Budget Paper No.1, Statement 2. May 2009. Available from http://www.budget.gov.au/2009-10/

[65] Commonwealth of Australia. The Intergenerational Report 2010. 2010. Available from http://www.treasury.gov.au/igr/igr2010/

From a moderation in economic growth during 2008/09 due to the effects of the Global Financial Crisis, the Australian economy is currently picking up, with a fully fledged recovery expected to take place in 2010/11. Under each of the medium, high, and low KPMG growth forecasts, the major determinants of growth will be export volumes and prices, the residential construction sector, and private consumption. The different assumptions underlying each forecast have a cumulative effect, so that the divergence between the high, medium, and low growth forecasts becomes more pronounced over the medium to long term. Table A.1-4 lists a range of indicators for the next 10 years for the medium, high, and low growth forecasts. Average GDP growth for the medium, high, and low growth forecasts is 2.69%, 3.37%, and 2.08% per annum, respectively.

Table A.1-4—Australian medium, high, and low economic growth forecasts

Medium	Population '000s	Gross Domestic Product 2006/07 $m	Consumer Price Index 1989/90=100	Standard Mortgage Rate % p.a.	Terms of Trade Index 2006/07=100
2008/09 actual	21,730	1,095,264	166.4	9.45	113.4
2009/10	22,100	1,120,788	169.2	5.80	107.5
2010/11	22,440	1,165,149	172.1	6.90	107.3
2011/12	22,767	1,207,187	176.3	6.13	105.8
2012/13	23,087	1,239,796	180.4	5.80	105.2
2013/14	23,409	1,279,859	183.9	5.61	105.0
2014/15	23,740	1,325,649	187.3	5.65	105.0
2015/16	24,081	1,366,403	191.6	5.90	105.2
2016/17	24,423	1,397,804	197.2	6.23	105.6
2017/18	24,766	1,423,102	203.3	6.51	106.0
2018/19	25,110	1,448,902	209.3	6.66	106.3
2019/20	25,455	1,479,886	214.5	6.69	106.6
Avg forecast growth % p.a.	1.41	2.69	2.48	-0.34	-0.07

High	Population	Gross Domestic Product	Consumer Price Index	Standard Mortgage Rate	Terms of Trade Index
2009/10	22,105	1,121,574	169.1	5.80	109.9
2010/11	22,461	1,166,879	171.2	6.67	113.5
2011/12	22,823	1,212,278	173.4	5.53	112.8
2012/13	23,189	1,247,441	175.5	4.97	112.7
2013/14	23,569	1,294,041	176.7	4.64	112.9
2014/15	23,969	1,352,257	177.6	4.59	113.3
2015/16	24,380	1,406,927	179.7	4.82	113.7
2016/17	24,794	1,450,631	183.3	5.17	114.2
2017/18	25,210	1,484,084	187.5	5.48	114.8
2018/19	25,629	1,522,806	191.2	5.64	115.3
2019/20	26,050	1,572,408	194.0	5.66	115.6
Avg forecast growth % p.a.	1.66	3.37	1.40	-1.81	0.21

Low	Population	Gross Domestic Product	Consumer Price Index	Standard Mortgage Rate	Terms of Trade Index
2009/10	22,069	1,119,165	169.0	5.80	105.8
2010/11	22,369	1,159,224	171.9	6.88	103.3
2011/12	22,634	1,198,149	176.8	6.04	101.4
2012/13	22,881	1,232,253	182.1	5.70	100.7
2013/14	23,119	1,270,164	187.5	5.63	100.6
2014/15	23,355	1,307,131	193.7	5.88	100.7
2015/16	23,598	1,333,264	201.3	6.34	101.1
2016/17	23,841	1,347,550	209.9	6.83	101.8
2017/18	24,084	1,356,408	218.4	7.19	102.4
2018/19	24,326	1,370,980	225.9	7.35	103.0
2019/20	24,567	1,394,709	232.4	7.36	103.4
Avg forecast growth % p.a.	1.05	2.08	3.40	0.75	0.00

A1.3.6 State and Territory economic outlook

Queensland

As a mining-dependent State, Queensland was hard hit by the downturn in commodity demand and prices in 2008/09. At the same time, consumer spending was weak and dwelling investment contracted. However, the immediate outlook is more optimistic as export earnings and consumption growth recovers. Mining will continue to be a driver of growth in the medium term, although dependence on the mining sector will make Queensland a strongly cyclical economy. Strong mining activity will also be supported by an expansion of coal seam methane production. Over the longer term, Queensland farming is expected to outperform the wider national agricultural industry due to global demand for ethanol fuel produced from sugar cane. Figure A.1-4 shows historical and forecast medium, high, and low gross state product (GSP) growth.

New South Wales (including the Australian Capital Territory)

The New South Wales economy has benefitted recently from the effect of fiscal stimulus measures on consumption and the contribution of low interest rates to the housing expansion. New South Wales is heavily reliant on the services sector, which is forecast to expand strongly in the medium term. The services sector is also relatively insensitive to the introduction of carbon pricing, and the prospects for New South Wales are relatively bright. Figure A.1-2 shows historical and forecast medium, high, and low GSP growth.

Victoria

Victoria outperformed the national economy in 2008/09 as weak consumption was offset by a strong housing market. The immediate outlook is for weak growth by historical standards, as a contraction in non-dwelling investment and weak manufacturing exports will be only partially offset by improved agricultural exports. The introduction of carbon pricing will play a significant role in determining the medium-term outlook for Victoria, with brown coal generation and electricity-intensive manufacturers expected to be hard hit. This will mean a temporary period of below average growth before the benefits of previous manufacturing and services investment are translated into higher output. Figure A.1-3 shows historical and forecast medium, high, and low GSP growth.

Western Australia

The Western Australian economy held up better than expected in 2008/09, with economic activity in the west driven by strong private investment, reflecting a number of ongoing mining projects. In the short term, Western Australia should benefit from higher global demand for commodities and new Liquefied Natural Gas (LNG) investment, and several iron ore projects are expected to contribute further to GSP growth. However, the single focus of the Western Australian economy makes it highly susceptible to cyclical downturns. Figure A.1-5 shows historical and forecast medium, high, and low GSP growth.

South Australia

The South Australian economy outperformed the national economy in 2008/09, with sustained levels of dwelling and business investment, growth in consumer spending, and low unemployment. Strong growth is expected in the short term as a result of an improved trade performance. Over the longer term, weak population growth will have a strong impact on the construction sector and South Australia is forecast to grow at a slower rate than the national economy. Figure A.1-6 shows historical and forecast medium, high, and low GSP growth.

Tasmania

The Tasmanian economy underperformed the national economy in 2008/09. Economic activity was supported by comparatively strong consumer spending and private investment, but falling net exports. Tasmania's long term growth is expected to be below the national average, reflecting slower growth in the services sector and low population growth. In particular the construction sector is expected to underperform the national average, reflecting weaker demand for housing. Figure A.1-7 shows historical and forecast medium, high, and low GSP growth.

Northern Territory

The Northern Territory experienced strong local business spending but weak trade flows during 2008/09, resulting in weak overall GSP growth. In the near future, improved growth will be driven by renewed consumer spending and an appreciation in export earnings. Defence and other government spending in the region will also support local employment, keeping the unemployment rate below the national average. Over the medium to longer term, the Northern Territory economy should be highly cyclical, similar to other resource-based regions. However, overall growth is expected to outpace the national economy, largely due to stronger population growth. Figure A.1-8 shows historical and forecast medium, high, and low GSP growth.

A1.3.7 State and Territory economic forecasts summary

Table A.1-5 to Table A.1-11 show, for each State and Territory, year-by-year medium, high, and low growth forecasts for population, output, and energy prices. These variables are correlated to the underlying demand for electricity in each region and so influence the ESOO energy and maximum demand projections. However, the extent to which these forecasts directly relate to the regional energy and maximum demand projections depends on the individual forecasting methodologies adopted for each region (see Chapter 3 for more information).

Figure A.1-2—New South Wales (including the Australian Capital Territory) medium, high, and low GSP growth

Figure A.1-3 Victorian medium, high, and low GSP growth

Figure A.1-4 Queensland medium, high, and low GSP growth

Figure A.1-5 Western Australian medium, high, and low GSP growth

Figure A.1-6 South Australian medium, high, and low GSP growth

Figure A.1-7 Tasmanian medium, high, and low GSP growth

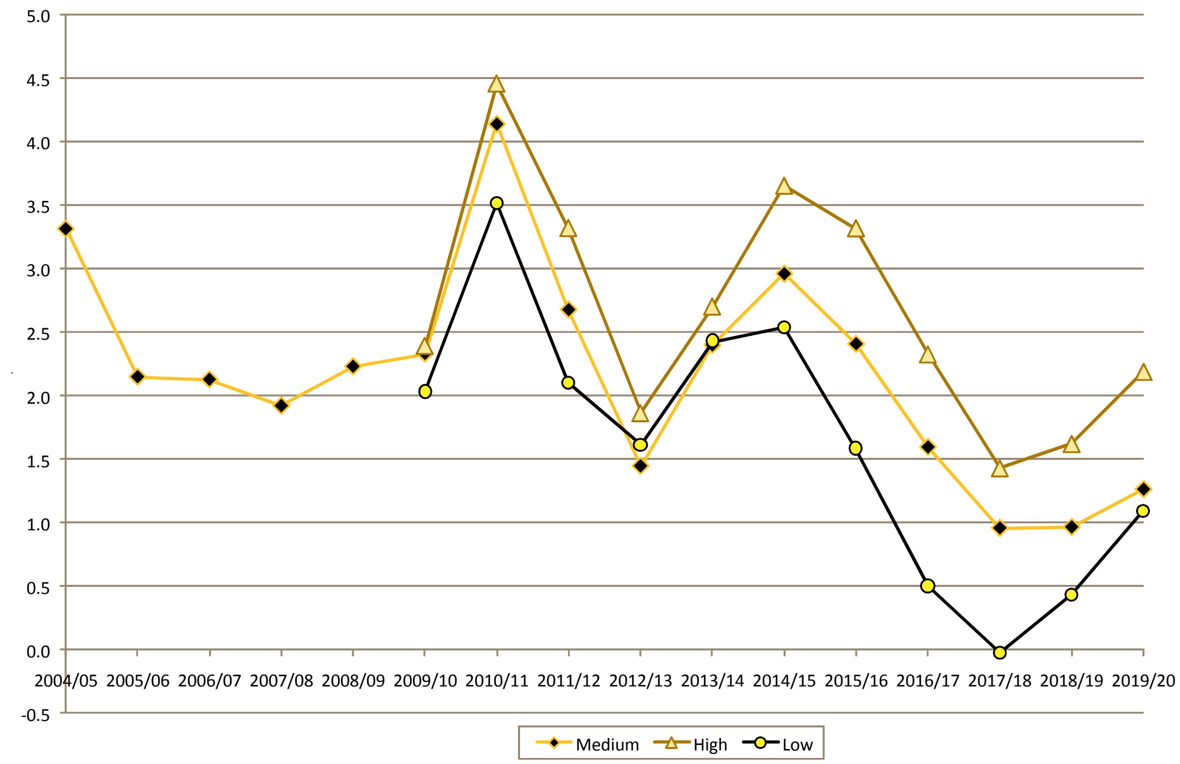


Figure A.1-8 Northern Territory medium, high, and low GSP growth

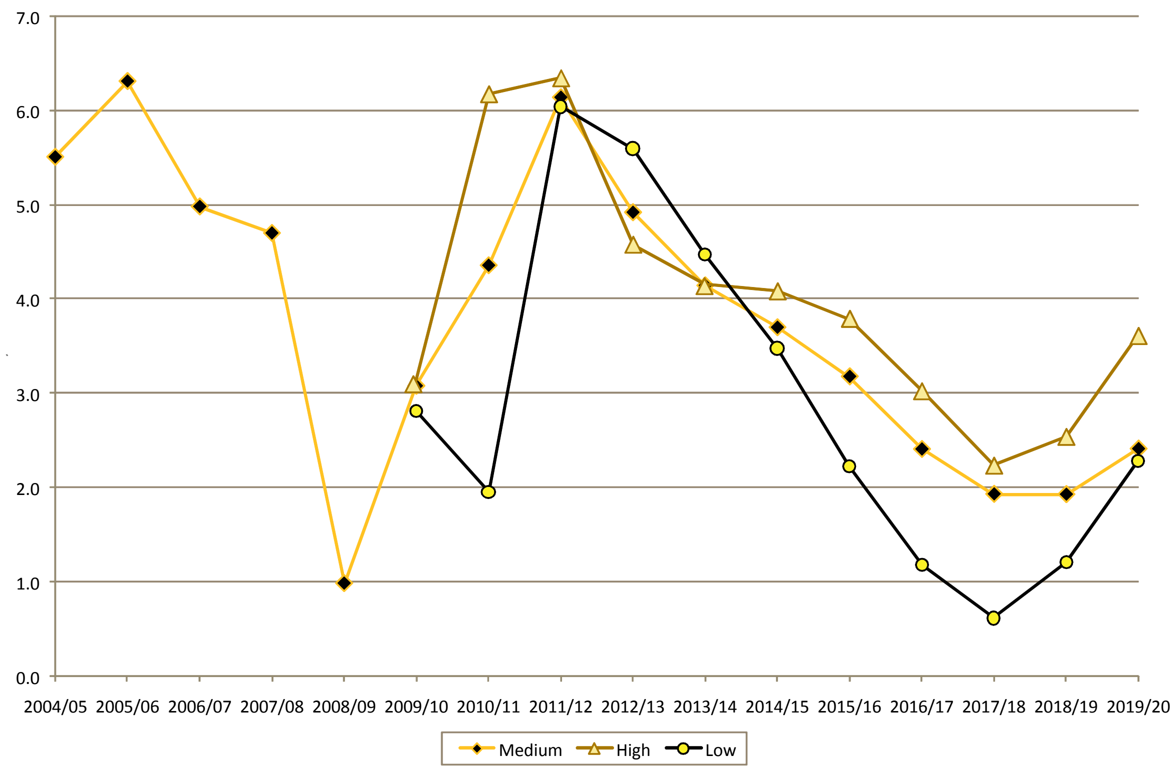


Table A.1-5 New South Wales (including the Australian Capital Territory) medium, high, and low economic growth forecasts

Medium	Population	Gross State Product	Consumer Price Index	Retail Electricity Price	Retail Natural Gas Price Index
	'000s	2006/07 $m	1989/90=100	c/kWh	1989/90=100
2008/09 actual	7,399	369,027	165.9	11.02	233.2
2009/10	7,490	374,829	168.5	10.84	244.8
2010/11	7,570	385,643	171.5	10.84	249.1
2011/12	7,645	397,593	175.6	11.46	260.0
2012/13	7,716	406,253	179.8	13.00	276.3
2013/14	7,788	416,576	183.3	13.24	283.8
2014/15	7,862	429,171	186.6	13.50	289.8
2015/16	7,938	441,269	191.0	13.90	298.5
2016/17	8,014	451,106	196.5	14.39	312.3
2017/18	8,089	459,275	202.7	14.93	330.0
2018/19	8,164	467,396	208.6	15.44	348.0
2019/20	8,239	476,454	213.9	15.88	363.3
Avg forecast growth % p. a.	0.95	2.38	2.49	4.34	4.28

High	Population	Gross State Product	Consumer Price Index	Retail Electricity Price	Retail Natural Gas Price Index
2009/10	7,491	375,143	168.5	10.85	245.0
2010/11	7,577	385,983	170.5	10.80	250.1

High	Population	Gross State Product	Consumer Price Index	Retail Electricity Price	Retail Natural Gas Price Index
2011/12	7,663	398,815	172.8	11.22	257.2
2012/13	7,749	407,959	174.8	12.89	270.3
2013/14	7,840	419,358	176.0	12.99	270.7
2014/15	7,936	434,846	176.9	13.07	269.4
2015/16	8,035	450,392	179.0	13.31	271.9
2016/17	8,134	463,324	182.7	13.69	281.0
2017/18	8,233	473,588	186.9	14.13	294.6
2018/19	8,332	484,711	190.6	14.52	307.7
2019/20	8,431	498,464	193.4	14.81	317.1
Avg forecast growth % p. a.	1.19	2.88	1.41	3.57	2.67

Low	Population	Gross State Product	Consumer Price Index	Retail Electricity Price	Retail Natural Gas Price Index
2009/10	7,479	374,401	168.4	10.78	243.2
2010/11	7,546	384,979	171.2	10.72	245.6
2011/12	7,600	396,583	176.2	11.36	257.4
2012/13	7,648	405,906	181.4	12.61	273.4
2013/14	7,692	416,086	186.9	12.95	285.9
2014/15	7,735	426,842	193.1	13.41	300.4
2015/16	7,779	435,347	200.7	14.06	319.6
2016/17	7,823	440,753	209.3	14.79	343.6
2017/18	7,866	444,326	217.9	15.49	368.7
2018/19	7,909	449,162	225.3	16.10	390.2
2019/20	7,950	455,775	231.8	16.58	406.2
Avg forecast growth % p. a.	0.58	1.89	3.42	4.96	5.75

