Statement of Opportunities

June 2011

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Executive Summary

The Statement of Opportunities Report (SOO) is published annually by the Independent Market Operator (IMO). The SOO provides information on existing supply capacity and future electricity demand to current and potential participants in the Wholesale Electricity Market (WEM).

The SOO is a key element of the Reserve Capacity Mechanism (RCM) - the mechanism through which the WEM secures capacity to meet peak demand. The RCM has provided positive outcomes for the Western Australian economy, with more than 2,500 MW of new generation plant and DSM being committed over the last 6 years. Not only is this investment helping to ensure reliability of supply, but the increasing number of Market Participants is providing greater competition in the market.

The SOO focuses on opportunities for investment in generation capacity and Demand Side Management (DSM) over the medium term. The 2011 SOO places emphasis on the 2013/14 Capacity Year, setting the amount of capacity required to be available by 1 October 2013, a key parameter of the RCM. Information is also provided on forecast maximum demand and electricity consumption within the South West interconnected system (SWIS) through to October 2022.

In addition, the SOO provides stakeholders with:

- a detailed commentary on the current status of the transmission network, including the Generation Connection Capacity Map developed by Western Power in 2010 (see Section 7.2 and Appendix 10);
- a discussion on the availability of fuel for generation (see Section 7.3); and
- information on key areas of reform in the WEM (see Chapter 7).

Key Results for 2013/14

- The Reserve Capacity Target for 2013/14 is set at 5,312 MW. This is based on the one-in-ten year peak demand forecast with additional allowances for intermittent loads, unplanned plant outages (8.2% of the peak demand forecast) and provision of frequency control services.
- Forecast average annual growth through to 2021/22 is 3.8% for peak demand and 2.9% for energy.
- The IMO anticipates that 5,996 MW of generation and DSM capacity, either existing or committed with Capacity Credits for 2012/13, will continue in service through to 2013/14.
- The existing in-service or committed facilities represent a surplus of 684 MW of capacity above the Reserve Capacity Target for 2013/14, prior to the introduction of any new capacity for that year.

Expressions of Interest for New Capacity

In May 2011 the IMO completed its annual Expression of Interest process to identify new sources of generation and DSM capability for 2013/14.

Eight Expressions of Interest were received, covering a total potential Reserve Capacity of 337.25 MW. The amounts of each type of capacity are shown in Table A.

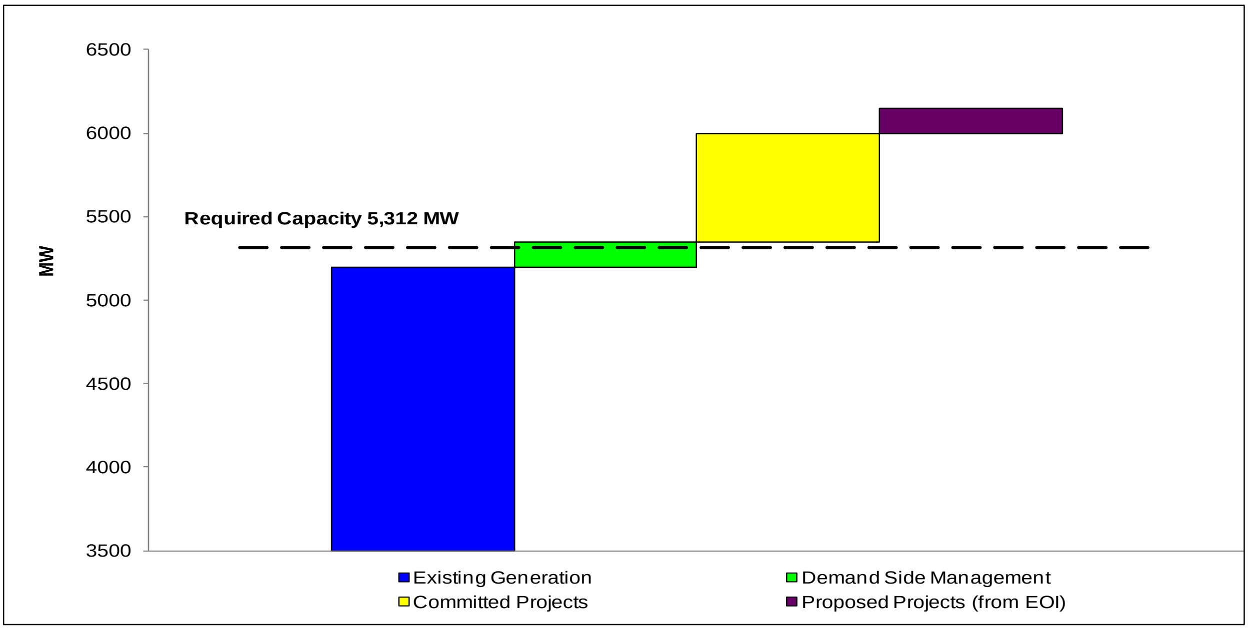
Table A – Summary of 2011 Expressions of Interest

Type of Capacity in the EOI process	Aggregate Potential Reserve Capacity (MW)
Thermal	180
Renewable	56.65
DSM	100.6
Total	**337.25**

The IMO estimates that 156 MW of this capacity could potentially be available to meet demand in the 2013/14 Capacity Year. Given the quantities of existing capacity, committed projects and anticipated new capacity, the IMO considers it likely that there will be more than sufficient capacity for the 2013/14 Reserve Capacity Year.

Figure A illustrates the expected status of capacity in the SWIS in the 2013/14 Reserve Capacity Year.

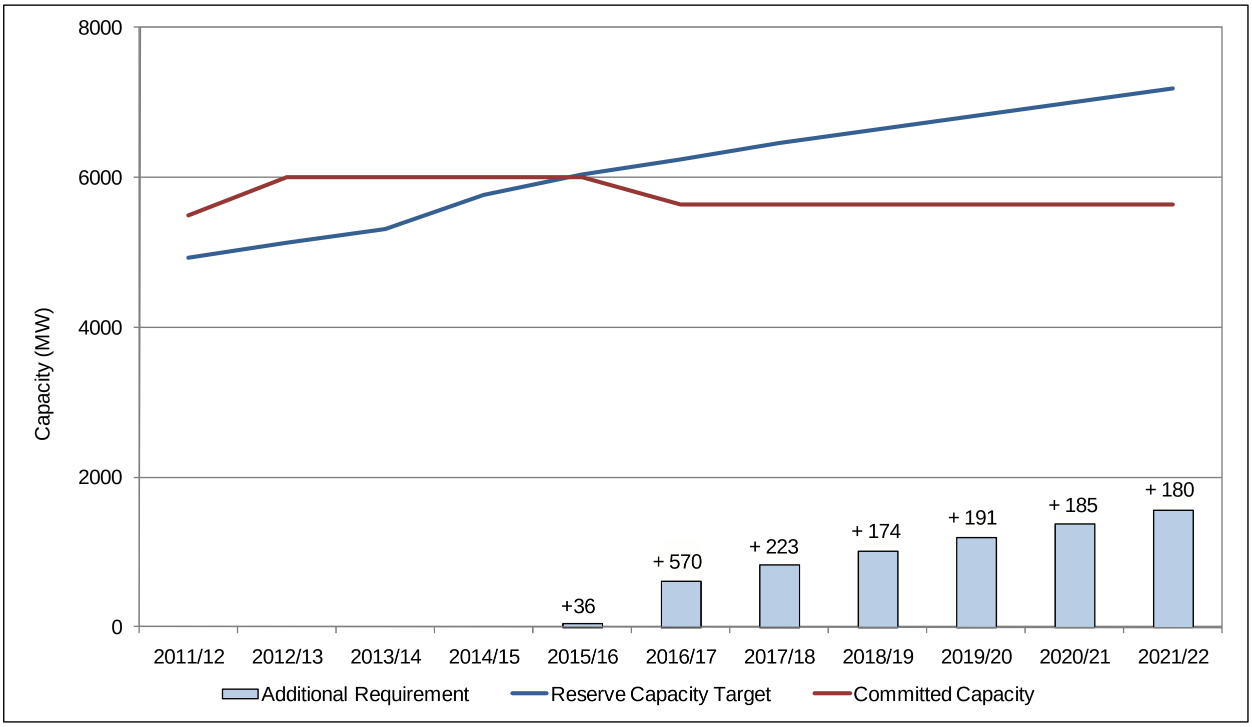
Figure A – Forecast Reserve Capacity Status for 2013/14



Supply-Demand Balance

Figure B shows the supply-demand balance over the period 2011/12 through to 2021/22.

Figure B – Supply-Demand Balance for the Period 2011/12 to 2021/22



Key points to note from Figure B are:

- Sufficient Capacity Credits have been procured to meet the Reserve Capacity Requirement during 2011/12 and 2012/13.
- Existing and committed capacity is expected to be sufficient to satisfy the Reserve Capacity Requirement for 2013/14 and 2014/15.
- By 2021/22 the total capacity requirement is forecast to be 7,193 MW. After allowing for the anticipated decommissioning of Verve Energy's Kwinana Stage 3, additional capacity of 1,559 MW is forecast to be required to service demand growth and to replace capacity that is likely to be retired.

Demand growth over the coming decade, with average State economic growth expected to exceed 3.5% per year, presents opportunities for new and existing investors to develop new generation and DSM capacity in Western Australia. More than 1,500 MW of new capacity is expected to be required over the coming decade to meet load growth.

Importance of New Transmission Works

The timing of new transmission works planned by Western Power is of particular importance for the 2013/14 Capacity Year. These works impact on the size and timing of new large block loads and the connection and certification of a number of proposed new generators.

The proposed Mid West Energy project southern section Neerabup to Eneabba 330kV double circuit transmission line has been specifically considered. This line could serve a number of planned mining loads and prospective power generation developments in the Mid West region. This project is still subject to various regulatory and funding approvals.

Three scenarios are relevant in assessing the impact of the new transmission works on demand forecasts and on the assignment of Certified Reserve Capacity to new generation facilities:

1. New transmission works are in service prior to 1 October 2013. This would enable the certification of new generation facilities that are reliant on the transmission works.
2. New transmission works come into service after 1 October 2013, but before or during the 2013/14 Hot Season (December – March). This would preclude the certification of new generation facilities that are reliant on the transmission works. However, peak demand and energy forecasts for 2013/14 would consider new loads that are expected to connect to the network upon completion of the transmission works.
3. New transmission works come into service after the 2013/14 Hot Season. New loads reliant on the transmission works would not be included in peak demand forecasts, but would be included in energy consumption forecasts.

The IMO has concluded that the new transmission works will not be completed by 1 October 2013, and that the new load that is dependent on the transmission works is unlikely to be in place during the 2013/14 Hot Season. The IMO has considered that this new load may be operating during the remainder of the 2013/14 Capacity Year.

The new load that is dependent on the transmission works has not been considered in the determination of the Reserve Capacity Requirement for 2013/14. Some additional Mid West load (95 MW) has been allowed for in the 2013/14 peak demand forecasts, based on information from Western Power on limited spare capacity in the existing network.

Further, as the new transmission works are unlikely to be in place by 1 October 2013, the IMO will not be able to certify new generation facilities that are reliant on the new transmission works for the 2013/14 Capacity Year.

The IMO has assumed that the new transmission works are in service by 1 October 2014, and the allowance for major loads has been increased by around 200 MW on the assumption that major Mid West mining and associated loads are operational by that time.

Section 4.3 of the SOO provides the information upon which the IMO's consideration is based.

The IMO notes that this is the second consecutive year in which it has delayed the introduction of these major Mid West loads in its forecasts. Further, the IMO notes that declining economic conditions or commodity prices could cause the relevant projects to be further delayed or cancelled.

Reform in the Wholesale Electricity Market

A number of reviews are currently underway that may result in changes to the WEM. These include:

- the Strategic Energy Initiative (SEI), being conducted by the Office of Energy;
- the Market Evolution Project (MEP), being conducted by the IMO with the assistance of the Rules Development and Implementation Working Group (RDIWG);
- the review of the Metering Code, being conducted by the Office of Energy;
- the review of the relevant sections of the *Electricity Corporations Act 2005* that restrict Verve Energy from retailing electricity and prohibit Synergy from generating electricity, being conducted by the ERA;
- a review of the RCM, being conducted by the IMO; and
- the review of the methodology for determining the Maximum Reserve Capacity Price (MRCP), being conducted by the IMO with the assistance of the Maximum Reserve Capacity Price Working Group (MRCPWG).

Many of these reviews, and other potential changes to the market, are described in greater detail in Chapter 7.

Next Steps

Parties offering a generation or a DSM facility as Reserve Capacity must register with the IMO as a Market Participant and must register their facilities for the purposes of Reserve Capacity. Market Participants must then apply for their facilities to be certified and apply to be assigned Capacity Credits.

Certification is required for all new and existing facilities. Applications for Certification of Reserve Capacity of generation and DSM capacity for the 2013/14 Reserve Capacity Year are now open and must be provided to the IMO by 5:00 PM WST on Wednesday, 20 July 2011.

Further information on the Reserve Capacity process is available on the IMO website at http://www.imowa.com.au. Parties planning to participate in these processes should familiarise themselves fully with the requirements of the relevant Market Rules and Market Procedures. Parties intending to participate in the WEM for the first time are strongly encouraged to contact the IMO at an early stage to discuss the market requirements for new entrants.

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Requirements of the Wholesale Electricity Market Rules

The following table is provided to assist readers wishing to find particular information in this report as required by the Market Rules. Market Rule 4.5.13 specifies the information that must be included in the Statement of Opportunities Report. The table below provides links to the appropriate section of the report for each of these items.

Market Rule	Report section where item is addressed
4.5.13. The Statement of Opportunities Report must include: (a) the input information assembled by the IMO in performing the Long Term PASA study including, for each Capacity Year of the Long Term PASA Study Horizon: i. the demand growth scenarios used;	Section 4 Appendix 3 Appendix 4 Appendix 5
ii. the generation capacities of each generation Registered Facility;	Appendix 9
iii. the generation capacities of each committed generation project;	Appendix 9
iv. the generation capacities of each probable generation project;	Section 5.6
v. the Demand Side Management capability and availability;	Appendix 9
vA. the amount of Reserve Capacity forecast to be required to serve the aggregate Intermittent Load;	Section 5.3
vi. the assumptions about transmission network capacity, losses and network and security constraints that impact on study results; and	Sections 4.3 and 7.2
vii. a summary of the methodology used in determining the values and assumptions specified in (i) to (vi), including methodological changes relative to previous Statement of Opportunities Reports;	Sections 3, 4 and 5
(b) the Reserve Capacity Target for each Capacity Year of the Long Term PASA Study Horizon;	Section 5.3
(c) the amount by which the installed generation capacity plus the Demand Side Management available exceeds or falls short of the Reserve Capacity Target for each Capacity Year and each demand growth scenario considered in the study;	Section 5.5 Appendix 6
(d) the extent to which localised supply restrictions will exist while satisfying the Reserve Capacity Target for each Capacity Year and each demand growth scenario considered in the study;	Sections 4.3 and 7.2
(e) a statement of potential generation, demand side and transmission options that would alleviate capacity shortfalls relative to the Reserve Capacity Target and to capacity requirements in sub-regions of the SWIS; and	Section 5.6
(f) the Availability Curve for the 2nd and 3rd Capacity Years of the Long Term PASA Study Horizon.	Section 5.4

1. Introduction

Growth in Western Australia has recovered significantly since the onset of the global economic downturn and the State economy is continuing to gain momentum, supporting growth in electricity demand.

Developers continue to invest in new capacity within the SWIS. In recent years, plans have been announced for further conventional generation in the South West, Mid West and Wheatbelt regions. At the same time, Commonwealth and State Government measures to encourage renewable generation are stimulating proposals for renewable projects with Expressions of Interest received this year for wind farm developments in the Wheatbelt and Great Southern regions. In addition, the Demand Side Management (DSM) sector is experiencing considerable growth, with DSM capacity set to grow from the current level of 153 MW to 454 MW by 2012/13.

This Statement of Opportunities Report (SOO) is published to primarily provide information on existing supply capacity and future electricity demand to parties considering participation in the Reserve Capacity Mechanism. As such, the SOO is a key element in the Reserve Capacity Mechanism, a series of processes through which the IMO identifies the requirement for future generation and Demand Side Management (DSM) capacity and facilitates the introduction of this capacity onto the South West interconnected system (SWIS).

The 2011 SOO contains a detailed profile of the SWIS, including:

- historical load data, including a current load duration curve and typical load profiles;
- a thorough analysis of the current generation mix;
- analysis of the current economic environment;
- updated expectations of the capacity available within the SWIS from that provided in the 2010 SOO, incorporating the 2011 Summary of Expressions of Interest (published in May 2011); and
- energy consumption and peak demand forecasts for the Long Term PASA Study Horizon, which extends to 2021/22.

Throughout the SOO, temperatures and electricity demand in the SOO are compared to probability of exceedance (PoE) levels. The probability of exceedance is the likelihood that the temperature or electricity demand will exceed a certain level. For example:

- a 10% PoE peak demand forecast would be expected to be exceeded only once in every ten years (10% of the time);
- a 50% PoE peak demand forecast would be expected to be exceeded once in every two years (50% of the time); and.
- a 90% PoE peak demand forecast would be expected to be exceeded nine times in every ten years (90% of the time).

2. Electricity Generation and Consumption in the SWIS

As the WEM uses sent-out capacity quantities (the net amount of electricity exported onto the transmission grid), the information provided in the SOO is presented in terms of sent-out capacity expressed in megawatts (MW), unless otherwise specified. Energy production is also presented in sent-out terms and is measured in gigawatt-hours (GWh).

2.1 2010/11 Summer Weather and Maximum Demands

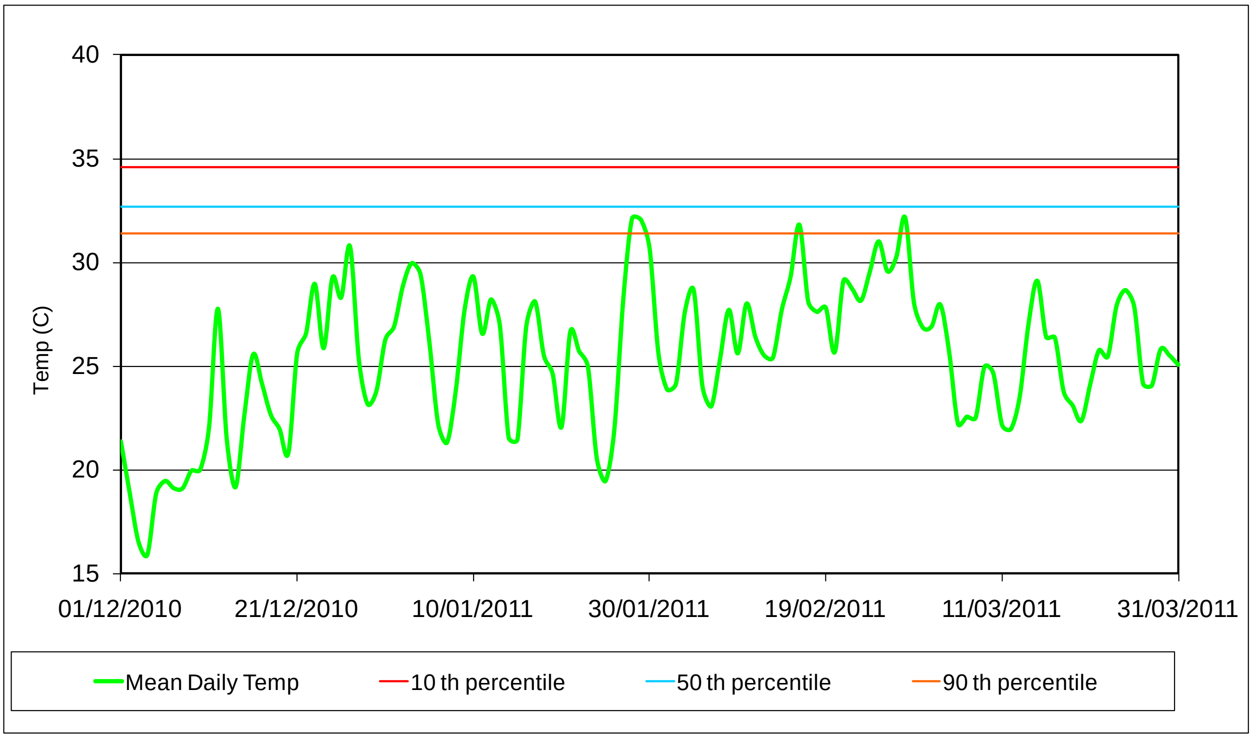
Electricity demand in the SWIS is strongly correlated with temperature. Summer maximum temperatures can range from the mid-twenties to the mid-forties, with consequent daily peak electricity demands from below 2,000 MW to above 3,700 MW.

The Hot Season for the SWIS is defined as the period from 1 December to 31 March, with the highest maximum demands expected between mid-January and mid-March. The daily peak demand is usually higher on business days than on weekends and public holidays.

Typically, the highest maximum demands are recorded when there is a sequence of hot days with high overnight temperatures. The IMO's forecasting is based on the mean of the minimum overnight temperature and the maximum temperature for each day. This "mean temperature" is used to predict the likelihood of a maximum demand event occurring.

Perth experienced temperatures well above average across the 2010/11 summer, with the average summer temperature being more than 1.5°C above the historic average. However, the daily maximum temperature only reached 40°C on two occasions, both of which fell on Saturdays prior to the end of January. This is reflected in Figure 1, which compares the Perth mean daily temperatures from December 2010 to March 2011 with the PoE levels given by the NIEIR.

Figure 1 – Perth Daily Average Temperatures December 2010 to March 2011



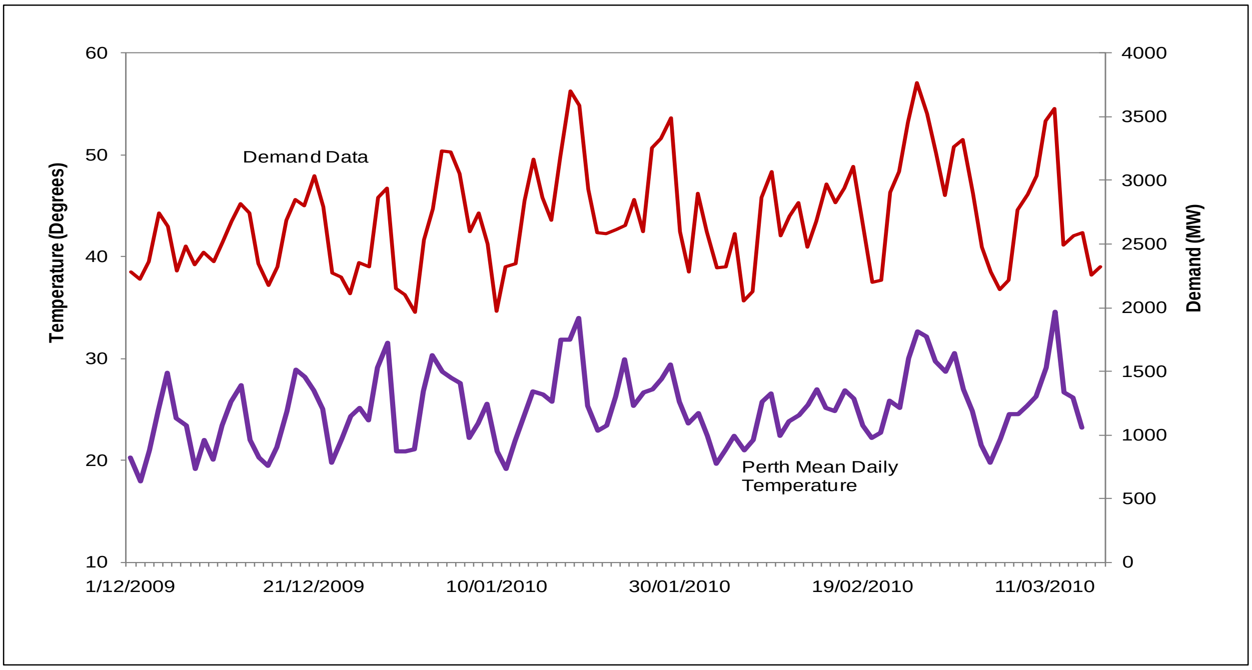
(Source: Bureau of Meteorology)

The 10%, 50% and 90% PoE temperature conditions have been determined by analysis of historic weather data. Mean daily temperatures (the arithmetic mean of the daily maximum and daily minimum temperature) for the Perth metropolitan region are the metrics used. Mean daily temperatures of 34.6°C, 32.7°C and 31.4°C correspond to the 10%, 50% and 90% PoE temperature conditions respectively.