Table A.1-6 Victorian medium, high, and low economic growth forecasts

Medium	Population	Gross State Product	Consumer Price Index	Retail Electricity Price	Retail Natural Gas Price Index
	'000s	2006/07 $m	1989/90=100	c/kWh	1989/90=100
2008/09 actual	5,385	259,793	164.0	12.38	206.2
2009/10	5,475	263,955	166.3	12.74	218.2
2010/11	5,556	270,453	169.2	12.78	220.0
2011/12	5,634	277,155	173.0	13.64	229.1
2012/13	5,710	281,796	176.7	15.48	241.7
2013/14	5,786	289,030	179.8	15.68	248.3
2014/15	5,864	298,532	182.7	15.97	254.5
2015/16	5,945	307,641	186.6	16.35	261.5
2016/17	6,025	315,153	191.5	16.83	269.8
2017/18	6,106	320,947	196.9	17.39	279.1

Medium	Population	Gross State Product	Consumer Price Index	Retail Electricity Price	Retail Natural Gas Price Index
	'000s	2006/07 $m	1989/90=100	c/kWh	1989/90=100
2018/19	6,187	326,754	202.1	17.98	288.5
2019/20	6,267	333,194	206.6	18.57	297.6
Avg forecast growth % p. a.	1.35	2.35	2.25	4.24	3.41

High	Population	Gross State Product	Consumer Price Index	Retail Electricity Price	Retail Natural Gas Price Index
2009/10	5,476	263,983	166.3	12.74	218.2
2010/11	5,561	270,886	168.3	12.78	219.8
2011/12	5,648	279,017	170.4	13.45	228.3
2012/13	5,735	284,832	172.3	15.63	242.1
2013/14	5,826	293,831	173.3	15.64	246.9
2014/15	5,921	306,092	174.1	15.72	251.0
2015/16	6,019	318,371	176.0	15.92	256.1
2016/17	6,117	328,672	179.3	16.27	262.7
2017/18	6,216	336,731	183.1	16.72	270.3
2018/19	6,315	345,276	186.3	17.20	277.8
2019/20	6,415	355,502	188.7	17.63	284.6
Avg forecast growth % p. a.	1.60	3.07	1.28	3.64	2.91

Low	Population	Gross State Product	Consumer Price Index	Retail Electricity Price	Retail Natural Gas Price Index
2009/10	5,467	263,828	166.2	12.69	218.1
2010/11	5,538	269,314	169.0	12.69	218.6
2011/12	5,601	274,655	173.5	13.59	227.7
2012/13	5,658	279,232	178.2	15.00	238.7
2013/14	5,713	285,835	183.0	15.30	246.6
2014/15	5,768	293,481	188.5	15.74	255.1
2015/16	5,824	299,567	195.2	16.30	264.8
2016/17	5,880	303,517	202.7	16.99	275.7
2017/18	5,936	305,858	210.1	17.72	286.9
2018/19	5,991	309,151	216.5	18.45	297.7
2019/20	6,046	313,785	222.0	19.12	307.8
Avg forecast growth % p. a.	0.98	1.71	3.08	4.66	3.88

Table A.1-7 Queensland medium, high, and low economic growth forecasts

Medium	Population	Gross State Product	Consumer Price Index	Retail Electricity Price	Retail Natural Gas Price Index
	'000s	2006/07 $m	1989/90=100	c/kWh	1989/90=100
2008/09 actual	4,375	208,595	170.9	12.02	229.1

Medium	Population	Gross State Product	Consumer Price Index	Retail Electricity Price	Retail Natural Gas Price Index
	'000s	2006/07 $m	1989/90=100	c/kWh	1989/90=100
2009/10	4,477	217,503	174.2	12.36	241.5
2010/11	4,574	230,987	177.3	12.48	239.5
2011/12	4,670	241,905	182.0	13.44	247.3
2012/13	4,766	250,295	187.0	15.47	259.6
2013/14	4,863	260,391	191.3	15.82	264.4
2014/15	4,963	272,003	195.4	16.22	268.7
2015/16	5,065	282,625	200.6	16.74	276.1
2016/17	5,169	290,975	207.4	17.39	287.8
2017/18	5,273	297,456	215.0	18.10	302.1
2018/19	5,379	304,367	222.5	18.80	316.1
2019/20	5,485	312,473	229.1	19.43	327.9
Avg forecast growth % p. a.	2.04	3.41	2.89	5.04	3.55

High	Population	Gross State Product	Consumer Price Index	Retail Electricity Price	Retail Natural Gas Price Index
2009/10	4,478	217,639	174.2	12.36	241.4
2010/11	4,578	231,437	176.3	12.38	237.3
2011/12	4,682	243,732	178.7	13.05	244.0
2012/13	4,787	252,931	181.1	15.30	253.7
2013/14	4,896	264,670	182.6	15.43	251.7
2014/15	5,010	279,147	183.6	15.61	248.5
2015/16	5,126	293,124	186.1	15.93	249.1
2016/17	5,245	304,232	190.4	16.42	254.7
2017/18	5,364	313,068	195.6	16.99	262.7
2018/19	5,485	322,856	200.1	17.54	269.1
2019/20	5,607	335,228	203.7	17.99	272.6
Avg forecast growth % p. a.	2.28	4.20	1.62	4.25	1.55

Low	Population	Gross State Product	Consumer Price Index	Retail Electricity Price	Retail Natural Gas Price Index
2009/10	4,470	216,960	174.1	12.34	241.1
2010/11	4,560	229,034	177.1	12.43	234.5
2011/12	4,643	238,941	182.7	13.43	241.7
2012/13	4,724	247,707	189.0	15.11	253.9
2013/14	4,803	257,465	195.6	15.64	264.1
2014/15	4,883	267,334	203.2	16.32	277.5
2015/16	4,966	274,689	212.5	17.15	296.0

Low	Population	Gross State Product	Consumer Price Index	Retail Electricity Price	Retail Natural Gas Price Index
2016/17	5,048	279,264	223.2	18.09	318.9
2017/18	5,132	281,991	233.9	18.99	342.7
2018/19	5,216	286,290	243.4	19.76	363.4
2019/20	5,300	292,927	251.7	20.40	380.5
Avg forecast growth % p. a.	1.69	2.77	3.98	5.65	5.52

Table A.1-8 Western Australian medium, high, and low economic growth forecasts

Medium	Population	Gross State Product	Consumer Price Index	Retail Electricity Price	Retail Natural Gas Price Index
	'000s	2006/07 $m	1989/90=100	c/kWh	1989/90=100
2008/09 actual	2,212	149,975	166.6	12.63	197.1
2009/10	2,262	155,805	170.2	13.01	202.5
2010/11	2,308	165,890	173.4	12.94	201.8
2011/12	2,352	174,158	177.7	13.86	203.6
2012/13	2,395	181,637	181.9	15.82	209.8
2013/14	2,439	190,437	185.6	16.07	211.1
2014/15	2,484	198,488	189.0	16.35	212.8
2015/16	2,531	204,149	193.5	16.79	216.7
2016/17	2,578	207,610	199.3	17.42	223.4
2017/18	2,626	210,080	205.7	18.14	230.9
2018/19	2,673	213,400	211.9	18.84	237.2
2019/20	2,722	218,336	217.3	19.48	241.0
Avg forecast growth % p. a.	1.85	3.10	2.54	4.65	1.99

High	Population	Gross State Product	Consumer Price Index	Retail Electricity Price	Retail Natural Gas Price Index
2009/10	2,262	155,859	170.2	13.01	202.4
2010/11	2,310	165,906	172.5	12.85	200.5
2011/12	2,359	174,263	174.7	13.43	200.6
2012/13	2,409	181,667	176.9	15.64	207.8
2013/14	2,460	191,814	178.1	15.59	207.7
2014/15	2,515	202,432	179.0	15.56	207.8
2015/16	2,572	210,645	181.2	15.73	210.7
2016/17	2,629	216,245	184.9	16.14	217.1
2017/18	2,687	220,423	189.3	16.65	224.6
2018/19	2,745	226,558	193.1	17.14	230.0
2019/20	2,804	235,584	196.0	17.55	232.1
Avg forecast growth % p. a.	2.17	3.97	1.43	3.53	1.64

Low	Population	Gross State Product	Consumer Price Index	Retail Electricity Price	Retail Natural Gas Price Index
2009/10	2,259	155,668	170.1	13.03	202.3
2010/11	2,300	164,832	173.2	12.96	199.8
2011/12	2,337	173,071	178.3	13.93	200.6
2012/13	2,371	181,367	183.7	15.46	204.7
2013/14	2,404	189,703	189.3	15.87	208.0
2014/15	2,437	196,082	195.7	16.42	213.5
2015/16	2,471	198,359	203.6	17.19	221.7
2016/17	2,505	198,415	212.6	18.13	231.2
2017/18	2,540	197,710	221.4	19.07	239.4
2018/19	2,574	199,192	229.2	19.92	244.5
2019/20	2,609	203,240	235.9	20.65	246.9
Avg forecast growth % p. a.	1.41	2.35	3.50	5.31	2.38

Table A.1-9 South Australian medium, high, and low economic growth forecasts

Medium	Population	Gross State Product	Consumer Price Index	Retail Electricity Price	Retail Natural Gas Price Index
	'000s	2006/07 $m	1989/90=100	c/kWh	1989/90=100
2008/09 actual	1,617	71,984	169.7	14.42	240.0
2009/10	1,634	75,150	172.9	14.80	249.3
2010/11	1,650	77,502	176.1	14.56	251.3
2011/12	1,664	79,255	180.4	15.41	258.1
2012/13	1,679	80,728	184.7	17.56	272.9
2013/14	1,694	82,965	188.4	17.88	281.0
2014/15	1,709	85,697	191.9	18.12	287.7
2015/16	1,725	88,024	196.4	18.50	296.6
2016/17	1,741	89,811	202.2	19.10	310.3
2017/18	1,757	91,272	208.6	19.85	326.9
2018/19	1,774	92,804	214.8	20.57	342.0
2019/20	1,790	94,483	220.2	21.13	353.0
Avg forecast growth % p. a.	0.91	2.23	2.52	4.23	3.85

High	Population	Gross State Product	Consumer Price Index	Retail Electricity Price	Retail Natural Gas Price Index
2009/10	1,635	75,367	172.8	14.72	249.2
2010/11	1,651	77,679	175.1	14.48	249.4
2011/12	1,668	79,840	177.5	15.05	253.6
2012/13	1,686	81,648	179.6	17.34	267.9
2013/14	1,705	84,495	180.9	17.34	271.6
2014/15	1,725	88,138	181.8	17.29	273.1
2015/16	1,746	91,480	184.0	17.47	277.6

High	Population	Gross State Product	Consumer Price Index	Retail Electricity Price	Retail Natural Gas Price Index
2016/17	1,768	94,203	187.7	17.95	288.4
2017/18	1,789	96,291	192.2	18.62	302.4
2018/19	1,811	98,710	196.0	19.19	313.1
2019/20	1,832	101,562	198.9	19.54	318.1
Avg forecast growth % p. a.	1.16	3.02	1.43	3.38	2.74

Low	Population	Gross State Product	Consumer Price Index	Retail Electricity Price	Retail Natural Gas Price Index
2009/10	1,632	74,829	172.7	14.70	249.0
2010/11	1,645	76,960	175.8	14.42	248.4
2011/12	1,655	78,283	181.0	15.30	254.4
2012/13	1,665	79,601	186.5	17.12	268.2
2013/14	1,673	81,493	192.1	17.63	281.5
2014/15	1,682	83,447	198.6	18.19	296.2
2015/16	1,691	84,802	206.5	18.92	313.7
2016/17	1,700	85,665	215.5	19.81	334.0
2017/18	1,709	86,210	224.3	20.72	353.9
2018/19	1,718	87,132	232.1	21.43	369.4
2019/20	1,727	88,420	238.9	21.93	380.6
Avg forecast growth % p. a.	0.55	1.55	3.46	4.77	4.85

Table A.1-10 Tasmanian medium, high, and low economic growth forecasts

Medium	Population	Gross State Product	Consumer Price Index	Retail Electricity Price	Retail Natural Gas Price Index
	'000s	2006/07 $m	1989/90=100	c/kWh	1989/90=100
2008/09 actual	503	21,067	164.9	9.96	209.6
2009/10	507	21,564	167.8	10.39	215.7
2010/11	512	22,475	170.5	10.59	216.7
2011/12	515	23,085	174.8	11.22	226.5
2012/13	519	23,420	179.5	12.63	239.2
2013/14	522	23,989	183.4	12.82	242.8
2014/15	526	24,709	187.3	13.17	245.9
2015/16	530	25,311	192.2	13.74	253.8
2016/17	533	25,718	198.6	14.45	266.4
2017/18	537	25,965	205.8	15.20	279.7
2018/19	541	26,216	212.8	15.93	290.1
2019/20	544	26,549	219.0	16.60	296.5
Avg forecast growth % p. a.	0.69	1.87	2.82	5.12	3.54

High	'000s Population	2006/07 $m Gross State Product	1989/90=100 Consumer Price Index	c/kWh Retail Electricity Price	1989/90=100 Retail Natural Gas Price Index
2009/10	508	21,577	167.7	10.38	215.5
2010/11	512	22,560	169.5	10.54	213.4
2011/12	516	23,321	171.7	11.06	218.1
2012/13	520	23,760	173.9	12.81	229.0
2013/14	524	24,411	175.2	12.91	228.6
2014/15	528	25,318	176.2	13.10	227.9
2015/16	532	26,172	178.5	13.46	233.3
2016/17	536	26,788	182.6	13.92	244.8
2017/18	541	27,174	187.5	14.42	257.0
2018/19	545	27,618	191.8	14.93	264.4
2019/20	549	28,229	195.1	15.44	267.2
Avg forecast growth % p. a.	0.78	2.52	1.57	4.34	2.53

Low	Population	Gross State Product	Consumer Price Index	Retail Electricity Price	Retail Natural Gas Price Index
2009/10	507	21,500	167.7	10.41	215.2
2010/11	510	22,269	170.2	10.59	214.3
2011/12	513	22,742	175.5	11.15	225.3
2012/13	516	23,112	181.4	12.14	237.8
2013/14	518	23,679	187.5	12.30	246.3
2014/15	521	24,288	194.6	12.72	257.2
2015/16	524	24,676	203.4	13.42	272.9
2016/17	526	24,801	213.5	14.36	290.8
2017/18	529	24,795	223.5	15.41	305.6
2018/19	531	24,903	232.4	16.49	314.2
2019/20	534	25,178	240.2	17.47	318.7
Avg forecast growth % p. a.	0.50	1.37	3.90	5.72	4.51

Table A.1-11 Northern Territory medium, high, and low economic growth forecasts

Medium	Population '000s	Gross State Product 2006/07 $m	Consumer Price Index 1989/90=100	Retail Electricity Price c/kWh	Retail Natural Gas Price Index 1989/90=100
2008/09 actual	230	15,285	167.6	15.47	266.4
2009/10	234	15,966	170.7	15.47	277.8
2010/11	238	16,976	174.3	16.34	292.0
2011/12	242	17,832	177.7	18.43	311.3
2012/13	246	18,586	180.5	18.63	322.0
2013/14	250	19,286	183.1	18.84	331.9
2014/15	254	19,908	186.7	19.06	343.9
2015/16	257	20,393	191.1	19.30	359.7

Medium	Population	Gross State Product	Consumer Price Index	Retail Electricity Price	Retail Natural Gas Price Index
	'000s	2006/07 $m	1989/90=100	c/kWh	1989/90=100
2016/17	261	20,791	196.0	19.57	378.4
2017/18	265	21,195	200.6	19.85	397.8
2018/19	268	21,712	204.6	20.12	415.8
2019/20	1.52	3.47	2.03	2.96	4.58
Avg forecast growth % p. a.	230	15,285	167.6	15.47	266.4

High	Population	Gross State Product	Consumer Price Index	Retail Electricity Price	Retail Natural Gas Price Index
2009/10	230	15,294	167.6	15.47	266.4
2010/11	234	16,268	169.9	15.47	275.7
2011/12	239	17,333	171.9	16.20	282.4
2012/13	243	18,144	173.6	19.01	288.0
2013/14	247	18,915	174.5	19.18	291.4
2014/15	251	19,703	175.2	19.36	293.6
2015/16	256	20,464	177.0	19.57	298.0
2016/17	260	21,092	180.0	19.82	306.5
2017/18	264	21,568	183.5	20.09	317.9
2018/19	268	22,122	186.3	20.38	329.1
2019/20	272	22,934	188.5	20.65	338.1
Avg forecast growth % p. a.	1.68	3.89	1.16	3.26	2.29

Low	Population	Gross State Product	Consumer Price Index	Retail Electricity Price	Retail Natural Gas Price Index
2009/10	230	15,245	167.5	15.46	266.2
2010/11	234	15,546	170.5	15.47	277.2
2011/12	237	16,514	174.8	16.31	292.8
2012/13	240	17,464	179.1	17.71	311.8
2013/14	243	18,263	183.4	17.91	327.5
2014/15	246	18,909	188.4	18.13	345.3
2015/16	250	19,335	194.5	18.37	367.1
2016/17	253	19,564	201.3	18.64	393.0
2017/18	255	19,685	207.8	18.90	420.2
2018/19	258	19,925	213.4	19.15	445.3
2019/20	261	20,385	218.2	19.37	467.3
Avg forecast growth % p. a.	1.25	3.06	2.78	2.53	5.97

Attachment 2 - Supply-Demand Outlook: Additional Information

A2.1 Summary

This attachment supplements Chapter 7, providing additional information about the future adequacy of electricity supplies in the National Electricity Market (NEM) under low and high economic growth scenarios. It also presents a list of violating network constraint equations that were removed from the supply-demand outlook calculations.