From Figure 1 it can be seen that there were four days when the mean daily temperature exceeded the 90% PoE level, compared with seven in the previous Hot Season. It is worth noting that the mean daily temperature failed to exceed the 50% PoE level during the Hot Season. This is reflective of the fact that the Hot Season was characterised by sustained periods of above average temperatures whilst the daily maximum temperature only exceeded 40°C on two days.

The strong relationship between temperature and electricity demand during the Hot Season is shown below in Figure 2.

Figure 2 – Perth Mean Daily Temperature and Daily Peak Demand



The 2010/11 summer saw a disruption in gas supply from the Varanus Island processing facility due to Tropical Cyclone Carlos in late February. This led to the declaration of a High Risk Operating State by System Management and the dispatch of Demand Side Management (DSM) capacity on February 24, 25, 26 and 28. The previous dispatch of DSM facilities had been in January 2008. Assessment of the aggregated performance of DSM facilities shows that the required curtailment was delivered successfully in all intervals of dispatch.

The dispatch of DSM capacity is important when forecasting future capacity requirements. In determining the level of demand over the previous year, the IMO determines the quantity of capacity that was utilised in each Trading Interval. This requires that an estimate of the curtailment of DSM facilities be added to the quantity of sent out generation.

The IMO has estimated the curtailment of DSM facilities as the difference between the consumption of those facilities and their Relevant Demand, a baseline level of consumption that is used in assessing DSM capacity and performance. The IMO considers that this method, based on the Market Rules, is more robust than the complexity of trying to predict the likely consumption of loads if they had not been dispatched. However, the IMO notes that the use of the Relevant Demand may overstate the curtailment by up to 20 MW. This does not materially affect the forecasts of future demand, as the forecasting models are based on a much greater volume of historical load data.

The maximum sent-out generation for 2010/11 was 3,741 MW on 16 February 2011. However, when the curtailment of DSM facilities is added to the generation quantity, the peak demand is estimated to be 3,831 MW on 25 February 2011 (Trading Interval from 16:30 to 17:00). This is 1.7% higher than the 2009/10 peak demand of 3,766 MW.

The demand during the peak interval comprised 3,702 MW of generation and an estimated 129 MW of DSM curtailment. The mean daily temperature on this day was 31°C, making it the fifth hottest day in the summer, corresponding to a PoE level of approximately 97%. This was preceded by a mean daily temperature of 29.5°C on the previous day.

The peak demand of 3,831 MW compares well with the IMO's peak demand forecasts from the 2009 and 2010 SOO's. Table 1 shows the difference between the actual peak demand in 2011 and forecasts provided in the SOOs since 2005. The 90% PoE forecasts are chosen for comparison as these most closely relate to, though would be expected to slightly overestimate, the peak demand on a cooler 97% PoE day.

Table 1 – Temperature-Corrected Forecast Accuracy

Maximum demand = 3831 MW		Accuracy (MW)	Accuracy (%)
2005 Temperature-Corrected Forecast	3510	-321	-8.4%
2006 Temperature-Corrected Forecast	3689	-142	-3.7%
2007 Temperature-Corrected Forecast	3803	-28	-0.7%
2008 Temperature-Corrected Forecast	4167	336	8.8%
2009 Temperature-Corrected Forecast	3832	1	0.1%
2010 Temperature-Corrected Forecast	3774	-57	-1.5%

Table 1 also shows that the 2010/11 peak demand is significantly higher than the forecast provided in 2005 and 2006 and slightly higher than that provided in 2007. The 2008 forecasts, which show the most substantial discrepancy, included allowances for approximately 260 MW for new large block loads in the Mid-West and Great Southern regions, particularly iron ore mines that continue to be delayed following the onset of the Global Financial Crisis (GFC). Forecasts for 2009 and 2010 reflect lower growth expectations due to the impact of the GFC.

The considerable year-on-year variation is a reflection of increasing visibility of new large loads, and of the significant difficulties in forecasting in recent years. In general, improved accuracy is expected as the date of forecast approaches the Capacity Year being forecast.

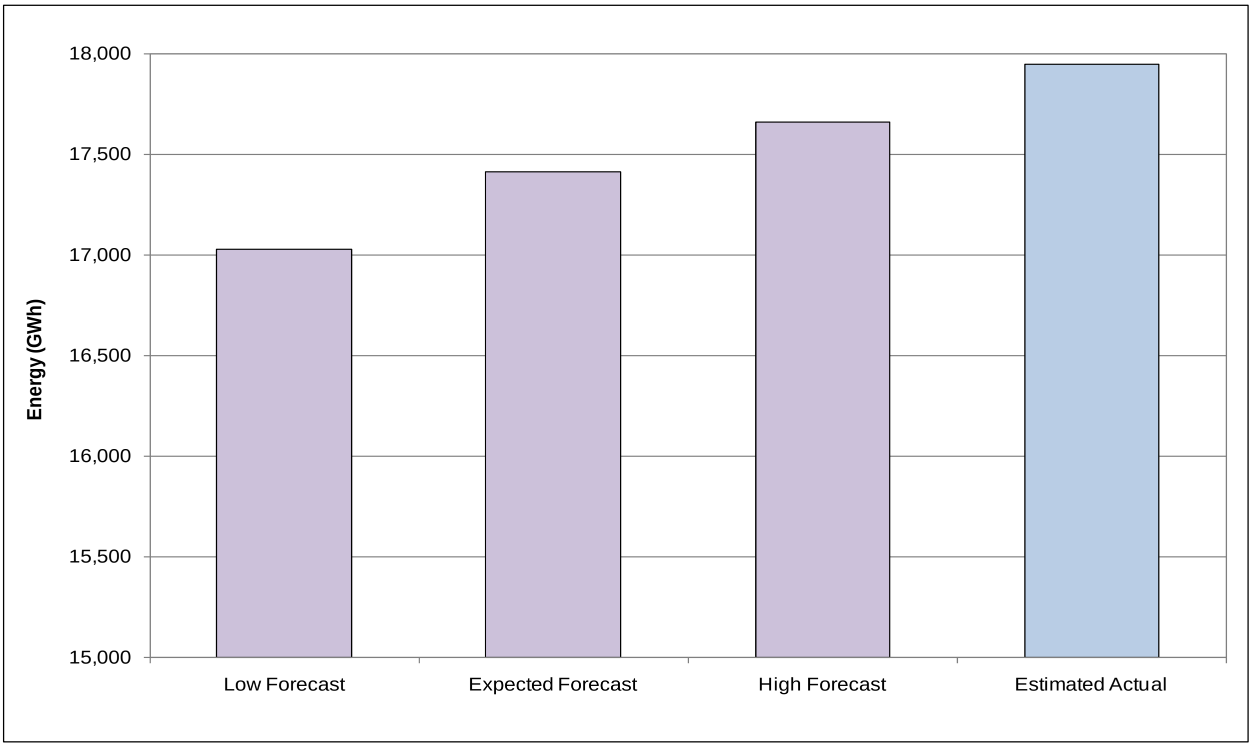
2.2 Actual Sent-Out Energy

As noted previously, annual energy consumption is less sensitive to peak temperatures than peak demand. However, sustained periods of high temperature can have a significant effect on energy consumption.

The high average summer temperature, more than 1.5°C above the historical average, has contributed to the energy consumption for 2010/11 exceeding the forecasts published in the 2010 SOO.

Figure 3 compares forecast energy from the 2010 SOO for Expected, Low and High growth cases with the estimated energy consumption for the 2010/11 financial year of 17,945 GWh. This estimate comprises nine months of actual data plus three months of estimated energy consumption to the end of June 2011.

Figure 3 – Comparison of Actual and Forecast Sent-Out Energy for 2010/11



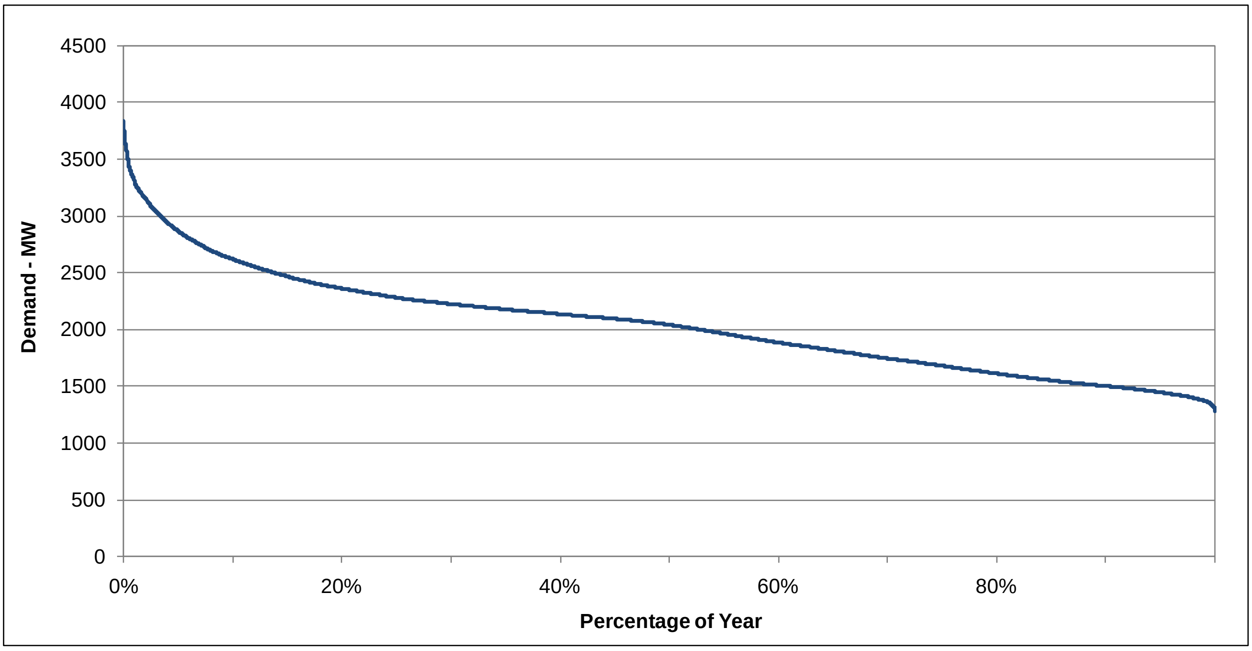
2.3 SWIS Load Duration Curve

In an electricity system, variation in demand can be examined in a load duration curve. This shows the demand in the system against the percentage of time for which it is reached or exceeded.

The load duration curve provides an insight into the likely optimum mix of generation types. Base load and mid-merit generation facilities are best suited to meet demand that is present for much of the year. Conversely, demand that only occurs for a small part of the year is best supplied by peaking generators or DSM.

The load duration curve for the SWIS is characterised by sharp summer peaks, a feature that is evident in Figure 4, which shows the load duration curve for the period from April 2010 through to March 2011. During this period, the load exceeded 90% of the annual maximum (i.e. 3,447 MW) for only 79 half-hour trading intervals, representing less than 0.5% of the year. Similarly, the load exceeded 80% of the annual maximum (i.e. 3,064 MW) for only 2.7% of the year. This indicates that a significant level of generation and network capacity is only utilised for a very small portion of the year.

Figure 4 – Load Duration Curve April 2010 to March 2011



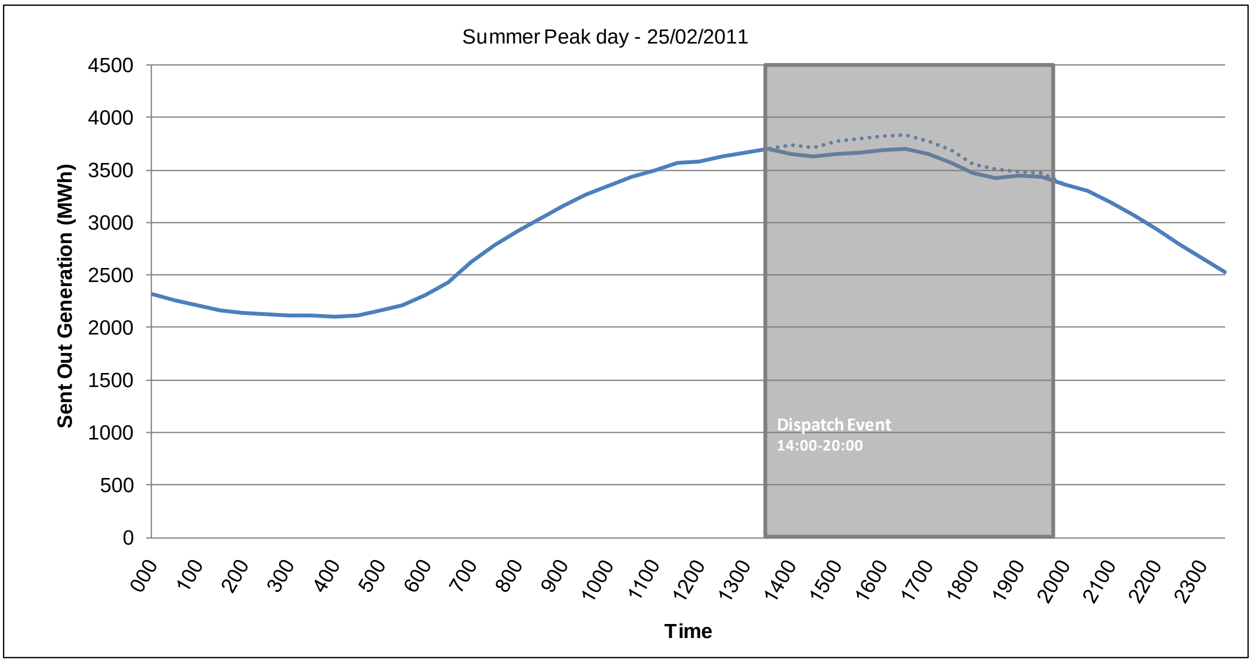
Other observations from this figure are that:

- The mean load over the year was 2,040 MW, which is 53% of the maximum demand compared with 52% last year. In recent years, the average load factor for the SWIS has been declining, but the increase in this year is reflective of the sustained high temperatures through the summer with a relatively cool peak demand day.
- The minimum load was 1,283 MW at 2:30 AM on 4 May 2010 compared with 1,260 MW last year.

2.4 Typical SWIS Daily Load Shape

Electricity demand varies substantially through each day with overnight loads being markedly lower than daytime demand. Figure 5 illustrates this, showing the level of demand (generation plus DSM curtailment) in each trading interval on 25 February 2011, the day of highest maximum demand. While the peak demand for the day exceeded 3,800 MW, the overnight demand was as low as 2,100 MW. Appendix 7 includes further daily load curves covering the winter day with the highest maximum demand and typical autumn and spring days.

Figure 5 – Daily Load Curve 2011 Peak Demand Day (25 February 2011)



In the period from April 2010 to March 2011, the largest intra-day differential between maximum and minimum load was 1,861 MW, which occurred on 16 February 2011. The minimum load on this day was 1,879 MW and the maximum load was 3,740 MW.

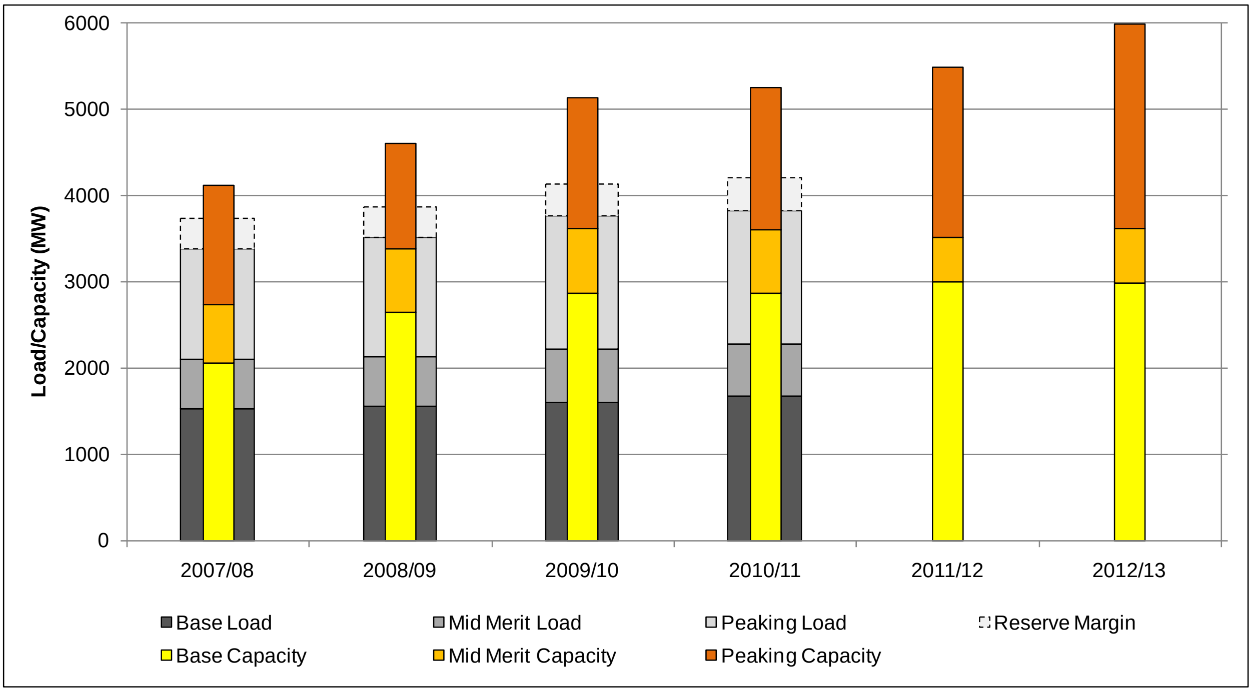
2.5 Information on Market Generators

2.5.1 Load Characteristics and Generation Mix in the SWIS

As discussed in section 2.3, the optimum mix of capacity will be driven to some extent by variation of demand throughout the year, as displayed in the load duration curve.

Figure 6 below analyses this by categorising both load and capacity into base, mid-merit and peaking classes. Base load has been defined as the level of demand that is exceeded for 75% of the year, mid-merit load as the additional demand that is exceeded for 25% of the year and peaking load is the level of demand that is only present for less than 25% of the time. The available capacity has been similarly classified according to the amount of time that each facility is operated.

Figure 6 – SWIS Load Characteristics and Capacity Mix



As can be seen in Figure 6, substantial investment was made in new base load generation capacity for the SWIS in the early years of the WEM. This has led to a surplus of this capacity in the near term and has required some cycling of plant during periods of lower demand (e.g. overnight). However, a correction is evident with the level of base load capacity expected to remain steady at least until the 2012/13 Capacity Year.

Conversely, peaking capacity is less than the peaking load since 2008/09, though this does not pose a problem in the event of surplus capacity in the other classes. The introduction of substantial volumes of DSM in recent Reserve Capacity Cycles will result in a doubling of peaking capacity from 2008/09 to 2012/13.

2.5.2 Capacity Credits by Fuel Type

The optimum mix of capacity is also likely to include significant diversity of fuel types.

Highly utilised generators (base load and mid-merit) will usually use low-cost fuels such as coal or natural gas. However, low-cost fuels can incur large fixed costs for transport, storage and processing. These high costs can be warranted if utilisation is high.

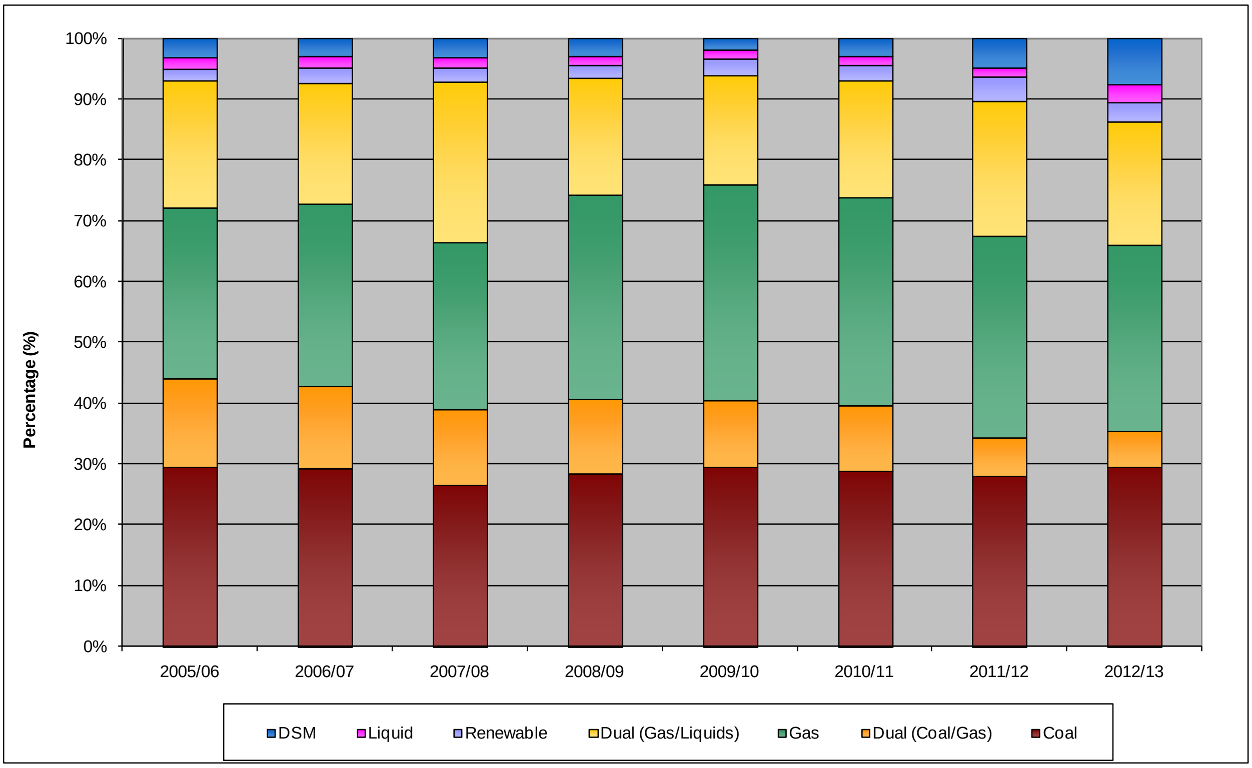
Conversely, plants operating only rarely (peaking) may have lower total costs if other fuels are used – perhaps with higher unit costs, but lower fixed costs. For example, high-cost distillate fuel can be the best choice for plants which will run only at peak demand times.

Diversity of fuel types can mitigate against failures or restrictions in the supply of a particular fuel type. For instance, access to coal-fired, distillate-fired and dual-fuelled generation capacity was very important in minimising the impacts of the Varanus Island gas supply disruption in

2008. The impact of the further gas supply disruption from Varanus Island due to Tropical Cyclone Carlos in February 2011 was somewhat mitigated by fuel diversity and the contribution of DSM.

While there have been some changes to the mix of fuel types, the significant diversity of capacity has continued since the introduction of the Reserve Capacity Mechanism. Figure 7 illustrates this, showing the composition of the generation capacity based on fuel type, for each year since the 2005/06 Capacity Year. Increases in generation have been experienced across each of the fuel types within the SWIS excluding dual coal/gas-fired capacity, which has reduced with the retirement of the Kwinana Stage B plant.

Figure 7 – Percentage of Capacity Credits by Fuel Type



A key observation from this figure is that the vast majority of capacity continues to be coal- or gas-fired. More recently, the percentage of Capacity Credits assigned to liquid-fuelled plant and DSM has increased significantly in the last two Reserve Capacity Cycles.