A supply-demand outlook is presented for each region and highlights potential generation and demand-side investment opportunities due to projected shortfalls in existing and committed supply. In particular, the regional outlooks identify the timing of low reserve condition (LRC) points, indicating where reserve margins will fall below the minimum reserve level (MRL). Under these conditions, the Australian Energy Market Operator (AEMO) may investigate the need for market intervention to maintain power system reliability.

Table A.2-1 lists an overview of the supply-demand outlook results for 2010 and includes low, medium, and high economic growth scenarios.

Table A.2-1—Supply-demand outlook overview

Region	Low economic growth		Medium economic growth		High economic growth	
	LRC point	Reserve deficit (MW)	LRC point	Reserve deficit (MW)	LRC point	Reserve deficit (MW)
Queensland	2015/16	184	**2013/14**	**726**	2012/13	716
New South Wales	2017/18	91	**2016/17**	**27**	2016/17	285
Victoria	2017/18	135	**2015/16**	**249**	2014/15	222
South Australia	2017/18	11	**2015/16**	**50**	2012/13	85
Tasmania (summer)	>2019/20	N/A	**> 2019/20**	**N/A**	>2019/20	N/A
Tasmania (winter)	>2020	N/A	**> 2020**	**N/A**	>2020	N/A

The regional outlooks examined in the remainder of this attachment provide graphical results for the low and high economic-growth scenario only. See Chapter 7 for a full set of results for the medium growth scenario.

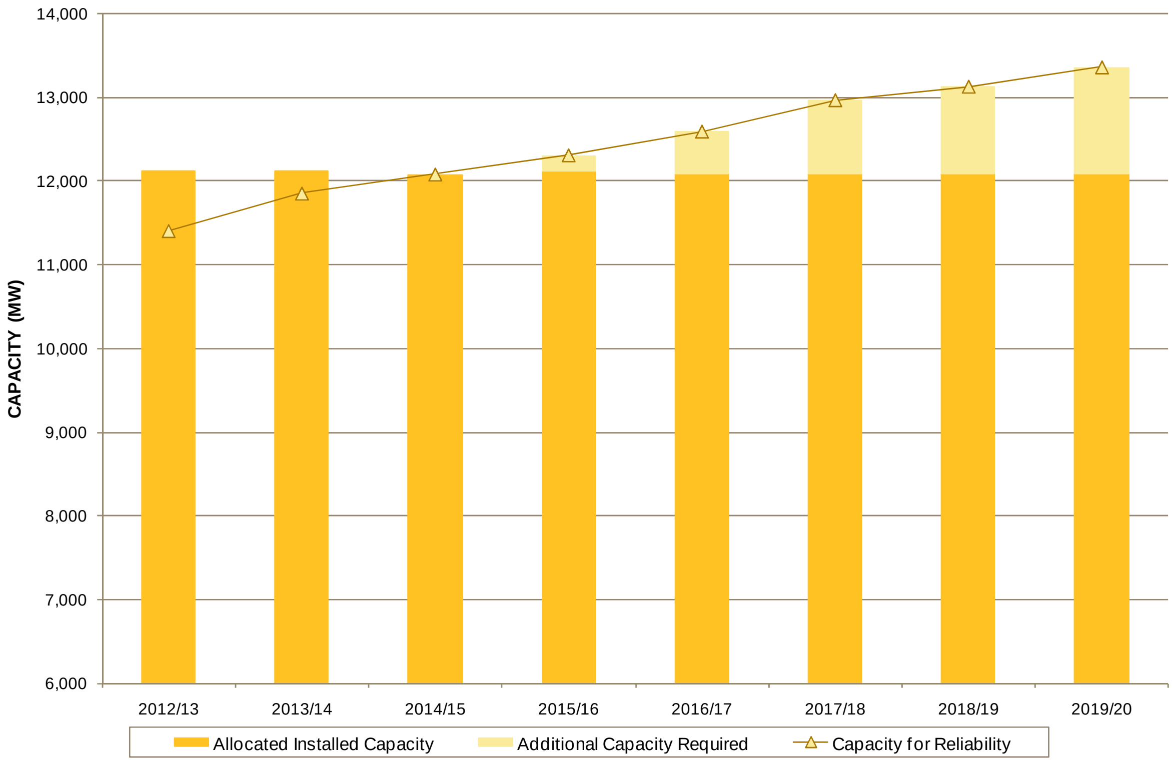
A2.2 Regional outlooks

A2.2.1 Queensland summer outlook – low economic growth

Figure A.2-1 presents the projected Queensland summer supply-demand outlook for 2012/13-2019/20 under the low economic growth scenario.

The figure indicates that, with low economic growth, Queensland reaches its LRC point in 2015/16, requiring an additional 184 MW of local capacity to delay this shortfall until the following year.

Figure A.2-1—Queensland summer supply-demand outlook – low economic growth

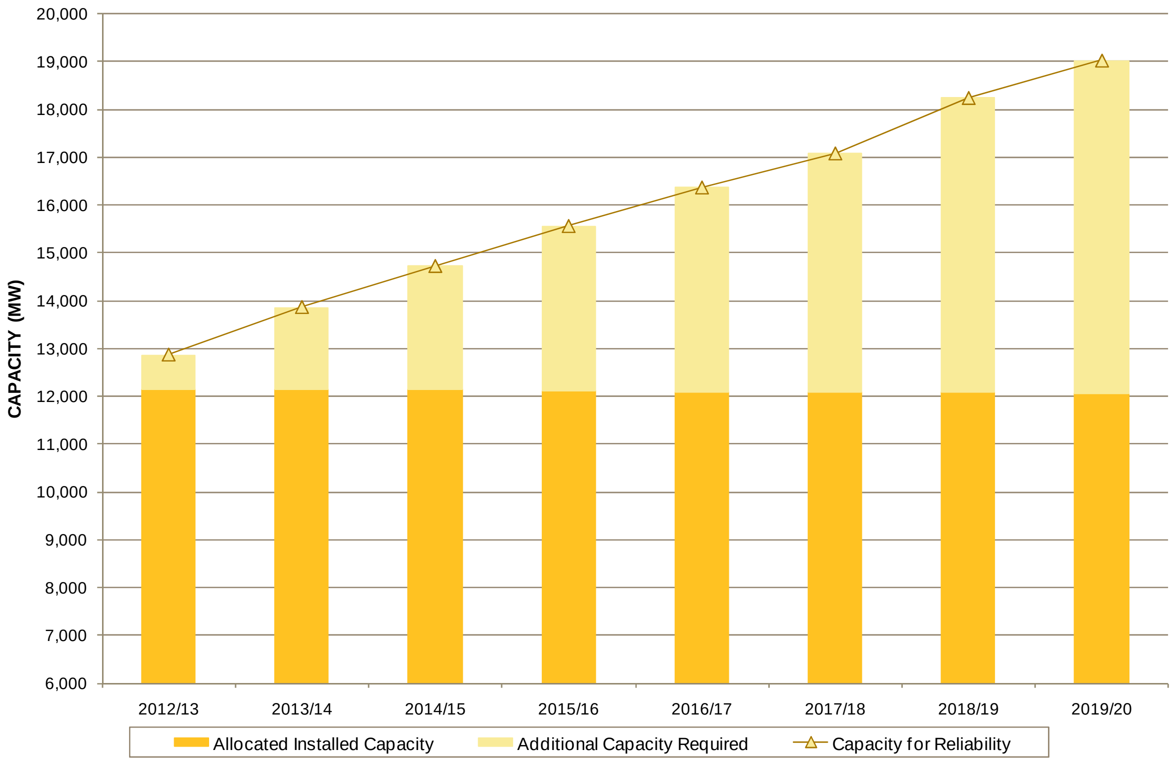


A2.2.2 Queensland summer outlook – high economic growth

Figure A.2-2 presents the projected Queensland summer supply-demand outlook for 2012/13-2019/20 under the high economic growth scenario.

The figure indicates that, with low economic growth, Queensland reaches its LRC point in 2012/13, requiring an additional 716 MW of local capacity to delay this shortfall until the following year.

Figure A.2-2—Queensland summer supply-demand outlook – high economic growth

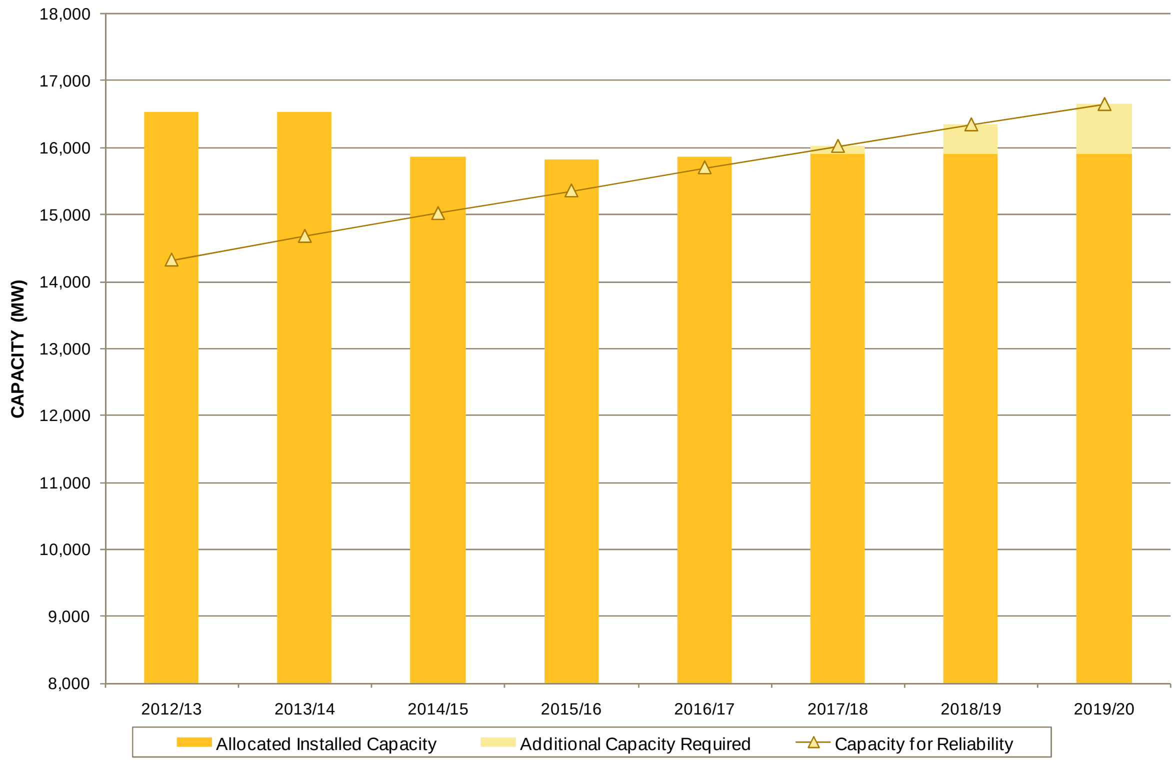


A2.2.3 New South Wales summer outlook – low economic growth

Figure A.2–3 presents the projected New South Wales summer supply-demand outlook for 2012/13-2019/20 under the low economic growth scenario.

The figure indicates that, with low economic growth, New South Wales reaches its LRC point in 2017/18, requiring an additional 91 MW of local capacity to delay this shortfall until the following year.

Figure A.2-3—New South Wales summer supply-demand outlook – low economic growth

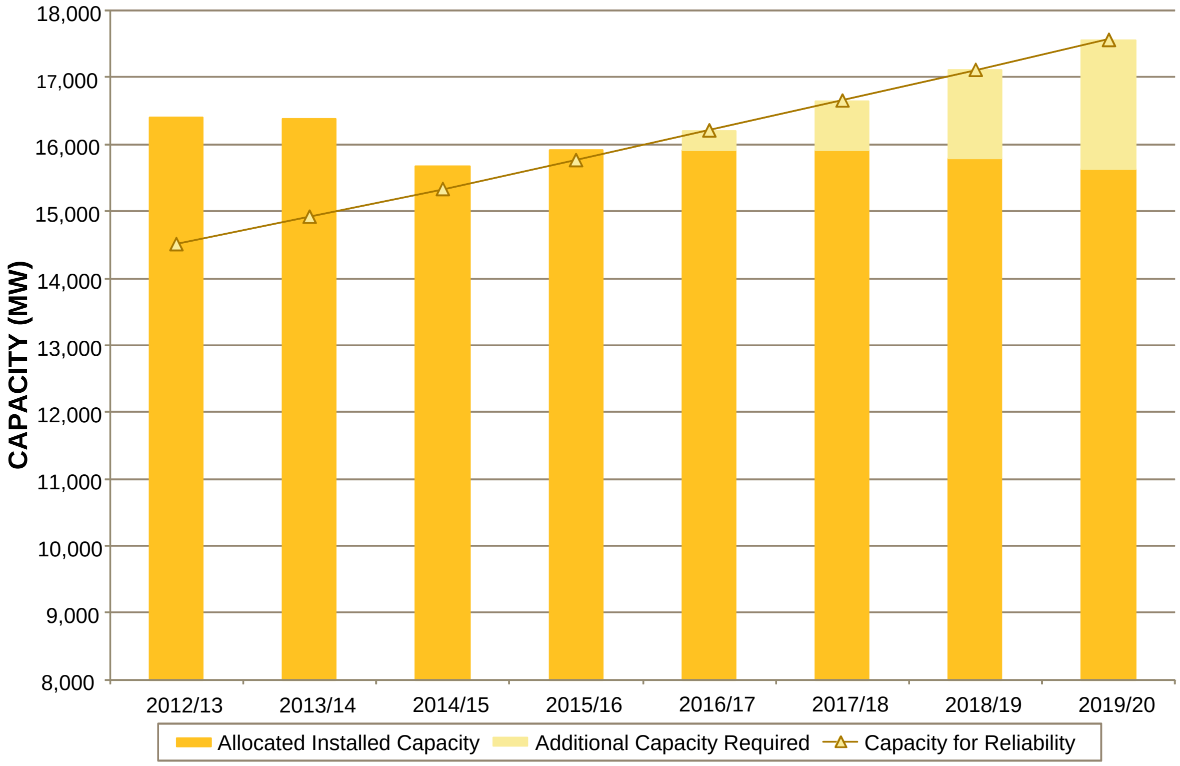


A2.2.4 New South Wales summer outlook – high economic growth

Figure A.2-4 presents the projected New South Wales summer supply-demand outlook for 2012/13-2019/20 under the high economic growth scenario.

The figure indicates that, with high economic growth, New South Wales reaches its LRC point in 2016/17, requiring an additional 285 MW of local capacity to delay this shortfall until the following year.