The percentage of dual-fuel capacity has decreased. As discussed in Section 7.4, the IMO recognises the need for incentives for investment in dual fuelled generation plant.

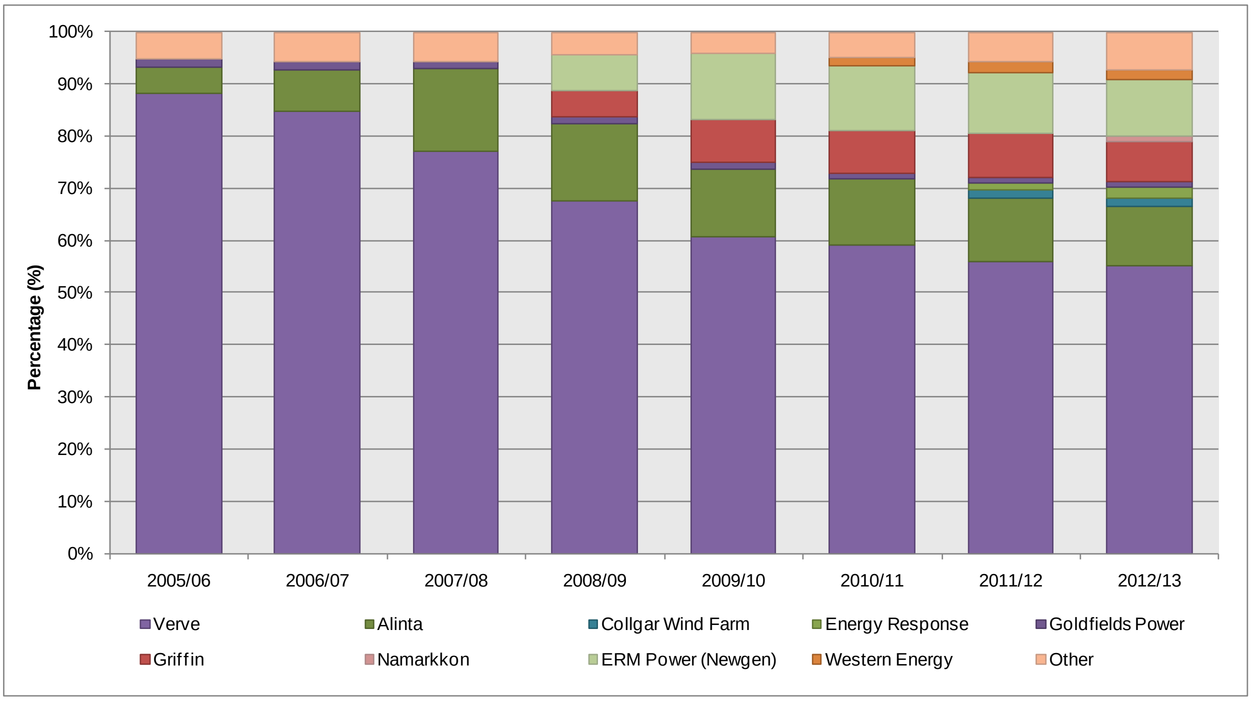
2.5.3 *Capacity Credits by Market Participant*

Various measures were implemented around the time of commencement of the WEM that have increased the diversity of Market Participants providing capacity to the SWIS and decreased the proportion of capacity provided by Verve Energy. These measures have included:

- the Displacement Mechanism within the original Vesting Contract between Synergy and Verve Energy, which required Synergy to procure specified volumes of capacity through a competitive tender process (no longer in effect);
- the Ministerial Direction on Verve Energy that capped Verve Energy's generation capacity at 3,000 MW[1]; and
- the Reserve Capacity Mechanism.

Figure 8 shows the Capacity Credits assigned to Market Participants as a percentage of the total number assigned in the SWIS for each year since the 2005/06 Capacity Year. The proportion of Capacity Credits held by Verve Energy has reduced from 89% at energy market commencement and is projected to be 55% in 2012/13. The graph also shows growth in the number of Market Participants providing capacity to the SWIS.

Figure 8 – Capacity Credits by Market Participant (minimum 1% market share)



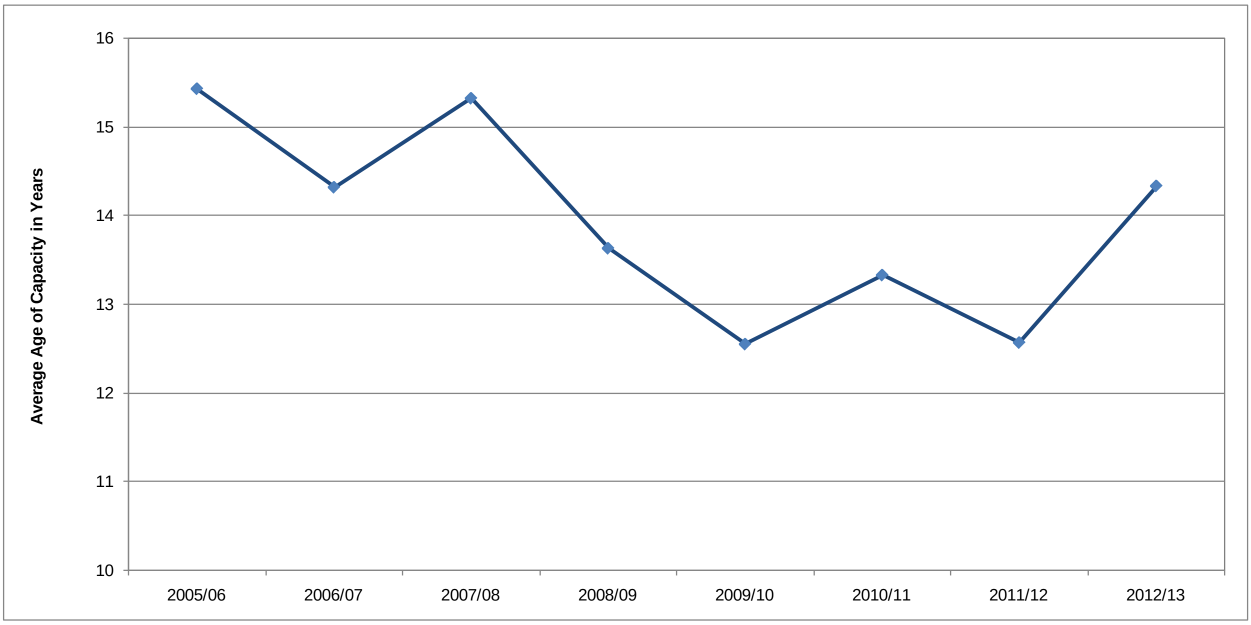
[1] The capacity cap refers to nameplate capacity within the SWIS and excludes renewable generation facilities. The Direction exempted certain pre-existing Power Purchase Agreements in place between Verve Energy and facilities owned by third parties. Verve Energy was granted an exemption to the capacity cap for the refurbishment of the Muja AB facilities by Vinalco (a joint venture between Verve and Inalco Energy). Available at http://www.energy.wa.gov.au/cproot/762/4809/EGC%20Ministerial%20direction%20(SSO%20Final)%2020%2003%2006.pdf.

2.5.4 Age and Availability of Generation Plant

The age of generation plant can influence its efficiency, reliability, flexibility and production cost.

As can be seen in Figure 9, the average age of generating capacity on the SWIS has generally fallen over the years since market start. This reflects the rapid introduction of new capacity over recent years and the retirement of older plant. 2012/13 is the exception to this positive trend. The 2012/13 increase in average age is materially impacted by the re-commissioning of Muja AB, which commenced generation in stages from 1966.

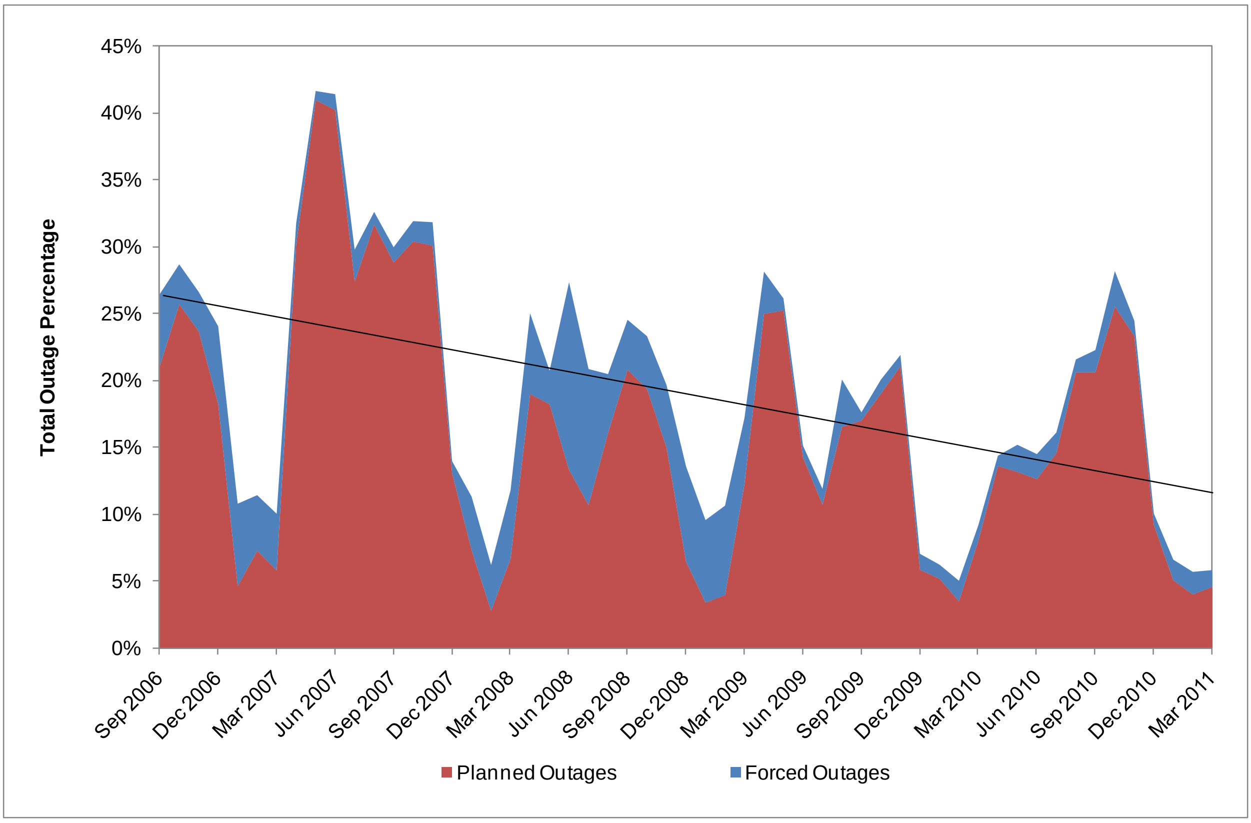
Figure 9 – Average Age of Generation Capacity



Given that the economic life of a power station is typically more than 30 years, the average age of SWIS generation reflects the high level of investment in new capacity in recent years. There will continue to be fluctuations year on year depending on the addition of any new capacity, upgrades to existing facilities and retirement of any plant.

Figure 10 shows the planned and forced outage rates displayed as a percentage of the allocated Capacity Credits in the market. The linear trend line of reducing facility outage rates is consistent with the reducing plant age. The seasonality of the outage rates is obvious, indicating the scheduling of Planned Outages outside the Hot Season.

Figure 10 – Monthly Average Outage Percentage

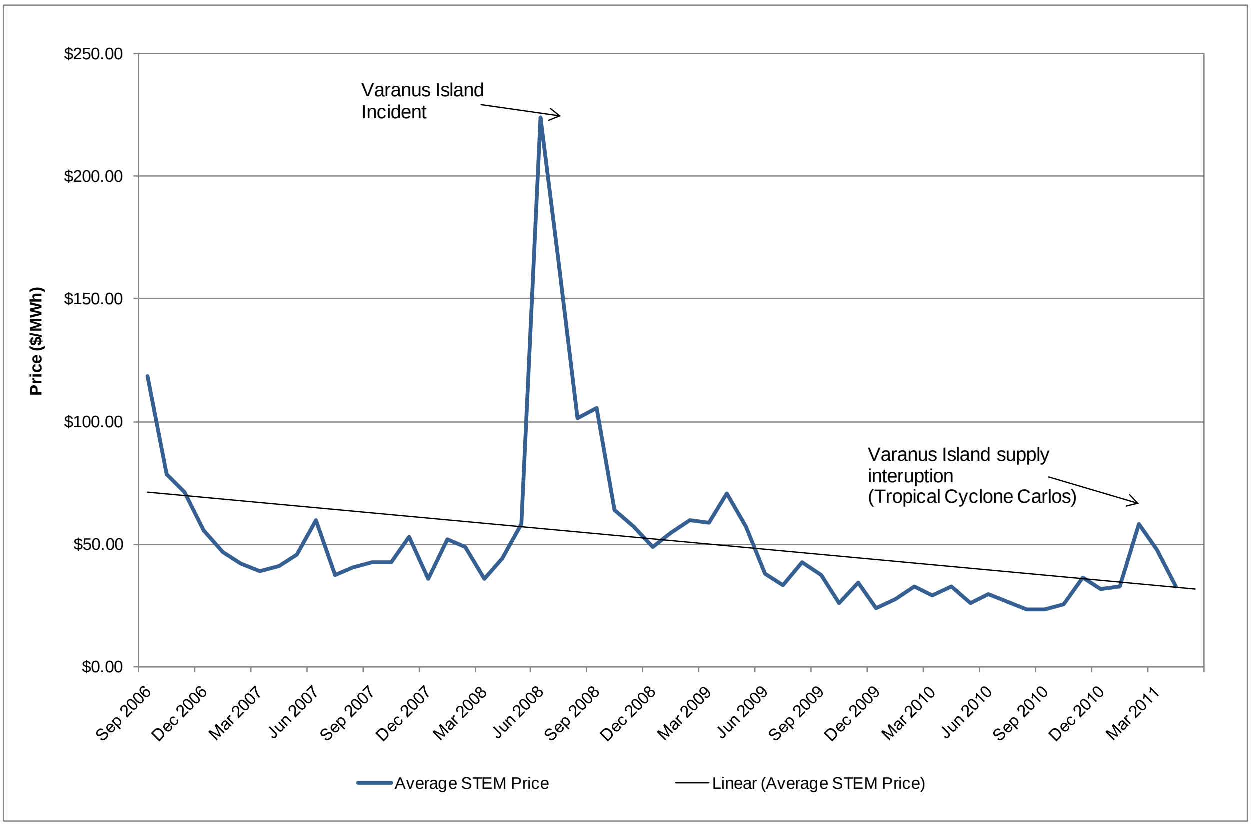


2.6 Energy Pricing in the Wholesale Electricity Market

The energy trading component of the Wholesale Electricity Market (WEM) has been in operation since Energy Market Commencement (EMC) on 21 September 2006. In that time, the energy price has proven to be responsive to changes in the supply-demand balance in the SWIS. As the energy trading mechanisms in the WEM have matured, trading quantities have increased and downward pressure on prices has been observed, indicating increasing competition in the WEM.

The monthly average price has shown a downward and generally linear trend since EMC as shown in Figure 11. In this plot, the blue line indicates the monthly average price in the Short-Term Energy Market (STEM) and the black line indicates the linear trend for the whole dataset.

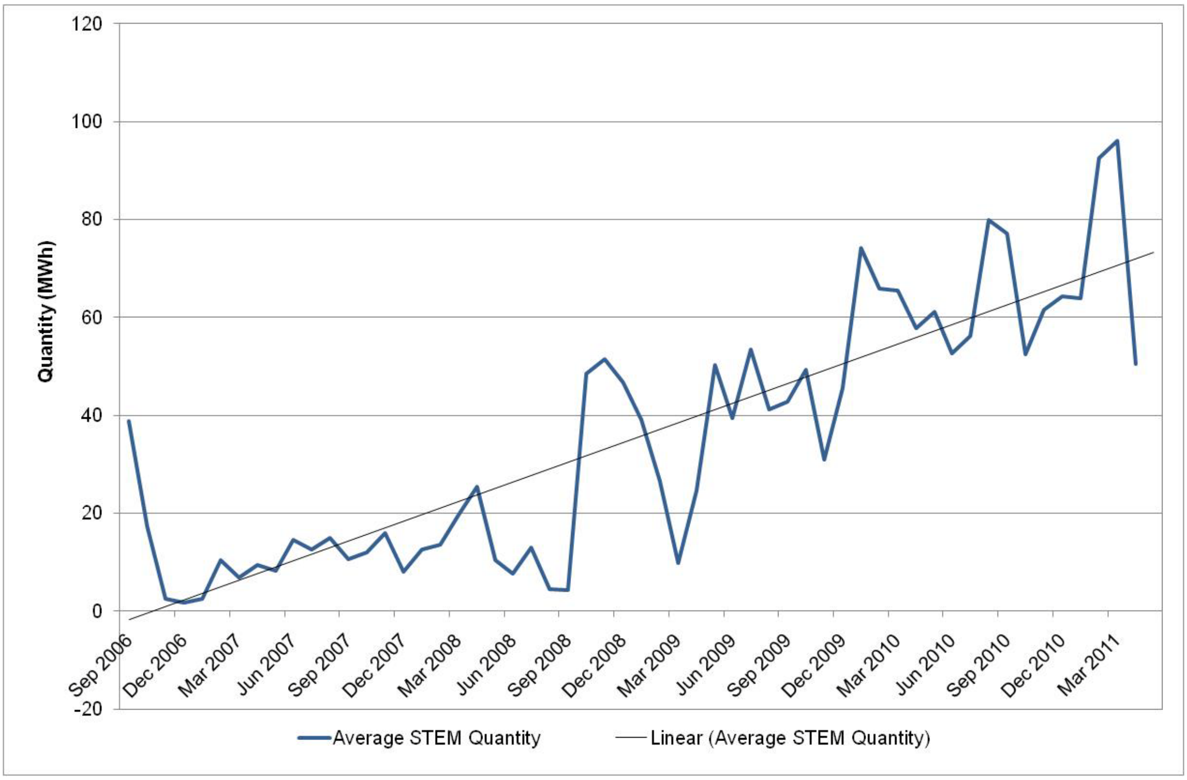
Figure 11 – Monthly Average STEM Price



The monthly price can be seen to be high initially at EMC, which suggests an adjustment period reflective of inexperience with the trading mechanisms. The Varanus Island gas explosion in 2008 caused severe price spikes in the period between June and August, indicative of the supply restrictions on natural gas during that time. The price spike during February and March 2011 was caused by the shorter interruption in gas supply from Varanus Island triggered by Tropical Cyclone Carlos.

Increased competition is also evident in the growing quantity traded in the STEM. Figure 12 shows the increasing trend of the quantity of energy traded per interval. The entry of new independent power producers (IPPs) into the WEM has been a key driver towards increased competition, and this trend is likely to continue with new IPPs due to enter the market in the coming years. Another factor has been a steady rise in the usage of the STEM as a tool for Market Participants to adjust risk around their bilateral contract positions.

Figure 12 – Average STEM Quantity Traded (per interval)



Spikes in the quantity traded in the STEM are evident around the commencement of the 2008/09, 2009/10 and 2010/11 Capacity Years, with the quantity reducing shortly after. These are coincident with the entry of large new facilities into the WEM, and suggest that the owners of these facilities have traded energy in the STEM prior to the commencement of their bilateral contracts.

3. Economic Environment

3.1 Background

Economic forecasts are an important input in electricity forecasting. The level of economic activity has both a general and specific impact on the maximum demand for, and consumption of, electricity. Economic conditions will affect the level of discretionary spending by consumers, including items such as air-conditioning systems and other energy-intensive consumables. Construction activity is also strongly correlated with the strength of the economy, and leads directly to the purchase and usage of electrical appliances and demand for basic materials.

Resource extraction, processing and export are significant to the Western Australian economy and to electricity demand growth. Some of these activities have a direct impact on demand in the SWIS. Of particular relevance at present are proposed iron ore developments that have substantial power needs for mineral processing.

Major developments in regional areas outside of the SWIS can also have a significant impact on SWIS electricity demand:

- Much of the design, procurement and management support are provided by personnel based within the Perth metropolitan area.
- Much of the fly-in/fly-out workforce resides in the SWIS.
- Substantial quantities of basic materials, equipment and services are sourced from within the SWIS.
- This economic activity has boosted population growth in Western Australia, particularly through interstate and overseas migration during the last 5 years.

The forecasts included in this report show a slight decrease in the compound economic growth rate in Western Australia over the next few years, compared with those in the 2010 SOO. This decrease flows through to a decrease in the forecast growth rate for base electricity demand and consumption through to 2021, prior to the consideration of new block loads.

This chapter includes discussion on changes in economic outlook which have occurred since the 2010 SOO. A comparison is also provided between NIEIR's forecasts and a number of other publicly available forecasts.

3.2 Economic Outlook

Figure 13 and Figure 14 show the forecasts of economic growth in Australia and Western Australia, measured by Gross Domestic Product (GDP) and Gross State Product (GSP) respectively, through to 2021/22 for the Expected, High and Low growth cases.

Figure 13 – Forecast Australian Economic Growth

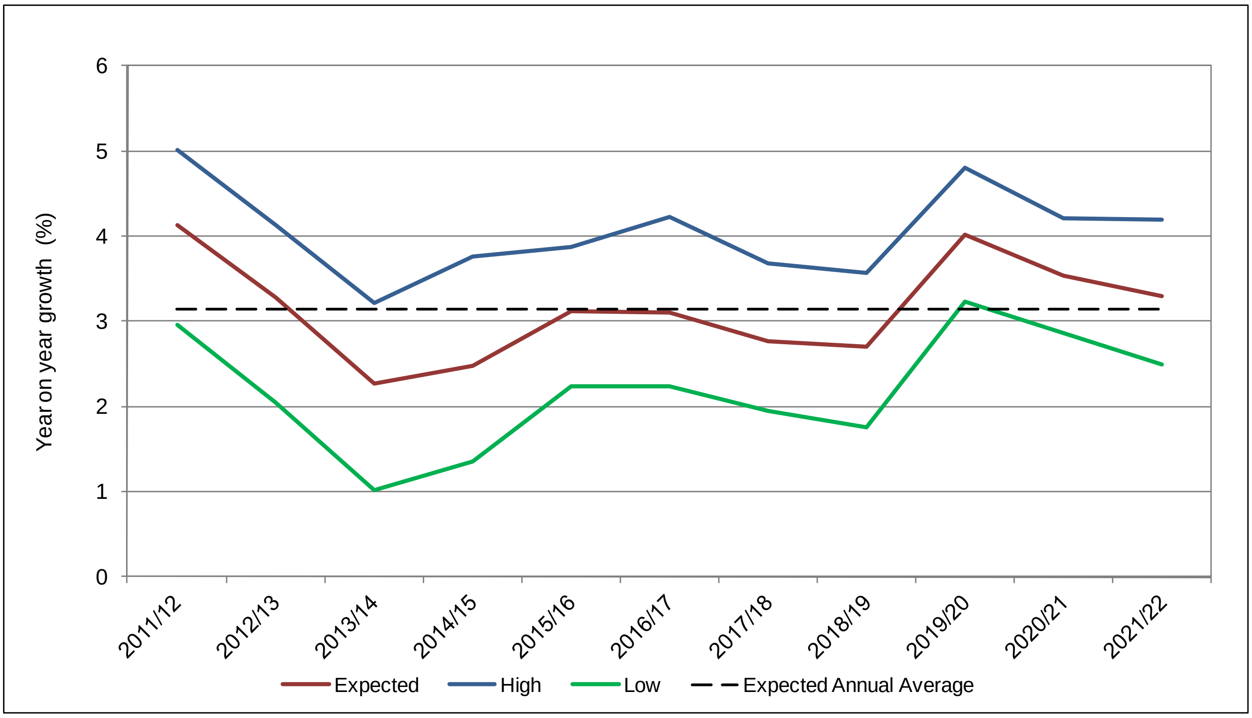
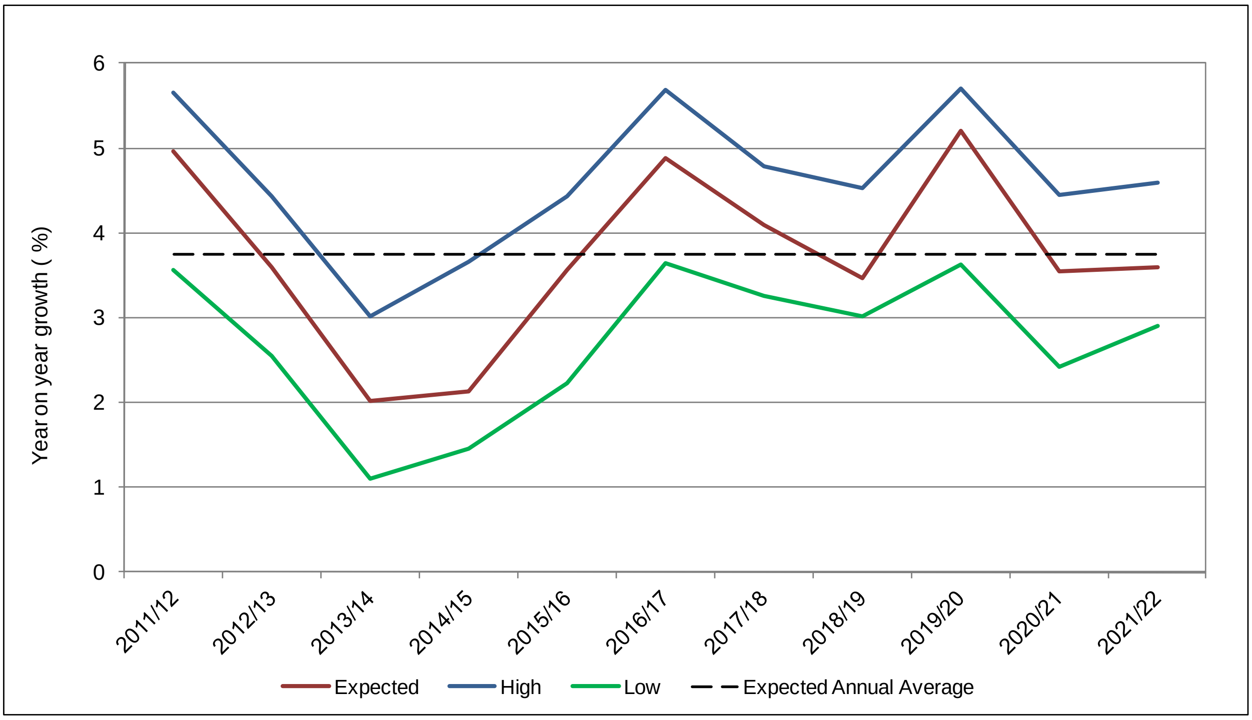