Figure A.2-4—New South Wales summer supply-demand outlook – high economic growth

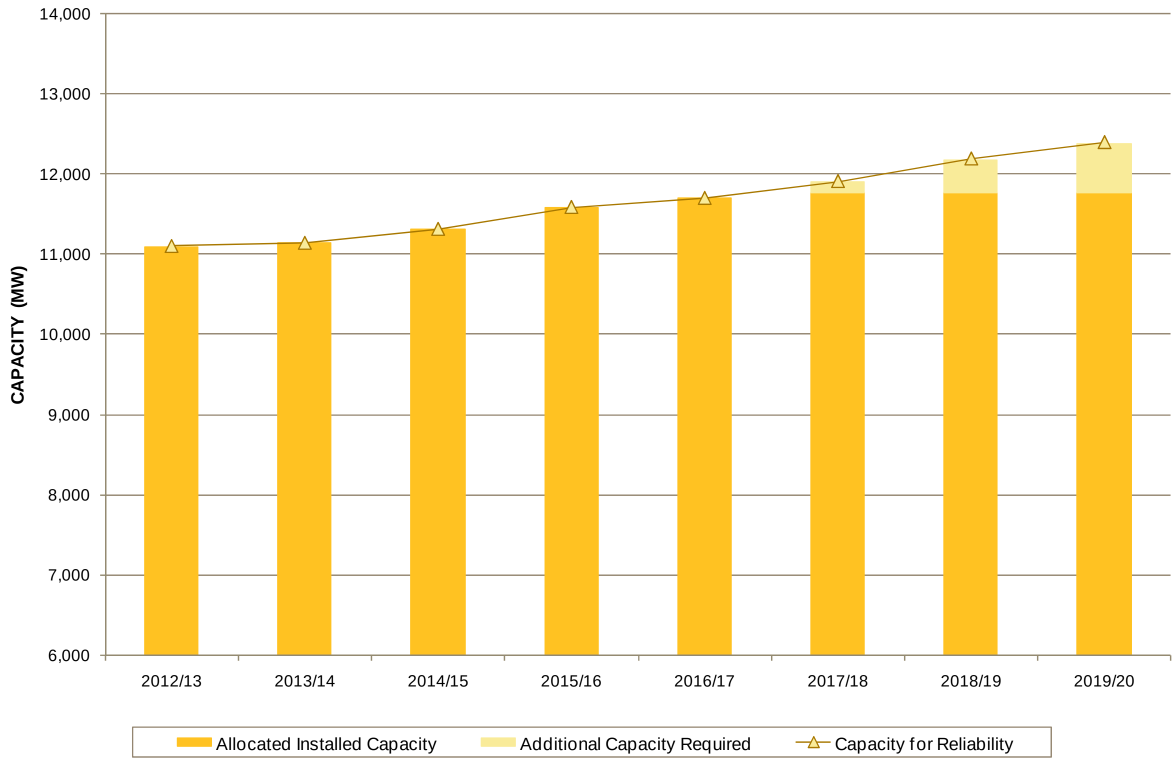


A2.2.5 Victorian summer outlook – low economic growth

Figure A.2-5 presents the projected Victorian summer supply-demand outlook for 2012/13-2019/20 under the low economic growth scenario.

The figure indicates that, with low economic growth, Victoria reaches its LRC point in 2017/18, requiring an additional 135 MW of local capacity to delay this shortfall until the following year.

Figure A.2-5— Victorian summer supply-demand outlook – low economic growth

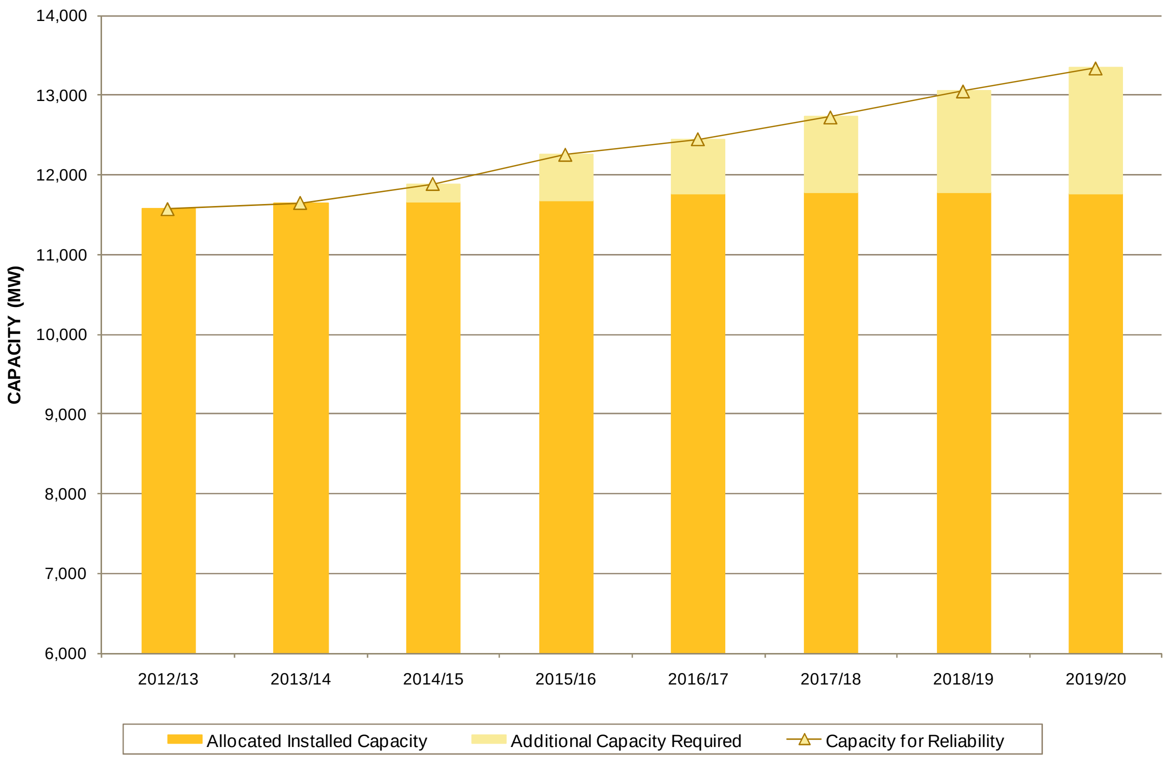


A2.2.6 Victorian summer outlook – high economic growth

Figure A.2-6 presents the projected Victorian summer supply-demand outlook for 2012/13-2019/20 under the high economic growth scenario.

The figure indicates that, with high economic growth, Victoria reaches its LRC point in 2014/15, requiring an additional 222 MW of local capacity to delay this shortfall until the following year.

Figure A.2-6— Victorian summer supply-demand outlook – high economic growth

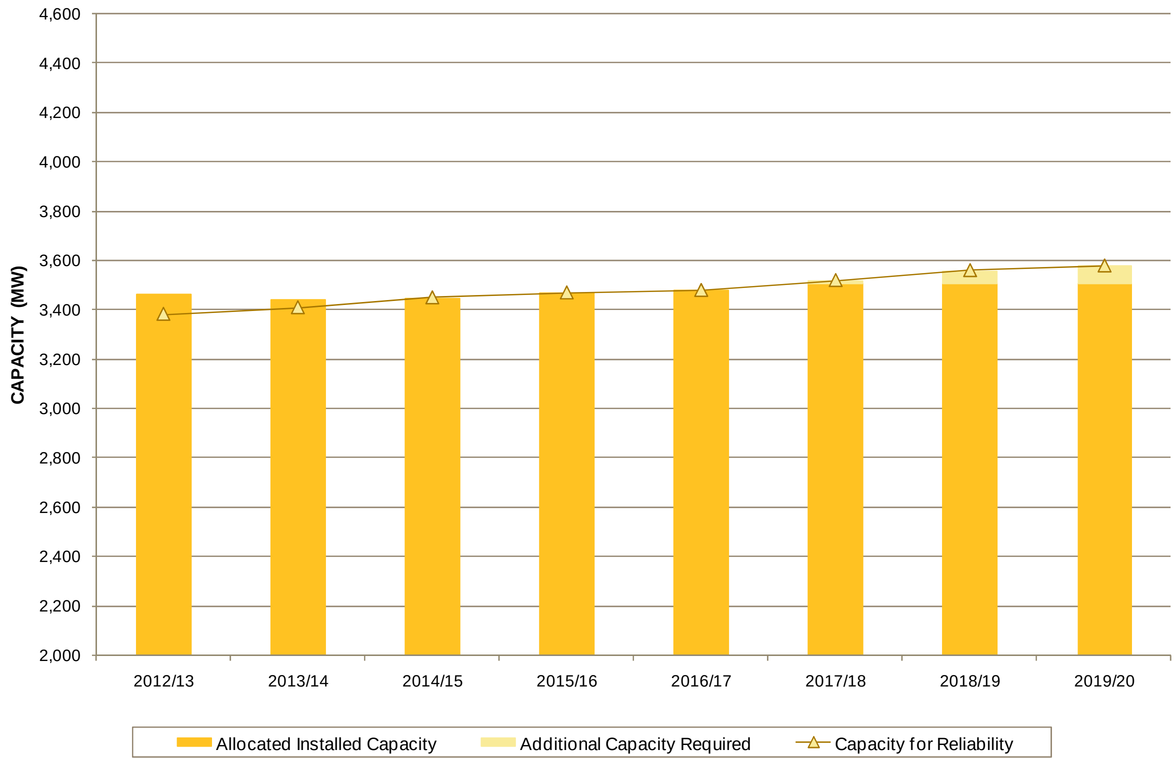


A2.2.7 South Australian summer outlook – low economic growth

Figure A.2-7 presents the projected South Australian summer supply-demand outlook for 2012/13-2019/20 under the low economic growth scenario.

The figure indicates that, with low economic growth, South Australia reaches its LRC point in 2017/18, requiring an additional 11 MW of local capacity to delay this shortfall until the following year.

Figure A.2-7— South Australian summer supply-demand outlook – low economic growth

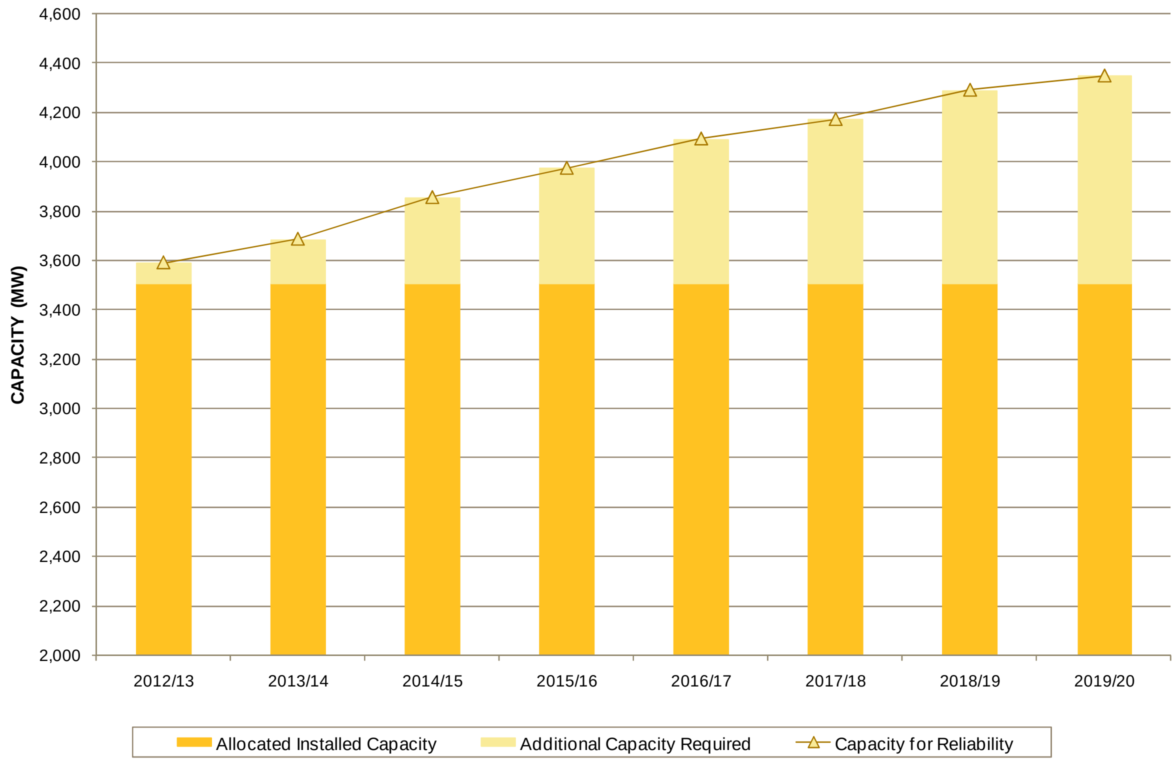


A2.2.8 South Australian summer outlook – high economic growth

Figure A.2-8 presents the projected South Australian summer supply-demand outlook for 2012/13-2019/20 under the high economic growth scenario.

The figure indicates that, with high economic growth, South Australia reaches its LRC point in 2012/13, requiring an additional 85 MW of local capacity to delay this shortfall until the following year.

Figure A.2-8— South Australian summer supply-demand outlook – high economic growth



A2.2.9 Tasmanian summer and winter outlook – low economic growth

Figure A.2-8 presents the projected Tasmanian summer supply-demand outlook for 2012/13-2019/20 under the low economic growth scenario. As Tasmanian demand peaks in winter, the winter outlook has also been provided in Figure A.2-10.

The figures together indicate that, with low economic growth, no LRC point is forecast for Tasmania within the outlook period.

Figure A.2-9—Tasmanian summer supply-demand outlook – low economic growth

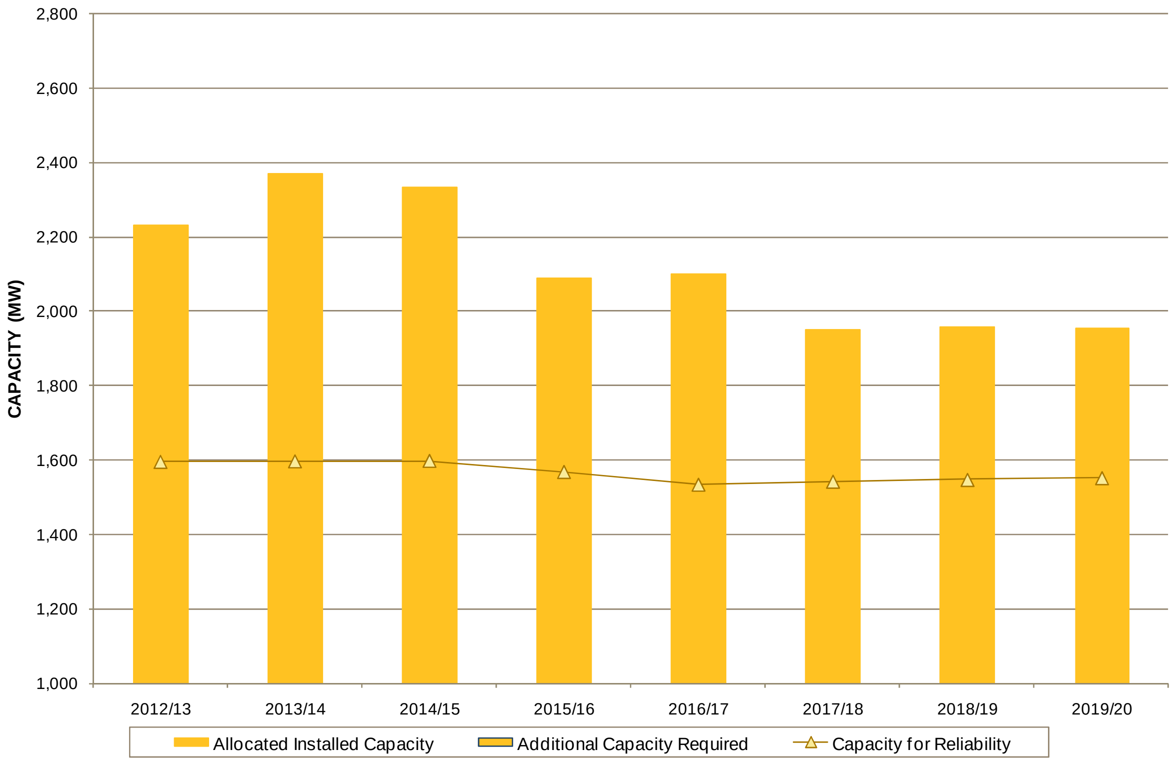
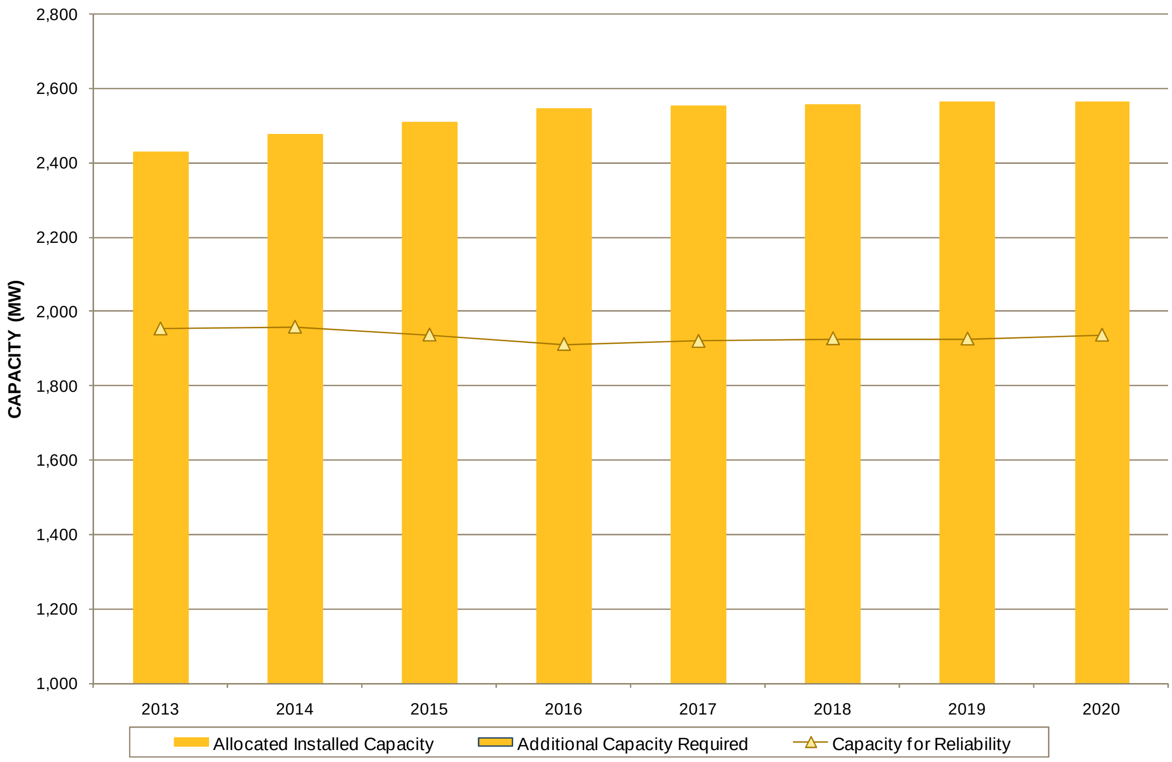


Figure A.2-10—Tasmanian winter supply-demand outlook – low economic growth



A2.2.10 Tasmanian summer and winter outlook – high economic growth

Figure A.2-11 presents the projected Tasmanian summer supply-demand outlook for 2012/13-2019/20 under the high economic growth scenario. As Tasmanian demand peaks in winter, the winter outlook has also been provided in Figure 7-7.