Figure 14 – Forecast Western Australian Economic Growth



NIEIR forecasts that Australia's annual average economic growth over the period to 2021/22 will be approximately 3.2% while the Western Australian economy is expected to grow faster at 3.8% per year over the same period. By comparison, the 2010 SOO reported growth rates through to 2020/21 of 3.0% and 4.2% for GDP and GSP respectively.

A year-on-year comparison of 2010 and 2011 GDP and GSP forecasts from NIEIR for the short term is provided later in this chapter (Figure 17 and Figure 18).

During the last decade, the resources boom has resulted in rapid growth in Western Australia with flow-on effects in the general economy including the region covered by the SWIS. However, the global economic slowdown that commenced in 2008 has led to the postponement and/or cancellation of a number of major resource developments.

In 2010/11 Western Australia's economic growth has remained strong with GSP growth estimated to reach approximately 4.0%, due in part to major resources projects which have contributed to rapid growth in private business investment. This growth is forecasted to increase further into 2011/12. However, the economy is predicted to experience a decline in growth from 2012/13, driven by the high currency exchange rate, which leads in turn to a loss of exports and lower growth in consumer demand and business investment.

NIEIR forecasts that inflationary pressures and higher interest rates will then combine to further slow economic growth, leading to a reduction in GSP growth in 2013/14 to 2.0% per annum.

Figure 15 compares NIEIR's Australian economic growth forecasts with those of three other organisations:

- the Commonwealth Government Budget Papers (published in May 2011);
- a major independent forecaster (published in April 2011); and
- the Commonwealth Bank Economic Forecast (published May 2011).

This comparison of Australian growth rate forecasts is presented on a compounded basis to smooth out the variations that occur from year to year, and shows excellent agreement between the forecasts. The "Independent Forecaster" included in the graph has requested that it not be named. Note that the Commonwealth Bank forecast extends only to 2012/13, so it is excluded from the 2013/14 comparison.

Figure 16 shows that the NIEIR forecasts of Western Australian GSP growth year-on-year for 2010/11 through to 2012/13 are in reasonable agreement with those published by the Western Australian Department of Treasury and Finance (DTF) in the May 2011 budget papers.

However, the GSP growth forecasts diverge for 2013/14 and 2014/15. DTF forecasts sustained growth at 4% for these years with exports becoming the main driver of growth. NIEIR predicts that higher inflation and interest rates will dampen household expenditure and dwelling construction activity. These factors, combined with a predicted drop in private business investment, slow growth to around 2%.

Figure 15 – Compound Australian Economic Growth

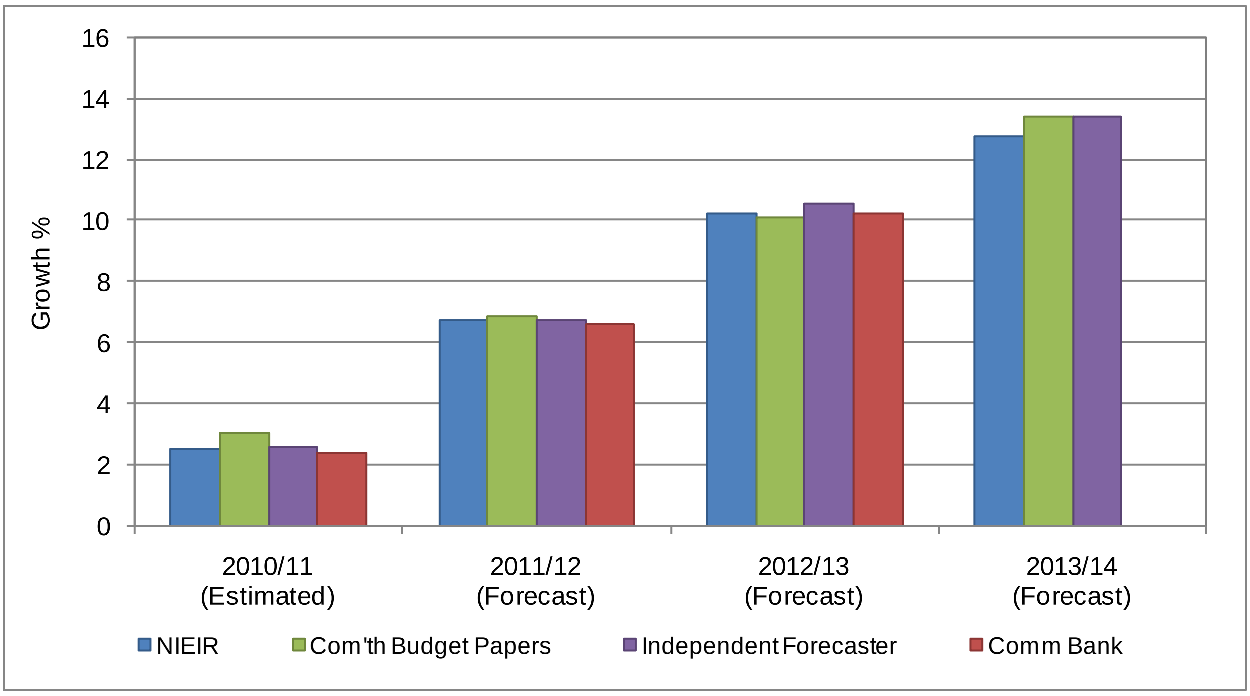
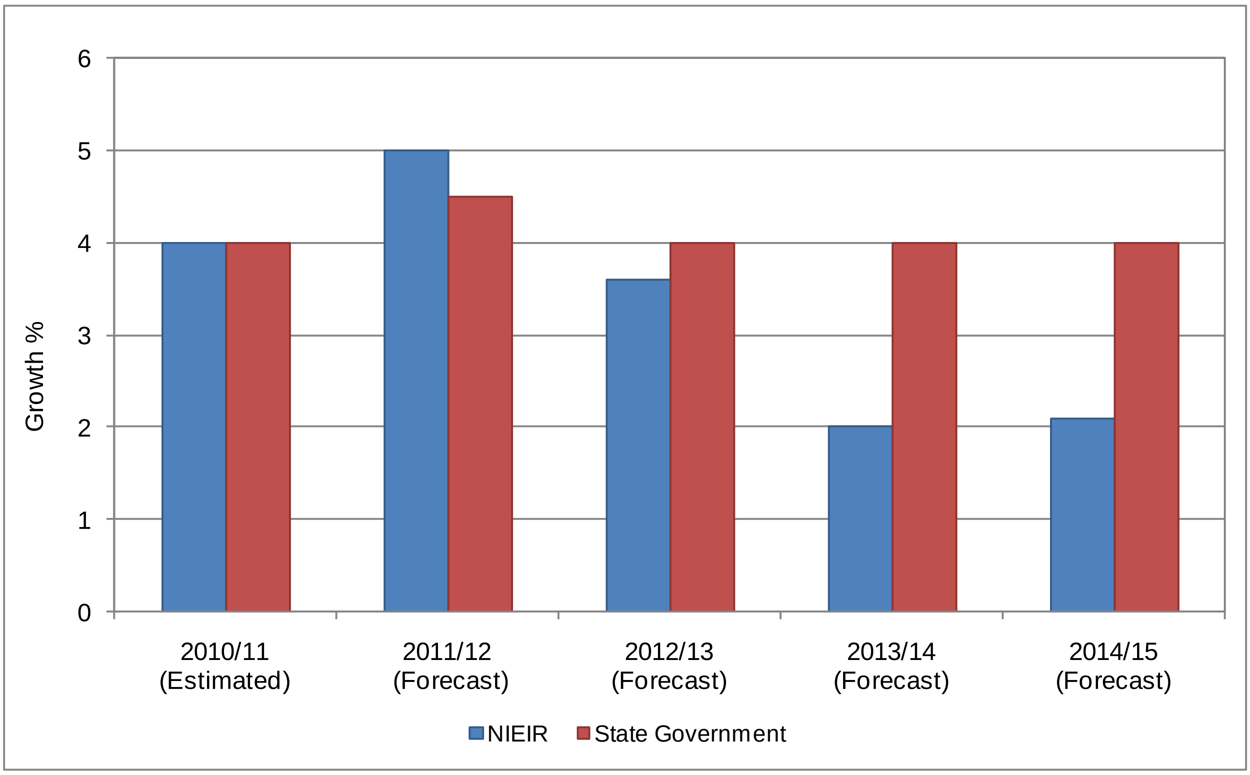


Figure 16 – Comparison of WA Economic Growth Forecasts



3.3 Differences Between the 2010 and 2011 Economic Forecasts

Figure 17 and Figure 18 compare NIEIR's 2010 and 2011 short-term forecasts for GDP and GSP respectively. At the time of publication of the 2011 SOO, NIEIR was forecasting lower economic growth in Australia in 2010/11. This revision downwards is largely the outcome of the floods, loss of exports and lower growth in consumer demand and business investment. Figure 17 shows a larger upswing in economic growth is predicted to occur in 2011/12 in comparison to last year's forecasts. From 2011/12 onwards NIEIR has revised their economic growth upwards compared with the forecasts from last year.

Growth in the Western Australian economy in 2009/10 was stronger than expected. However, the forecasts from 2010/11 onwards are overall lower than what was expected in last year's forecasts, showing a smoother growth profile in the medium term.

The IMO notes that the year-on-year variation, shown in the stronger 2009/10 growth, can result from the revision of historical economic data by the Australian Bureau of Statistics (ABS). For example, the 2009 State Accounts report indicated that Western Australia's GSP growth for the 2008/09 financial year was 0.7%, whereas the 2010 State Accounts report quoted growth of 4.1% for the same financial year.