The figures together indicate that, with high economic growth, no LRC point is forecast for Tasmania within the outlook period.

Figure A.2-11—Tasmanian summer supply-demand outlook – high economic growth

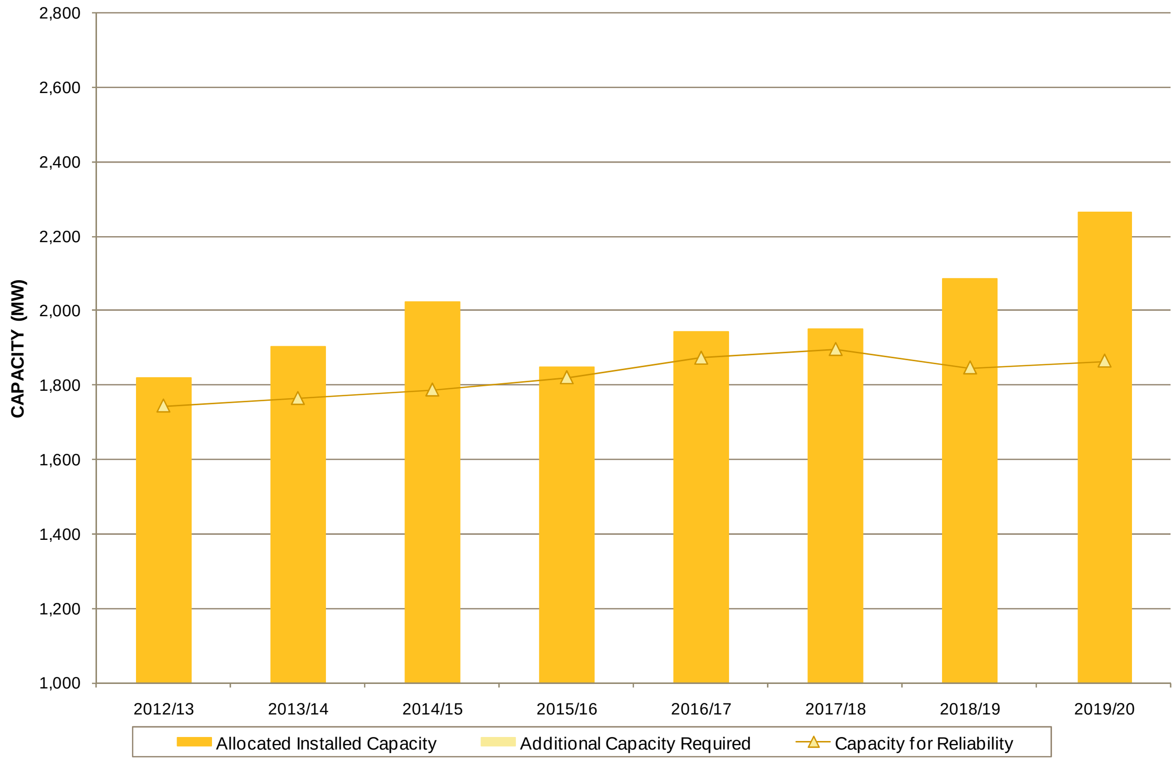
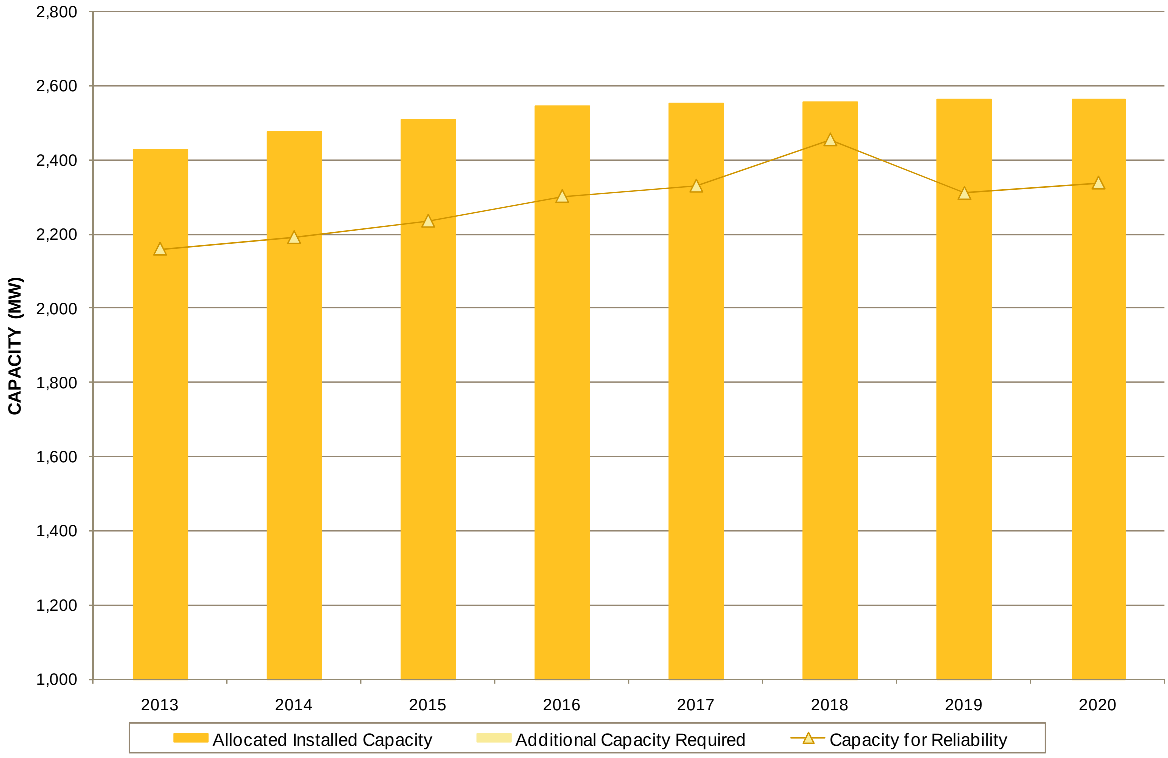


Figure A.2-12—Tasmanian winter supply-demand outlook – high economic growth



A3.1 Constraint equations removed from the supply-demand calculator

Supply-demand calculator network constraint equations occasionally need to be disabled to avoid constraint equation violations.

The disabled constraint equations include:

- constraint equations to avoid overloading a Marulan-Bannaby 330 kV circuit, disabled for all summer and winter runs
- a constraint equation to avoid overloading a Mintaro-Waterloo 132 kV circuit in the event of a trip of the Brinkworth-Para 275 kV circuit, disabled for all summer and winter runs
- a constraint equation to avoid overloading a Mintaro-Waterloo 132 kV circuit with no outage, disabled for all summer and winter runs
- a constraint equation to avoid overloading a Upper Tumut-Lower Tumut 330 kV circuit with no outage, disabled for all summer and winter runs
- a constraint equation to avoid overloading the No.1 Dederang 330/220kV transformer with the DBUSS-Transformer control scheme armed with no outage, disabled from summer 2015/16
- a constraint equation to avoid overloading a North West Bend-Robertstown 132 kV circuit with no outage, disabled from summer 2015/16 (disabled from 2014/15 in high economic growth scenario)
- a constraint equation to avoid overloading a Robertstown-Morgan Whyalla Pipeline 3 132 kV circuit with no outage, disabled from summer 2016/17

- a constraint equation to avoid overloading a Morgan Whyalla Pipeline 1-North West Bend 132 kV circuit with no outage, disabled from summer 2016/17
- a constraint equation to avoid overloading a Waterloo-Morgan Whyalla Pipeline 4 132 kV circuit in the event of a trip of one Robertstown 275/132 kV transformer, disabled from summer 2017/18
- a constraint equation to avoid overloading the Robertstown 275/132 kV transformers with no outage, disabled from summer 2016/17 in high economic growth scenario only
- a constraint equation to avoid overloading a Para-Magill 275 kV circuit for loss of a Torrens-Magill 275 kV circuit, disabled from summer 2016/17 in high economic growth scenario only, and
- a constraint equation to avoid overloading a Bendigo-Fosterville-Shepparton 220 kV circuit in the event of a trip of a Moorabool 500/220kV transformer, disabled from summer 2019/20 in high economic growth scenario only.

Glossary

The Glossary is divided into three sections. The first section lists abbreviations used throughout the document, and provides the expanded name for each. The second section defines commonly used terms. The third section lists the company names used in the document, along with their full company names and ABN numbers.

Abbreviations

Abbreviation	Expanded name
1P	Proved reserves
2P	Proved reserves + probable reserves
3P	Proved + probable + possible reserves
AAPG	American Association of Petroleum Geologists
ABARE	Australian Bureau of Agricultural and Resource Economics
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AEST	Australian Eastern Standard Time (see also EDST)
AMDQ	Authorised Maximum Daily Quantity
ANTS	Annual National Transmission Statement
APR	Annual Planning Report
AWEFS	Australian Wind Energy Forecasting System
BB	Bulletin Board - refers to Natural Gas Services Bulletin Board
BOM	Bureau of Meteorology
CAGR	Compound average growth rate
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CGP	Carpentaria Gas Pipeline
CO2-e	Carbon Dioxide Equivalent
COAG	Council of Australian Governments
CPI	Consumer price index
CPRS	Carbon Pollution Reduction Scheme
CPT	Cumulative Price Threshold
CSG	Coal Seam Gas. Also referred to as coal seam methane (CSM) and coal bed methane (CBM)
DB	Distribution business
DD	Degree Day
DNSP	Distribution Network Service Provider
DRA	Demand Response Aggregator
DSP	Demand-side participation
E&P	Exploration and Production sector
EAPL	East Australian Pipeline Limited
EAAP	Energy Adequacy Assessment Projection
EAPR	Electricity Annual Planning Report
EDD	Effective Degree Day

Abbreviation	Expanded name
EDST	Eastern Daylight Savings Time (see also AEST)
EG	Economic growth
EGP	Eastern Gas Pipeline
EHV	Extra high voltage
EITE	Emissions-Intensive Trade-Exposed (assistance program)
ESC	Essential Services Commission
ESA	Eastern and South Eastern Australia
ESAS	Electricity Sector Adjustment Scheme
ESIPC	Electricity Supply Industry Planning Council (now part of the Australian Energy Market Operator - AEMO)
ESOO	Electricity Statement of Opportunities
ETS	Emissions Trading Scheme
EUR	Estimated Ultimate Recovery
FCAS	Frequency Control Ancillary Service
FCSPS	Frequency Control Special Protection Scheme
FEED	Front-End Engineering and Design
FODWG	Forced Outage Data Working Group
FPWG	Flow Path Working Group
GDP	Gross Domestic Product
GJ	Gigajoule. An SI unit, 1 GJ equals 1x109 Joules
GRP	Gross regional product
GSOO	Gas Statement of Opportunities
GSP	Gross State Product
GST	Goods and Services Tax
GWh	Gigawatt hours
HDD	Heating Degree Day
HVDC	High-voltage direct current
IDGCC	Integrated Drying and Gasification Combined Cycle
IGCC	Integrated Gasification Combined Cycle
IRPC	Inter-Regional Planning Committee
JPB	Jurisdictional Planning Body
k	Thousand
km	Kilometres
kPa	Kilopascal. A unit for measuring gas pressure
kV	Kilovolts
LFRG	Load Forecasting Reference Group
LNG	Liquefied Natural Gas
LOR (1, 2, or 3)	Lack of Reserve
LPG	Liquid petroleum gas
LRA	Long-run average
LRC	Low Reserve Condition
LRPP	Last Resort Planning Power
M	Million
MAOP	Maximum allowable operating pressure
MAP	Moomba Adelaide Pipeline
MCE	Ministerial Council on Energy
MCMPR	Ministerial Council on Mineral and Petroleum Resources
MD	Maximum Demand

Abbreviation	Expanded name
MEPS	Minimum Energy Performance Standards
MLF	Marginal Loss Factor
MMA	McLennan Magasanik Associates
MNSP	Market Network Service Provider
MMS	Market Management Systems
MMt/a	Million, million tonnes per annum
MPC	Market Price Cap
MRET	Mandatory Renewable Energy Target
MRL	Minimum Reserve Level
MSOR, M & S O Rules	The Market and System Operations Rules (Victorian gas industry)
MSP	Moomba to Sydney Pipeline
MSWG	Market Simulations Working Group
MT PASA	Medium-term Projected Assessment of System Adequacy
Mtpa	Million tonnes per annum
MVA	Megavolt amperes
MVAr	Megavolt amperes reactive
MW	Megawatts
MWh	Megawatt hours
NCAS	Network Control Ancillary Services
NCS	Network Control Services
NSCS	Network Support and Control Services
NEL	National Electricity Law
NEM	National Electricity Market
NEMDE	National Electricity Market Dispatch Engine
NEMMCO	National Electricity Market Management Company (now part of AEMO)
NER	National Electricity Rules
NGL	National Gas Law
NGO	National Gas Objective
NGR	National Gas Rules
NIEIR	National Institute of Economic and Industry Research
NLCAS	Network Loading Control Ancillary Service
NMNS	Non-market non-schedule
NPV	Net present value
NSA	Network Support Agreement
NSP	Network Service Provider
NTFP	National Transmission Flow Path
NTNDP	National Transmission Network Development Plan
NTP	National Transmission Planner
NTS	National Transmission Statement
OCGT	Open Cycle Gas Turbine
PASA	Projected Assessment of System Adequacy
PJ	Petajoule
POD	Power Oscillation Damper
POE	Probability of Exceedence
PR	Proved reserves
PSS	Power System Stabilisers
PV	Present Value

Abbreviation	Expanded name
QGP	Queensland Gas Pipeline
QSN link	The Ballera to Moomba interconnect connects Queensland to South Australia, Victoria,
RBP	Roma to Brisbane Pipeline
REC	Renewable Energy Certificate
RET	Renewable Energy Target - National Renewable Energy Target scheme
RERT	Reliability and Emergency Reserve Trader
RIT-T	Regulatory Investment Test for Transmission
RP	Reserves to production ratio
RPAS	Reactive Power Ancillary Service
SCADA	Supervisory Control and Data Acquisition
SEA	South East Australia Gas Pipeline
SENE	Scale Efficient Network Extensions
SMHS	Snowy Mountains Hydroelectric Scheme
SPE	Society of Petroleum Engineers
SPEE	Society of Petroleum Evaluation Engineers
SRA	Settlements Residue Auction
SRAS	System Restart Ancillary Service
SRMC	Short Run Marginal Cost
ST PASA	Short-term Projected Assessment of System Adequacy
STTM	Short-term Trading Market for Gas
SVC	Static VAr Compensator
SWP	Southwest Pipeline
SWQP	South West Queensland Pipeline
TGP	Tasmanian Gas Pipeline
TJ	Terajoule
TJ/d	Terajoules per day. See also Terajoule
TNSP	Transmission Network Service Provider
TOC	Transmission Operations Centre (formally VNSC)
TUOS	Transmission Use of System
UIGF	Unconstrained Intermittent Generation Forecast
USE	Unserved Energy
VCR	Value of Customer Reliability
VENCorp	Victorian Energy Network Corporation (now part of AEMO)
VoLL	Value of Lost Load
WPC	World Petroleum Council

Definitions

Many of the terms used in this document are already defined in the National Electricity Rules (NER), version 30[66]. For ease of reference, these terms are highlighted in *yellow*. Some terms, although defined in the NER, have been clarified here, and these terms are highlighted in *orange*.

[66] An electronic copy of the latest version of the Rules can be obtained from http://www.aemc.gov.au/rules.php.

Term	Definition
active power	See electrical power.
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 – generation. See also 'proposed project' and 'publicly announced proposal'.
allocated installed capacity	The generation capacity allocated to a region when assessing the reliability of supply. Allocated installed 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'.
ancillary services	Services used by the Australian Energy Market Operator (AEMO) that are essential for: • managing power system security • facilitating orderly trading, and • ensuring electricity supplies are of an acceptable quality. This includes services used to control frequency, voltage, network loading and system restart processes, which would not otherwise be voluntarily provided by market participants on the basis of energy prices alone. Ancillary services may be obtained by AEMO through either market or non-market arrangements.
annual planning report	An annual report providing forecasts of gas or electricity (or both) supply, capacity and demand and other planning information.
augmentation	The process of upgrading the capacity or service potential of a transmission (or a distribution) pipeline.
Australian Wind Energy Forecasting System (AWEFS)	A system used by the Australian Energy Market Operator (AEMO) to produce wind generation forecasts ranging from five minutes ahead to two years ahead.
automatic access standard	In relation to a technical requirement of access, a standard of performance, identified in a schedule of Chapter 5 (of the NER) as an automatic access standard for that technical requirement, such that a plant that meets that standard would not be denied access because of that technical requirement. (See also minimum access standard and negotiated access standard.)
back assessment	The comparison of preceding maximum demand (MD) projections with actual (historical) MD values.
backcasting	Backcasting involves 'forecasting' historical maximum demands (MDs), which involves applying the current forecasting model to project values of seasonal MD that have already occurred, but were not used in deriving the forecasting model. Backcasting takes actual economic and climatic conditions and temperatures into account to produce a single point MD projection for each season for comparison with the actual (historical) seasonal MDs.
capacitive reactance	The component of a circuit element's impedance that is due to the establishment of an electric field. Current through the capacitive component is proportional to the differential of the voltage across that component. See also 'reactive power'.
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% POE scheduled and semi-scheduled maximum demand + minimum reserve level – committed demand-side participation.
capacity limited	A generating unit whose power output is limited.
Capital Deferral Benefit	A benefit deriving from the reduced capital costs resulting from being able to reduce (or defer) generation or transmission investment.
causer-pays methodology	A methodology used to allocate frequency control ancillary service (FCAS) costs. See also 'frequency control ancillary services (FCAS)'.
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.

Term	Definition
cleared supply	An estimate of the expected demand at the end of a dispatch interval. Calculated at the start of the dispatch interval, it is the sum of the: • generating unit dispatch targets within a region, and • net interconnector dispatch targets into a region.
coincidence factor	An expression of the degree of historical coincidence of the maximum demands (MDs) within different regions in the National Electricity Market (NEM), or between regional MDs and the NEM-wide MD.
committed project	A committed project is any new: • generation development or non-regulated transmission development that meets all five criteria specified by the Australian Energy Market Operator (AEMO) for a committed project – generation (see Chapter 5 of the ESOO for more information), or • regulated transmission augmentation that meets all four criteria specified by AEMO for a committed project – transmission.
compound average growth rate	The year-over-year growth rate over a specified period of time.
conceptual augmentation	A proposed transmission network augmentation option that could provide market benefits (possibly including Reliability Benefits). Conceptual augmentations may or may not be built in the future. The timing and value of these projects depends on the development of the electricity market. Conceptual augmentations do not satisfy the criteria for a committed project. See also 'committed project'.
connection assets	Those components of a transmission or distribution system which are used to provide connection services.
connection asset	The electricity transmission or distribution network components used to provide connection services (for example, 220/66 kV transformers).
connection point (electricity)	The agreed point of supply established between network service provider(s) and another registered participant, non-reregistered customer or franchise customer.
constrained	A limitation on the capability of a network, load, or a generating unit such that it is unacceptable to either transfer, consume or generate the level of electrical power that would occur if the limitation was removed.
constraint (electricity)	Any limitation on the operation of the transmission system that will give rise to unserved energy (USE) or to generation re-dispatch costs.
connection asset constraint	A constraint applying to an asset connecting the electricity transmission network to the distribution network.
constraint equation	The mathematical expression of a physical system limitation or requirement that must be considered by the central dispatch algorithm when determining the optimum economic dispatch outcome. See also 'binding constraint equation', 'FCAS constraint equation', 'invoked constraint equation', and 'network constraint equation'.
constraint value estimate	An electricity transmission network constraint's expected cost to the community, weighted by the probability of a contingency event occurring. This cost comprises load shedding and generation rescheduling (for example increased fuel cost).
constraint equation violation	Occurs when the requirements of a constraint equation are not met. Under some power system operating conditions it might not be feasible to meet the requirements of all invoked constraint equations simultaneously in the central dispatch process. Measured in megawatts (MW), the constraint equation violation represents the amount by which a constraint equation's requirements are exceeded.
consumer	See customer.
contestable augmentation	An electricity transmission network augmentation for which the capital cost is reasonably expected to exceed $10M and that can be constructed as a separate augmentation (i.e. the assets forming that augmentation are distinct and definable).
contingency event	An event affecting the power system, such as the failure or unplanned removal from operational service of a generating unit or transmission network element.
contingency services	Services provided by registered participants that enable the maintenance or restoration of power system security, or both. This includes, for example, actual active and reactive power capacities, which can be made available and used when a contingency event occurs.

Term	Definition
credible contingency event	A contingency event the Australian Energy Market Operator (AEMO) considers reasonably possible, given the circumstances in the power system.
critical contingency	The specific forced or planned outage that has the greatest potential to impact on the electricity transmission network at any given time.
customer (electricity)	A person who: • engages in the activity of purchasing electricity supplied through a transmission or distribution system to a connection point, and • is registered by AEMO as a customer under Chapter 2 (of the NGR).
damping torque	A stabilising force applied to the rotor of a generating unit, via the operation of excitation system controls and the electrical network that quickly reduces electrical power oscillations. See also 'rotor'
degree day	A commonly used temperature model for predicting gas demand for area/space heating.
demand	See electricity demand.
demand diversity	Referring to both intra and inter-regional demand diversity: • 'intra-regional' recognises that the maximum demands (MDs) at each connection point within a region might not occur at the same time, and the sum of the connection point MDs will exceed the regional MD, and • 'inter-regional' recognises that the MDs of different regions may occur at different times, and the sum of the individual regional MDs will exceed the total National Electricity Market (NEM) MD.
demand response aggregator (DRA)	An organisation contracted to facilitate and administer the provision of demand-side responses.
demand-side management	The act of administering electricity demand-side participants (possibly through a demand-side response aggregator).
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.
demand-side response aggregator	An organisation or agency for the provision and administration of electricity demand-side responses/participation.
discovered petroleum initially-in-place	The quantity of petroleum estimated, at a given date, contained in known accumulations prior to production.
dispatch algorithm	The algorithm used by the Australian Energy Market Operator (AEMO) to manage the central dispatch process. This algorithm is run before every dispatch interval. See also 'National Electricity Market Dispatch Engine (NEMDE)'.
dispatch instruction	An instruction issued by the Australian Energy Market Operator (AEMO): • to implement central dispatch, or • where AEMO has the power to give a direction.
dispatch interval	A period of five minutes.
dispatch targets	A particular dispatch interval's specified generating unit output and interconnector power flow targets.
dispatched load	The load which has been dispatched as part of central dispatch.
distribution losses	Electrical energy losses incurred in distributing electricity over a distribution network.
distribution network	A network which is not a transmission network.
distribution network service provider (DNSP)	A person who engages in the activity of owning, controlling, or operating a distribution system.
diversity	The lack of coincidence of peak demand across several sources of demand, such as residential, industrial and gas-fired generation.
effective degree day	A measure of coldness that includes temperature, sunshine hours, chill and seasonality. The higher the number, the colder it appears to be and the more energy that will be used for area heating purposes. EDD is used to model the daily gas demand-weather relationship.

Term	Definition
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 electrical power consumed by the consumer load • distribution and transmission losses, and • power station transformer losses and auxiliary loads. The ESOO reports demand as the average value over a 30-minute period.
embedded generating unit	A generating unit connected within a distribution network and not having direct access to the transmission network.
embedded generator	A generator who owns, operates or controls an embedded generating unit.
energy	See 'electrical energy'.
Energy Adequacy Assessment Projection (EAAP)	A quarterly report, produced by the Australian Energy Market Operator (AEMO), of 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). The first EAAP report is due on 31 March 2010.
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.
estimated ultimate recovery (EUR)	A term applied to any discovered or undiscovered petroleum accumulations to define potentially recoverable quantities under defined technical and commercial conditions. This includes quantities already produced (total of recoverable resources).
ex-ante	Before the event.
exempted generator	A generator exempted from the requirement to register in accordance with Clause 2.2.1 of the NER, and in accordance with the Australian Energy Market Operator's (AEMO) Generator Registration Guide.
FCAS constraint equation	A constraint equation that reflects the need to obtain sufficient frequency control ancillary services (FCAS). See also 'frequency control ancillary services (FCAS)'.
fault clearing control scheme	A protection system designed to isolate an electrical fault of a defined type within a particular area (referred to as a protection zone).
feedstock	Raw material required for an industrial process as opposed to fuel burnt or altered obtaining energy.
first-tier load	Electricity purchased at a connection point directly and in its entirety from the local retailer and which is classified as a first-tier load in accordance with Chapter 2 (of the NER).
flow path	Those elements of the electricity transmission networks used to transport significant amounts of electricity between generation centres and major load centres.
forced outage	An unplanned outage of an electricity transmission network element (transmission line, transformer, generator, reactive plant, etc).
franchise customer	A person who does not meet its local jurisdiction requirements to make it eligible to be registered by AEMO as a customer for a load.

Term	Definition
frequency control ancillary services (FCAS)	Those ancillary services concerned with balancing, over short intervals (shorter than the dispatch interval), the power supplied by generating units and the power consumed by loads. This imbalance is managed by monitoring the power system frequency.
front-end engineering and design (FEED)	An engineering process commonly undertaken to determine the engineering parameters of a construction or development, in terms of engineering design, route selection, regulatory and financial viability assessments, and environmental and native title clearance processes.
generating plant	In relation to a connection point, includes all equipment involved in generating electrical energy.
generating system	A system comprising one or more generating units and includes auxiliary or reactive plant that is located on the generator's side of the connection point and is necessary for the generating system to meet its performance standards.
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.
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 centre	A geographically concentrated area containing a generating unit or generating units with significant combined generating capability.
generation expansion plan	A plan developed using a special algorithm that models the extent of new entry generation development based on certain economic assumptions.
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.
generator auxiliary load	Load used to run a power station, including supplies to operate a coal mine (otherwise known as 'used in station load').
generator-terminal basis	A measure of demand at the terminals of a generating unit. This measure covers the entire output of the generating unit, and includes (in megawatts (MW)): • consumer load • transmission and distribution losses • generating unit auxiliary load, and • generator transformer losses.
gen-tailer	A business with both generation and retail portfolios.
greenfield	Land (as a potential industrial site) not previously developed or polluted.
Heating Degree Day	See Degree Day.
inductive reactance	The component of a circuit element's impedance that is due to the establishment of a magnetic field. Current through the inductive component is proportional to the integral of the voltage across that component. See also 'reactive power'.
installed capacity	The generating capacity (in megawatts (MW)) of (for example): • a single generating unit, or • a number of generating units of a particular type or in a particular area, or • 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.

Term	Definition
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.
initial reserves	Total discovered reserves at a given date, without taking into account the depletion of reserves due to production.
invoked constraint equation	A constraint equation that is active in central dispatch, and can influence the dispatch outcome.
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). Prior to 1 July 2009, the jurisdictional planning bodies were Powerlink Queensland, TransGrid, the Victorian Energy Networks Corporation (VENCorp), the Electricity Supply Industry Planning Council (ESIPC) and Transend Networks. The Australian Energy Market Operator (AEMO) now incorporates VENCorp and ESIPC, and undertakes the JPB function for Victoria. ElectraNet now undertakes the JPB function for South Australia.
Lack of Reserve (LOR) notice/Low Reserve Condition (LRC) notice	A notice to registered participants advising when reserves are projected to be or are below critical levels. See also 'Lack of Reserve 1 (LOR1)', 'Lack of Reserve 2 (LOR2)', 'Lack of Reserve 3 (LOR3)' and 'low reserve condition (LRC)'.
Lack of Reserve 1 (LOR1)	When, for the nominated period, the Australian Energy Market Operator (AEMO) considers there are insufficient short-term capacity reserves available. This capacity must be sufficient to provide complete replacement of the contingency capacity reserve when a critical single credible contingency event occurs in the nominated period.
Lack of Reserve 2 (LOR2)	When the Australian Energy Market Operator (AEMO) considers that the occurrence of a critical single credible contingency event is likely to require involuntary load shedding.
Lack of Reserve 3 (LOR3)	When the Australian Energy Market Operator (AEMO) considers that customer load (other than ancillary services or contracted interruptible loads) would be, or is actually being, interrupted automatically or manually in order to maintain or restore the security of the power system.
liquid fuelled generation	Generation that utilises liquid fuel (usually in the form of distillate, kerosene or fuel oil) as its primary fuel source.
Liquefied Natural Gas	Natural gas that has been converted to liquid form for ease of storage or transport. The Melbourne LNG storage facility is located at Dandenong.
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.
local network service provider	Within a local area, a network service provider to which that geographical area has been allocated by the authority responsible for administering the jurisdictional electricity legislation in the relevant participating jurisdiction.
local retailer	In relation to a local area, the customer who is: • a business unit or related body corporate of the relevant local network service provider, or • responsible under the laws of the relevant participating jurisdiction for the supply of electricity to franchise customers in that local area, or • if neither 1 or 2 is applicable, such other customer as AEMO may determine.
loss factor	A multiplier used to describe the electrical energy loss for electricity used or transmitted.
low reserve condition (LRC)	When the Australian Energy Market Operator (AEMO) considers that a region's reserve margin (calculated under 10% probability of exceedence (POE) scheduled and semi-scheduled maximum demand (MD) conditions) for the period being assessed is below the minimum reserve level (MRL).
marginal loss factor (MLF)	A multiplier used to describe the marginal electrical energy loss for electricity used or transmitted.
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 ancillary services	The ancillary services required by the Australian Energy Market Operator (AEMO) as part of the spot market, which include the services listed in Clause 3.11.2(a) of the NER. The prices of market ancillary services are established using the central dispatch process.
market customer (electricity)	A customer who has classified any of its loads as a market load and who is also registered by AEMO as a market customer under Chapter 2 (of the NER).
market generating unit	A generating unit whose sent-out generation is not purchased in its entirety by the local retailer or by a customer located at the same connection point and which has been classified as such in accordance with Chapter 2 (of the NER).
market generator	A generator who has classified at least one generating unit as a market generating unit in accordance with Chapter 2 (of the NER) and who is also registered by AEMO as a market generator under Chapter 2 (of the NER).
market load	A load that is settled through the spot market, and may also be classified as a scheduled load. Customers submit bids in relation to market loads to purchase electricity through the central dispatch process. They must be controllable according to dispatch instructions issued by the Australian Energy Market Operator (AEMO).
market network service provider (MNSP)	A network service provider who has classified any of its network services as a market network service in accordance with Chapter 2 (of the NER) and who is also registered by AEMO as a market network service provider under Chapter 2 (of the NER).
market non-scheduled (MNS) generating unit	A generating unit that: • sells energy into the energy spot market, and • is not scheduled by the Australian Energy Market Operator (AEMO) as part of central dispatch • has been classified as an MNS generating unit in accordance with Chapter 2 of the NER.
market scheduled (MS) generating unit	A generating unit that: • sells energy into the energy spot market • is scheduled by the Australian Energy Market Operator (AEMO) as part of central dispatch, and • has been classified as an MS generating unit in accordance with Chapter 2 of the NER.
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).
market price cap (MPC)	A price cap on regional reference prices as described in Clause 3.9.4 (of the NER). As at 1 December 2009, the market price cap was $10,000 / MWh with a planned increase to $12,500 / MWh from July 2010.
maximum daily quantity	Maximum daily quantity of gas supply or demand.
maximum demand (MD)	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 PASA in respect of the period from the 8th day after the current trading day to 24 months after the current trading day in accordance with Clause 3.7.2 (of the NER).
meter	A device that measures and records volumes and/or quantities of electricity or gas.
metering	The act of recording electricity and gas data (such as volume, peak, quality parameters etc) for the purpose of billing or monitoring quality of supply etc.
metering data	The data obtained from a metering installation, including energy data.
minimum access standard	In relation to a technical requirement of access, a standard of performance, identified in a schedule of Chapter 5 (of the NER) as a minimum access standard for that technical requirement, such that a plant that does not meet that standard will be denied access because of that technical requirement. (See also automatic access standard and negotiated access standard.)

Term	Definition
minimum reserve level (MRL)	The reserve margin (calculated under 10% probability of exceedence (POE) scheduled maximum demand (MD) conditions) required in a region to meet the Reliability Standard.
National Electricity Law	See National Gas Law.
National Electricity Market (NEM)	The wholesale exchange of electricity operated by the Australian Energy Market Operator (AEMO) under the NER.
National Electricity Objective (NEO)	To promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to: (a) price, quality, safety, reliability and security of supply of electricity, and (b) the reliability, safety and security of the national electricity system. This is defined in Section 7 of the National Electricity Law (NEL).
National Electricity Market Dispatch Engine (NEMDE)	The software that calculates the optimum economic dispatch of the National Electricity Market (NEM) every five minutes, subject to a number of constraint equations that reflect additional physical power system requirements. The software co-optimises the outcome of the energy spot market and the frequency control ancillary services (FCAS) market.
National Electricity Rules (NER)	See National Gas Law.
National Gas Law	The National Electricity Law and National Electricity Rules and the National Gas Law and National Gas Rules bring electricity and gas distribution under a national framework administered by the Australian Energy Regulator (AER).
National Gas Objective (NGO)	To promote efficient investment in, and efficient operation and use of, natural gas services for the long term interests of consumers of natural gas with respect to price, quality, safety, reliability and security of supply of natural gas.
National Gas Rules (NGR)	See National Gas Law.
National Transmission Network Development Plan (NTNDP)	An annual report to be produced by the Australian Energy Market Operator (AEMO) that replaces the existing National Transmission Statement (NTS) from December 2010. Having a 20-year outlook, the NTNDP will identify transmission and generation development opportunities for a range of market development scenarios, consistent with addressing reliability needs and maximising net market benefits, while appropriately considering non-network options.
National Transmission Statement (NTS)	An AEMO report replacing the Annual National Transmission Statement (ANTS) for 2009 only. The National Transmission Network Development Plan (NTNDP) replaces the NTS from December 2010.
native demand	The electricity demand supplied by scheduled, semi-scheduled, and significant non-scheduled generating units. Native demand is measured on a generator-terminal basis. For a region, the measure includes the output of scheduled, semi-scheduled, and significant non-scheduled generating units within the region plus net imports (imports into the region minus net exports from the region). See also significant non-scheduled generating unit and electricity demand This term is included in this Glossary to provide continuity with previous Electricity Statement of Opportunities (ESOO) documents. Native demand is now referred to as maximum demand (MD).
native energy	The electrical energy supplied by scheduled, semi-scheduled, and significant non-scheduled generating units. Native energy is measured on a sent out basis. For a region, the measure includes the output of scheduled, semi-scheduled, and significant non-scheduled generation units within the region plus net imports into the region (imports into the region minus exports from the region). The term is included in this Glossary to provide continuity with previous Electricity Statement of Opportunities (ESOO) documents. Native energy is now referred to as energy.
negotiated access standard	In relation to a technical requirement of access for a particular plant, an agreed standard of performance determined in accordance with Clause 5.3.4A (of the NER) and identified as a negotiated access standard for that technical requirement in a connection agreement. See also 'minimum access standard' and 'automatic access standard'.

Term	Definition
net import limit	Net import limits are: • equal to the assumed net regional imports arising from the minimum reserve level (MRL) calculations • necessary to ensure consistency between the calculation of MRLs and the assessment of reserve margins (as MRLs need to be met without violating the net import limits), and • only used in the Medium-term Projected Assessment of System Adequacy (Medium-term PASA or MT PASA), Short-term Projected Assessment of System Adequacy (Short-term PASA or ST PASA), and the supply-demand outlook in Chapter 2. The net import limits are not included in central dispatch and do not limit actual interconnector power flows.
net regional import	The total interconnector flow into a region minus the interconnector flow out of a region.
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 congestion	When a transmission network cannot accommodate the dispatch of the least-cost combination of available generation to meet demand.
network control ancillary service	A service identified in Clause 3.11.4(a) (of the NER) which provides AEMO with a capability to control the real or reactive power flow into or out of a transmission network in order to: • maintain the transmission network within its current, voltage or stability limits following a credible contingency event, or • enhance the value of spot market trading in conjunction with the central dispatch process.
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.
network limit	Defines the power system's secure operating range. Network limits also take into account equipment/network element ratings. See also 'ratings'.
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 limit equation	Describes the capability to transmit power through a particular portion of the network as a function of: • generating unit outputs • interconnector flows • transmission equipment ratings • demand at one or more connection points, and • equipment status or operating mode. The set of all network limit equations fully describes a network's capability. The Australian Energy Market Operator (AEMO) translates network limit equations into network constraint equations for use in the central dispatch process. See also 'constraint equation'.
network service	Transmission service or distribution service associated with the conveyance, and controlling the conveyance, of electricity through the network.
network service provider	A person who engages in the activity of owning, controlling or operating a transmission or distribution system and who is registered by AEMO as a network service provider under Chapter 2 (of the NER).
network support agreement (NSA)	An agreement between a network service provider and a market participant or any other person providing network support services to improve network capability by providing a non-network alternative to a network augmentation.

Term	Definition
non-coincident peak day demand	A given customer's (or group of customers') gas demand peak day. This does not necessarily occur at the same time as the system demand peak day.
non-contestable augmentation	Electricity transmission network augmentations that are not considered to be economically or practically classified as contestable augmentations.
non-credible contingency	Any planned or forced outage for which the probability of occurrence is considered very low. For example, the coincident outages of many transmission lines and transformers, for different reasons, in different parts of the electricity transmission network.
non-market ancillary services	Network control ancillary services (NCAS), reactive power ancillary services (RPAS) and system restart ancillary services (SRAS). These services are delivered under agreements entered into with the Australian Energy Market Operator (AEMO) following a call for offers made in accordance with Clause 3.11 of the NER.
non-market generating unit	A generating unit whose sent out generation is purchased in its entirety by the local retailer or by a customer located at the same connection point and which has been classified as such in accordance with Chapter 2 (of the NER).
non-market generator	A generator who has classified a generating unit as a non-market generating unit in accordance with Chapter 2 (of the NER).
non-market non-scheduled (NMNS) generating unit	A generating unit that: • sells its entire output directly to a local retailer or customer at the same connection point under a power purchase agreement (not through the spot market), and • is not scheduled by the Australian Energy Market Operator (AEMO) as part of central dispatch, and • has been classified as an NMNS generating unit in accordance with Chapter 2 of the NER.
non-market scheduled (NMS) generating unit	A generating unit that: • sells its entire output directly to a local retailer or customer at the same connection point under a power purchase agreement (not through the spot market), and • is scheduled by the Australian Energy Market Operator (AEMO) as part of central dispatch, and • has been classified as an NMS generating unit in accordance with Chapter 2 of the NER.
non-network option	An option intended to relieve a limitation without modifying or installing network elements. Typically, non-network options involve demand-side participation (DSP) (including post contingent load relief) and new generation on the load side of the limitation.
non-registered customer	A person who: • purchases electricity through a connection point with the national grid other than from the spot market, and • is eligible to be registered by AEMO as a customer and to classify the load described in (1) as a first-tier load or a second-tier load, but is not so registered.
non-scheduled generating system	A generating system comprising non-scheduled generating units.
non-scheduled generating unit	A generating unit that is not scheduled by the Australian Energy Market Operator (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).
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).
normalised wind trace	Used in market stimulations to determine the maximum available wind farm generation capacity for each dispatch interval. Normalised wind traces were developed using: • wind speed data from the Australian Bureau of Meteorology to produce wind speed traces, and • wind farm turbine characteristics (power curves) to convert wind speed traces into wind generation output availability traces.

Term	Definition
operating cost benefit	A benefit deriving from reduced fuel, operating and maintenance costs, indicating reduced operating costs.
outage constraint equation	A constraint equation invoked when an outage has occurred due to maintenance or a contingency event. See also 'system normal constraint equation' and 'invoked constraint equation'.
over voltage	A condition when the operating voltage of network components is above their nominated operation limit.
overload capacity	A measure of a generating unit's ability to generate more electricity than its registered capacity for a given period of time.
own price elasticity	The proportional change in electrical energy consumption in response to a proportional change in retail electricity price.
participant	A person registered with AEMO in accordance with the NGR (Victorian gas industry).
petajoule	Petajoule (PJ), SI unit, 1 PJ equals $1x10^{15}$ Joules. Also PJ/yr or petajoules per year.
pipeline	A pipe or system of pipes for or incidental to the conveyance of gas and includes a part of such a pipe or system.
pipeline injections	The injection of gas into a pipeline.
pipeline throughput	The amount of gas that is transported through a pipeline.
planning criteria	Criteria intended to enable the jurisdictional planning bodies (JPBs) to discharge their obligations under the NER and relevant regional transmission planning standards. The JPBs must consider their planning criteria when assessing the need to increase network capability.
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.
possible reserves (3P reserves)	Estimated quantities which have a chance of being discovered under favourable circumstances.
post-contingent	The timeframe after a power system contingency occurs.
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.
power system security	The safe scheduling, operation and control of the power system on a continuous basis in accordance with the principles set out in Clause 4.2.6 (of the NER).
post-contingent	The timeframe after a power system contingency occurs.
pre-contingent	The timeframe before a power system contingency occurs.
pre-dispatch	Forecast of dispatch performed one day before the trading day on which dispatch is scheduled to occur.
present value (PV)	The value of a future cash flow expressed in today's dollars, and calculated using a particular discount rate. Present value calculations provide a means to meaningfully compare cash flows at different times.
price elasticity	A measure of the proportional change in demand (for a commodity) in response to a proportional change in price.
prior outage conditions	A weakened electricity transmission network state where a transmission element is unavailable for service due to either a forced or planned outage.

Term	Definition
probable reserves (2P reserves)	The estimated quantities of petroleum, which with a reasonable probability of being produced under existing economic and operating conditions.
probability of exceedence (POE) maximum demand	The probability, as a percentage, that a maximum demand (MD) level will be met or exceeded (for example, due to weather conditions) in a particular period of time. For example, for a 10% POE MD for any given season, there is a 10% probability that the corresponding 10% POE projected MD level will be met or exceeded. This means that 10% POE projected MD levels for a given season are expected to be met or exceeded, on average, 1 year in 10.
probability of exceedence (POE) (electricity)	The probability that a forecast electricity maximum demand figure will be exceeded. For electricity, a forecast 10% POE maximum demand figure will, on average, be exceeded only 1 year in every 10.
production	The cumulative quantity of petroleum recovered at a given date.
proposed project	All generation project proposals that have come to the Australian Energy Market Operator's (AEMO) attention that are not committed. Proposed projects are further classified as either advanced proposals or publicly announced proposals.
prospective resources	Quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations through future development projects.
proved reserves (1P reserves)	The estimated quantitites of petroleum resources, which with a reasonable level of certainty, are recoverable in future years from known reservoirs under existing economic and operating conditions.
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.
range of uncertainty	A range of estimated quantities potentially recoverable from an accumulation by a project.
ratings	Describes an aspect of a network element's operating parameters, including categories like current-carrying capability, maximum voltage rating, and maximum fault level interrupting and withstand capability. Network elements must always be operated within their ratings. Network elements may have ratings that are dependant upon time duration (such as short-term current-carrying capacity).
reactive energy	A measure, in varhour-(varh), of the alternating exchange of stored energy in inductors and capacitors, which is the time-integral of the product of voltage and the out-of-phase component of current flow across a connection point.
reactive power	The rate at which reactive energy is transferred. Reactive power, which is different to active power, is a necessary component of alternating current electricity. In large power systems it is measured in MVAr (1,000,000 volt-amperes reactive). It is predominantly consumed in the creation of magnetic fields in motors and transformers and produced by plant such as: • alternating current generators • capacitors, including the capacitive effect of parallel transmission wires, and • synchronous condensors. Management of reactive power is necessary to ensure network voltage levels remain within required limits, which is in turn essential for maintaining power system security and reliability.
regional reference node	The reference point (or designated reference node) for setting a region's spot price. The current regions and their reference nodes are: • Queensland - South Pine Substation 275 kV bus • New South Wales - Sydney West Substation 330 kV bus • Tasmania – George Town 220 kV bus • Victoria - Thomastown Terminal Station 66 kV bus, and • South Australia - Torrens Island Power Station 66 kV bus.
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 capacity	In relation to a generating unit, the nominal megawatt (MW) capacity of the generating unit registered with the Australian Energy Market Operator (AEMO).

Term	Definition
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.
regulated interconnector	An interconnector which is referred to in Clause 11.8.2 (of the NER) and is subject to transmission service regulation and pricing arrangements in Chapter 6A (of the NER).
regulatory investment test for transmission (RIT-T)	The test developed and published by the AER in accordance with clause 5.6.5B, as in force from time to time, and includes amendments made in accordance with clause 5.6.5B.
Regulatory Test	The test promulgated by the Australian Energy Regulator (AER) to identify the most cost-effective option for supplying electricity to a particular part of the network. The test may also compare a range of alternative projects, including, but not limited to, new generation capacity, new or expanded interconnection capability, and transmission network augmentation within a region, or a combination of these. After 1 August 2010, projects will be assessed under the RIT-T (subject to transitional arrangements).
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 the Australian Energy Market Operator (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 benefit	A benefit deriving from improved customer reliability as measured by reduced unserved energy (USE). See also 'unserved energy (USE)'.
reliability of supply	The likelihood of having sufficient capacity (generation or demand-side participation (DSP) or both) to meet demand. See also 'electricity demand'.
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.
remaining reserves	Reserves at a given date, taking into account the depletion of reserves due to production.
reserve	See 'reserve margin'.
reserve deficit	The amount by which a region's reserve margin falls below its (specified) minimum reserve level (MRL).

Term	Definition
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.
reserves	Quantities of petroleum anticipated to be commercially recoverable from known accumulations from a given date under defined conditions.
reserves to production ratio (RP)	The remaining amount of petroleum, expressed in years.
retailer	Those selling the bundled product of energy services to the customer.
routine augmentation	Transmission augmentations that do not meet the criterion for committed projects, but that are likely to proceed, being routine in nature.
runback	A controlled reduction in the flow of electricity in a given network element, usually in association with a specific event. Murraylink has a runback system that rapidly reduces its power flow in response to the operation of an associated protection system.
satisfactory operating state	Operation of the electricity transmission network such that all plant is operating at or below its rating (whether the continuous or (where applicable) short-term rating).
scale efficient network extensions (SENE)	A development model for connecting clusters of generation, proposed by the Australian Energy Market Commission (AEMC) as part of its review of energy market frameworks in light of climate change policies.
scenario	A consistent set of assumptions used to develop forecasts of demand, transmission and supply.
scheduled demand	That part of the electricity demand supplied by scheduled generating units. Scheduled demand is measured on a generator-terminal basis. For a region, the measure includes the output of scheduled generating units within the region plus net imports (imports into the region minus exports from the region).
scheduled energy	The electrical energy requirement supplied by scheduled generating units. Scheduled energy is measured on a sent-out basis. For a region, the measure includes the output of scheduled generating units within the region plus net imports (imports into the region minus exports from the region).
scheduled and semi-scheduled demand	That part of the electricity demand supplied by scheduled and semi-scheduled generating units. Scheduled and semi-scheduled demand is measured on a generator-terminal basis. For a region, the measure includes the output of scheduled and semi-scheduled generating units within the region plus imports into the region minus exports from the region attributable to semi-scheduled generation.
scheduled and semi-scheduled demand	That part of the electricity demand supplied by scheduled and semi-scheduled generating units. Scheduled and semi-scheduled demand is measured on a generator-terminal basis. For a region, the measure includes the output of scheduled and semi-scheduled generating units within the region plus imports into the region minus exports from the region attributable to semi-scheduled generation.
scheduled and semi-scheduled energy	The electrical energy requirement supplied by scheduled and semi-scheduled generating units. Scheduled and semi-scheduled energy is measured on a sent-out basis. For a region, the measure includes the output of scheduled and semi-scheduled generating units within the region plus net imports (imports into the region minus exports from the region).
scheduled generating unit	A generating unit that: • has its output controlled through the central dispatch process, and • is 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).

Term	Definition
scheduled load	(a) A market load which has been classified by AEMO in accordance with Chapter 2 (of the NER) as a scheduled load at the market customer's request. Under Chapter 3 (of the NER), a market customer may submit dispatch bids in relation to scheduled loads. (b) For the purposes of Chapter 3 (of the NER) and rule 4.9, two or more scheduled loads referred to in paragraph (a) that have been aggregated in accordance with Clause 3.8.3 (of the NER).
scheduled network service	(a) A network service which is classified as a scheduled network service in accordance with Chapter 2 (of the NER). (b) For the purposes of Chapter 3 (of the NER) and rule 4.9, two or more scheduled network services referred to in paragraph (a) that have been aggregated in accordance with Clause 3.8.3 (of the NER).
scheduling	The process of scheduling nominations and increment/decrement offers, which AEMO is required to carry out in accordance with the NGR, for the purpose of balancing gas flows in the transmission system and maintaining the security of the transmission system.
SEA Gas Interconnect	The interconnection between the SEA Gas pipeline and the PTS at Iona.
SEA Gas Pipeline	The 680 km pipeline from Iona to Adelaide, principally constructed to ship gas from Victoria to South Australia.
second-tier load	Electricity purchased at a connection point in its entirety other than directly from the local retailer or the spot market and which is classified as a second-tier load in accordance with Chapter 2 (of the NER).
secure operating state	Operation of the electricity transmission network such that should a credible contingency occur, the network will remain in a 'satisfactory' state.
semi-scheduled demand	That part of the electricity demand supplied by semi-scheduled generating units. Semi-scheduled demand is measured on a generator-terminal basis. For a region, the measure includes the output of semi-scheduled generating units within the region.
semi-scheduled energy	The electrical energy requirement supplied by semi-scheduled generating units. Semi-scheduled energy is measured on a sent-out basis. For a region, the measure includes the output of semi-scheduled generating units within the region.
semi-scheduled generating system	A generating system comprising semi-scheduled generating units.
semi-scheduled generating unit	A generating unit: • with intermittent output • with a total capacity of 30 megawatts (MW) or greater, and • that 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).
sent-out basis	A measure of demand or energy (in megawatts (MW) and megawatt hours (MWh), respectively) at the connection point between the generating system and the network. This measure includes consumer load and transmission and distribution losses.
settlements residue	Any surplus or deficit of funds retained by AEMO upon completion of settlements to all market participants in respect of a trading interval.
settlements residue auction (SRA)	Auctions run by the Australian Energy Market Operator (AEMO) to sell the rights to the settlements residue associated with inter-regional transfers. Only certain classifications of participants may participate in the auctions. Participants may use the settlements residue for hedging and underwriting inter-regional trading in electricity.
short run marginal cost (SRMC)	The increase in costs for an incremental increase in output. This includes the additional cost of: • fuel required, and • non-fuel variable costs like maintenance, water, chemicals, ash disposal, etc.
Short-term Projected Assessment of System Adequacy (Short-term PASA or ST PASA)	The PASA in respect of the period from 2 days after the current trading day to the end of the 7th day after the current trading day inclusive in respect of each trading interval in that period.

Term	Definition
significant non-scheduled generating unit	Refers to all: • market non-scheduled (MNS) generating units, and • non-market non-scheduled (NMNS) generating units and generating units exempted from registration (with an aggregate capacity greater than 1 MW), for which the Australian Energy Market Operator (AEMO) and the jurisdictional planning bodies (JPBs) have sufficient data to enable the development of energy and maximum demand (MD) projections.
South West Pipeline	The 500 mm pipeline from Lara (Geelong) to Iona.
special participant	A system operator or a distribution system operator.
spike loads	A short duration peak in gas demand.
spot market	Wholesale trading in electricity is conducted as a spot market. The spot market: • enables the matching of supply and demand • is a set of rules and procedures to determine price and production levels, and • is managed by the Australian Energy Market Operator (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.
Statement of Opportunities	The (gas or electricity) Statement of Opportunities published annually by AEMO.
summer	In terms of the electricity industry, December to February of a given fiscal year.
supervisory control and data acquisition (SCADA)	Equipment used to collect power system data. SCADA data: • may be transmitted to or from electrical substations, power stations, and control centres, and • is normally collected for a variety of power system quantities at rates of once every two to four seconds (depending on the quantities measured). The equipment can also be used to send or receive control signals for power system equipment and generating units. The data and control signals are used to manage the operation of the power system from control centres.
supply	The delivery of electricity.
system capacity	The maximum demand that can be met on a sustained basis over several days given a defined set of operating conditions. System capacity is a function of many factors and accordingly a set of conditions and assumptions must be understood in any system capacity assessment. These factors include: • load distribution across the system • hourly load profiles throughout the day at each delivery point • heating values and the specific gravity of injected gas at each injection point • initial linepack and final linepack and its distribution throughout the system • ground and ambient air temperatures • minimum and maximum operating pressure limits at critical points throughout the system, and • powers and efficiencies of compressor stations.
system coincident peak day	The day of highest system demand (gas). See also system demand.
system demand	Demand from Tariff V (residential, small commercial and industrial customers nominally consuming less than 10 TJ of gas per annum) and Tariff D (large commercial and industrial customers nominally consuming more than 10 TJ of gas per annum). It excludes gas-fired generation demand, exports, and gas withdrawn at Iona.
system normal constraint	A constraint that arises even when all electricity plant is available for service.
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).

Term	Definition
supply-demand outlook	The future state of supply's ability to meet projected demand.
synchronous condensor mode	Operation of a synchronous machine to generate or absorb reactive power, enabling control of system voltage.
system normal constraint equation	Constraint equations used in central dispatch when: • all transmission elements are in service, or • the network is operating in its normal network configuration.
system restart ancillary services (SRAS)	The set of contracted restart services procured by the Australian Energy Market Operator (AEMO) to facilitate the supply of sufficient energy to enable the orderly restart of other (large) generating units.
Tasmanian Capacity Reserve Standard	The standard by which Tasmanian reserve adequacy was assessed prior to Tasmania's entry into the NEM. The standard was set by the Tasmanian Reliability and Network Planning Panel, and was specified as the greater of the level: • required to ensure that there was a reasonable probability that all single credible contingency events could be sustained without involuntary load shedding, and • calculated to achieve a reliability standard such that unserved energy in Tasmania would not exceed targets appropriate for Tasmania's transition into the NEM.
Tasmanian Gas Pipeline	The pipeline from VicHub (Longford) to Tasmania.
terajoule	Terajoule (TJ). An SI unit, 1 TJ equals $1x10^{12}$ Joules.
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.
total petroleum initially-in-place	The quantity of petroleum estimated to exist originally in naturally occurring accumulations.
trader	Anyone who wishes to participate in a settlements residue auction (SRA) and is not already registered with the Australian Energy Market Operator (AEMO) as a market customer or a generator must register as a trader.
trading interval	A 30 minute period ending on the hour (EST) or on the half hour and, where identified by a time, means the 30 minute period ending at that time.
transmission losses	Electrical energy losses incurred in transporting electrical energy through a transmission system.
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.
transmission pipeline	A pipeline that is not a distribution pipeline.
transmission pipeline owner	A person who owns or holds under a lease a transmission pipeline which is being or is to be operated by AEMO.
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.
transmission system (gas)	The transmission pipelines or system of transmission pipelines forming part of the 'gas transmission system' as defined under the Gas Industry Act.
tri-generation	A generation system that produces at least three different forms of energy from the primary energy source: hot water, chilled water, and power generation (electrical energy).

Term	Definition
Unconstrained Intermittent Generation Forecast (UIGF)	A forecast produced by the Australian Energy Market Operator's (AEMO) Australian Wind Energy Forecasting System (AWEFS) for an intermittent generating unit, considering: • generating unit (turbine) availability • the availability of the energy required for the unit's energy conversion process (for example wind, solar, or tidal), and • assuming no network limitations. The UIGF applies as an upper dispatch limit for an intermittent generating unit.
under excitation limit	A control function performed by the excitation systems of synchronous machines in a power plant, usually to prevent unstable operation of a generating unit. See also 'over excitation limit'.
undiscovered petroleum initially-in-place	The quantity of petroleum estimated, as of a given date, to be contained within accumulations yet to be discovered.
unrecoverable	The portion of discovered or undiscovered petroleum initially-in-place quantities, which is estimated as of a given date, deemed not recoverable by future development projects. A portion of these quantities may become recoverable in the future as commercial circumstances change or technological developments occur.
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'.
Value of Customer Reliability (VCR)	A measure of the cost of unserved energy used in Regulatory Test assessments for planned augmentations for the Victorian electricity transmission system [1]. The VCR is determined through a customer survey approach that estimates direct end-user customer costs incurred from power interruptions at the sector and State levels. An assessment for the Victorian region, while AEMO uses a VCR of $55,000/MWh in Victoria, there is no nationally agreed VCR.
violated constraint equation	A constraint equation for which the network attributes for a particular dispatch solution do not satisfy the equation's requirement.
voltage instability	An inability to maintain voltage levels within a desired operating range. For example, in a 3-phase system, voltage instability can lead to all three phases dropping to unacceptable levels or even collapsing entirely.
voltage unbalance	A quality of supply problem in a 3-phase system, voltage unbalance occurs when the three phases are not equal in magnitude or equidistant (120 degrees) in phase, and can cause plant failures, typically through overheating.
winter	In terms of the electricity industry, June to August of a given calendar year.

Company names

This section lists the full name and Australian Business Number (ABN) number of companies referred to in this document.

Company	Full company name	ABN
Access Economics	Access Economics Pty Ltd	82 113 621 361
Acciona Energy	Acciona Energy Oceania Pty Ltd	98 102 345 719
ACIL Tasman	ACIL Tasman Pty Ltd	68 102 652 148
AEMC	Australian Energy Market Commission	49 236 270 144

Company	Full company name	ABN
AEMO	Australian Energy Market Operator	92 072 010 327
AGL Energy	AGL Energy Ltd	74 115 061 375
Alinta Energy	Alinta Energy Pty Ltd	16 108 664 151
Altona Resources	Altona Resources Ltd	73 107 555 117
Aurora Energy Tamar Valley Power	Aurora Energy Tamar Valley Power Pty Ltd	29 123 391 613
Australian Academy of Technological Science and Engineering	Australian Academy of Technological Science and Engineering limited	008 520 394
Australian National Low Emission Coal Research And Development	Australian National Low Emission Coal Research And Development ltd	135 762 533
Australian Petroleum Production and Exploration Association (APPEA)	Australian Petroleum Production & Exploration Association limited	000 292 713
Australia Pipeline Industry Association (APIA)	Australia Pipeline Industry Association limited	098 754 324
Babcock & Brown Power	Babcock & Brown Power Pty Ltd	67 116 665 608
Babcock & Brown Wind Partners	Babcock & Brown Wind Partners Ltd	39 105 051 616
Carbon Market Economics (CME)	Carbon Market Economics PTY LTD	128 476 415
Cathedral Rocks Wind Farm	Cathedral Rocks Wind Farm Pty Ltd	87 107 113 708
Clean Energy Council	Clean Energy Council limited	127 102 443
Commonwealth Scientific and Industrial Research Organisation (CSIRO)	CSIRO	126447489
Country Energy	Country Energy	37 428 185 226
CS Energy	CS Energy Ltd	54 078 848 745
CSR	CSR Ltd	90 000 001 276
CRA International	CRA International Pty Ltd	12 095 147 738
Delta Electricity	Delta Electricity Australia Pty Ltd	26 074 408 923
Diamond Energy	Diamond Energy Pty Ltd	97 107 516 334
Eastern Star	Eastern Star Gas Limited	29 094 269 780
Ecogen	Ecogen Energy Pty Ltd	86 086 589 611
EDL	Energy Developments Ltd	84 053 410 263
ElectraNet	Electranet Pty Ltd	41 094 482 416
Energy Australia	Energy Australia	67 505 337 385
Energy Brix	Energy Brix Australia Corporation Pty Ltd	79 074 736 833
Energy Networks Association (ENA)	Energy Networks Association limited	106 735 406
Energy Response	Energy Response Pty Ltd	49 104 710 278
Energy Retailers Association of Australia (ERAA)	Energy Retailers Association of Australia limited	103 742 605
Energy Supply Association of Australia	Energy Supply Association of Australia limited	052 416 083
Energy Users Association of Australia (EUAA)	Energy Users Association of Australia	814 086 707
Envirogen	Envirogen Pty Limited	95 088 169 135

Company	Full company name	ABN
Epuron	EPURON Pty Ltd	70 104 503 380
Eraring Energy	Eraring Energy	31 357 688 069
ERM Power	ERM Power Pty Ltd	28 122 259 223
ESCOSA	The Essential Services Commission of South Australia	91 774 807 273
Eureka Funds Management	Eureka Funds Management Administration	62 107 346 903
Flinders Power	Flinders Operating Services Pty Ltd	36 094 130 837
Gunns	Gunns Ltd	29 009 478 148
The GPT Group	GPT RE Limited	27 107 426 504
HRL	HRL Ltd	89 061 930 756
Hydro Tasmania	Hydro-Electric Corporation	48 072 377 158
IES	Intelligent Energy Systems	51 002 572 090
IMO	Independent Market Operator	95 221 850 093
Inifigen Energy	Infigen Energy Limited	39 105 051 616
Infratil Energy	Infratil Energy Australia Pty Ltd	87 115 291 042
International Power	International Power (Australia) Pty Ltd	59 092 560 793
Investec	Investec Bank (Australia) Limited	55 071 292 594
KEMA Consulting	KEMA Consulting, Inc.	61 074 914 579
KPMG	KPMG Australia	51 194 660 183
LMS Generation	LMS Generation Pty Ltd	39 059 428 474
Loy Yang Marketing Management Company	Loy Yang Marketing Management Company Pty Ltd	19 105 758 316
McLennan Magasanik Associates (MMA)	McLennan Magasanik Associates	33 579 847 254
Macquarie Generation	Macquarie Generation	18 402 904 344
Marubeni Corporation	Marubeni Australia Power Services Pty Ltd	40 064 462 111
Millmerran	Millmerran Energy Trader Pty Ltd	23 084 923 973
Minerals Council of Australia	Minerals Council of Australia	008 455 141
National Generators Forum	National Generators Forum limited	113 331 623
NIEIR	National Institute of Economic and Industry Research Pty Ltd	72 006 234 626
NP Power	N.P.Power Pty Ltd	82 094 423 006
Origin Energy	Origin Energy Electricity Ltd	33 071 052 287
Pacific Hydro	Pacific Hydro Pty Ltd	31 057 279 508
Powerlink Queensland	Queensland Electricity Transmission Corporation Ltd	82 078 849 233
Progressive Green	Progressive Green Pty Ltd	27 130 175 343
QGC	Queensland Gas Company Ltd	11 089 642 553
Redbank Power	Redbank Project Pty Ltd	34 075 222 561
Renewable Power Ventures	Renewable Power Ventures Pty Ltd	25 102 696 159
Rio Tinto	Rio Tinto Aluminium (Holdings) Limited	37 004 502 694
ROAM Consulting	Roam Consulting Pty Ltd	54 091 533 621
Roaring 40s	Roaring 40s Renewable Energy Pty Ltd	63 111 996 313
Rocky Point Green Power	Rocky Point Power Project Pty Ltd	21 117 462 889
Santos	Santos Ltd	80 007 550 923

Company	Full company name	ABN
Solar Systems	Solar Systems Pty Ltd	43 090 609 868
Snowy Hydro	Snowy Hydro Ltd	17 090 574 431
Southern Hydro	Southern Hydro Pty Ltd	89 088 976 327
SP AusNet	SP Australia Networks (Transmission) Ltd	48 116 124 362
Stanwell Corporation	Stanwell Corporation Ltd	37 078 848 674
Strike Oil	Strike Oil Ltd	59 078 012 745
Synergen	Synergen Power Pty Ltd	66 092 560 819
Tarong Energy	Tarong Energy Corporation Ltd	52 078 848 736
TME	TME Australia Pty Ltd	71 094 361 850
Transend Networks	Transend Networks Pty Ltd	57 082 586 892
Transfield Services	Transfield Services Infrastructure Ltd	31 106 617 332
TransGrid	TransGrid	19 622 755 774
TRUenergy	Truenergy Pty Ltd	99 086 014 968
TrustPower	TrustPower Australia Holdings Pty Ltd	15 101 038 331
Union Fenosa	Union Fenosa Wind Australia	74 130 542 031
Veolia Environmental Services	Veolia Environmental Services Australia PTY Ltd	20 051 316 584
Vic Power	State Electricity Commission of Victoria	58 155 836 293
Western Power	Western Power Corporation	38 362 983 875
West Wind	WestWind Energy Pty Ltd	94 109 132 201
Wind Farm Development	Wind Farm Developments Pty Ltd	87 100 010 348
Windlab Systems	Windlab Systems Pty Ltd	26 104 461 958
Wind Power Pty Ltd	Wind Power Pty Ltd	68 117 035 766
Wind Prospect	Wind Prospect Pty Ltd	22 091 885 924