The softer Western Australian growth rates from 2010/11, compared to last year's forecast, result from the following predictions:

- falls in commodity prices around the middle of the decade;
- later commencement of LNG projects, due in part to LNG projects in Queensland; and
- lower household consumption expenditure due to the combined impact of high dwelling prices, leading to high household debt levels, and rising interest rates.

Figure 17 – Comparison of 2010 and 2011 Australian Economic Growth Forecasts

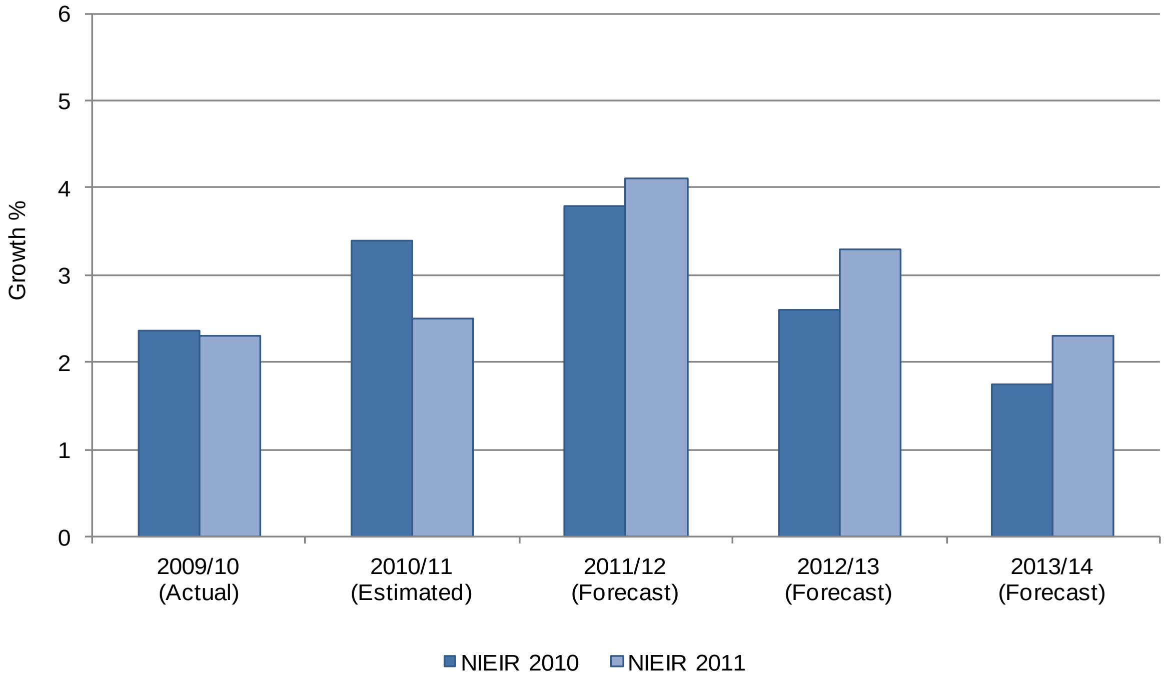
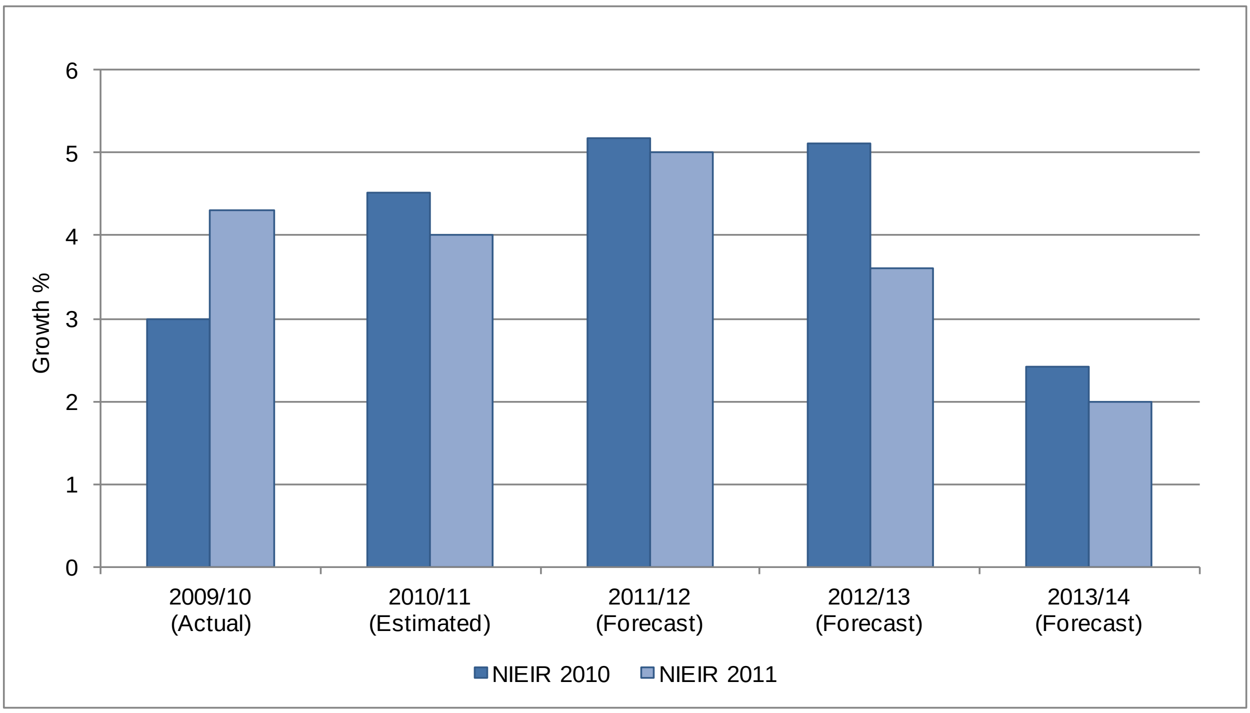


Figure 18 – Comparison of 2010 and 2011 WA Economic Growth Forecasts



4. Peak and Demand and Energy Forecasts 2010/11 to 2020/21

4.1 Background

The IMO publishes two sets of forecasts each year within the SOO. These forecasts cover:

- the maximum demand, which is the measure of the highest level of power consumption at any point in time over the year (measured in MW); and
- electricity consumption, which is the amount of energy sent-out and consumed within the SWIS over the full year (measured in GWh).

As noted in Chapter 3, electricity consumption is driven, to a large extent, by underlying economic-based drivers. Maximum demand is less dependent on economic growth but is highly correlated with ambient temperatures.

The IMO provides three groups of peak demand forecasts based on specific temperature conditions for the peak day in the summer:

- the 10th percentile temperature condition which is expected to be exceeded only once in every ten years (10% PoE);
- the 50th percentile temperature condition which is expected to be exceeded once in every two years (50% PoE); and
- the 90th percentile temperature condition which is expected to be exceeded nine times in every ten years (90% PoE).

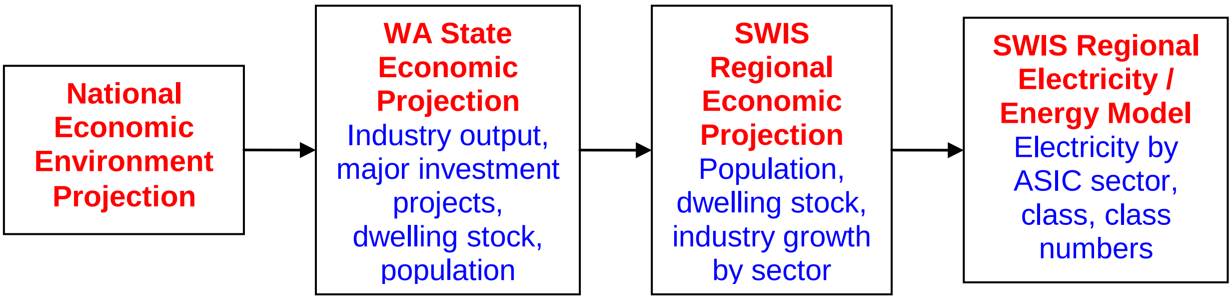
As noted in Section 2.1, mean daily temperatures of 34.6°C, 32.7°C and 31.4°C correspond to the 10%, 50% and 90% PoE temperature conditions respectively.

The maximum demand and electricity consumption forecasts used to determine the Reserve Capacity Target are based on Expected economic growth conditions. The forecast outcomes associated with High or Low economic growth conditions are provided as a guide to the variability in outcomes that could be expected.

4.2 NIEIR's Forecasting Methodology

NIEIR prepares forecasts of economic activity, electricity consumption and maximum demand for many of the electricity jurisdictions within Australia. For the SWIS, NIEIR has prepared forecasts for the past eight years, initially for Western Power Corporation and subsequently for the IMO's SOO. The energy forecasting process used by NIEIR is comprised of a number of different econometric forecasting modules. Figure 19 shows the relationships between the major components of NIEIR's integrated energy modelling systems.

Figure 19 – NIEIR Energy and Electricity Forecasting Systems



The core tool used by NIEIR is its national econometric model of the Australian economy. This provides projections of national economic growth using inputs from various statistical sources including the Australian Bureau of Statistics and the Australian Taxation Office.

The national economic projections are used as inputs into a state economic projection model which provides an estimate of GSP and other indicators. The State model is then further disaggregated into the statistical subdivisions that make up the region served by the SWIS.

The economic forecasts of the SWIS include projections of population growth, dwelling stock composition and industry growth by sector. This portion of the forecasting system then links the SWIS regional economic forecast with electricity use based on assumptions about appliance penetration and efficiency, weather conditions and separate forecasts of major industrial loads.

4.3 New Major Loads

The demand forecasts incorporate several new major loads identified by the IMO through consultation with the industry. Generally, the IMO considers 20 MW to be the minimum threshold for separate consideration of new major block loads.

To assess the size and likelihood that various projects will proceed and connect to the SWIS, the IMO enters into discussions with developers of these major projects, Western Power and other stakeholders. However, there is always some uncertainty in this assessment relating to:

- decisions associated with the actual development of the projects; and
- the timing for the provision of support infrastructure; in particular, new transmission lines and associated facilities.

Block loads associated with magnetite iron ore projects in the Mid West are the key potential new major loads important to the 2013/14 Capacity Year, but the majority of the new load is dependent on the new Mid West Energy Project southern section from Neerabup to Eneabba 330 kV transmission line. The IMO has considered the following information in forming its view of the likelihood of the transmission line being in place for the 2013/14 summer peak demand:

- While a provision has been made in the State Budget for expenditure for the Mid West Energy Project southern section this is "subject to final regulatory approvals and

Government review of the business case"[2]. These approvals have not been finalised and would be required before works are started.

- Western Power has secured the necessary environmental approvals.
- In early February 2011 the ERA determined that the Mid West Energy Project southern section satisfied the Regulatory Test.
- Western Power has advised that it proposes to submit the New Facilities Investment Test (NFIT) assessment to the ERA during June 2011.
- The ERA has advised the IMO that the NFIT approval process can take up to 160 calendar days or 5 months.
- Following State Government approval of the business case, the construction of the line is estimated to take 26 months. Western Power has indicated that providing approval has been received by December 2011, the line could be completed by the end of February 2014.
- The network connection risks mentioned above are in addition to any timing risks that might be associated with the resource projects.

Based on the information available, the IMO has concluded that the transmission works will not be completed prior to the start of the 2013/14 Capacity Year and that the new load that is reliant on the transmission line is unlikely to be operational during the 2013/14 Hot Season.

Consequently the peak demand forecasts and the Reserve Capacity Requirement for 2013/14 presume no additional new large block loads on the northern transmission system beyond the capacity of the existing network. Some additional load (95 MW) has been allowed for in 2013/14 based on information from Western Power on spare capacity in the existing Mid West network.

The IMO notes that this is the second consecutive year in which it has delayed the introduction of these major Mid West loads in its forecasts due to changes to the schedule in these transmission works. In addition to potential delays in the provision of support infrastructure, the IMO notes that declining economic conditions or commodity prices could cause the relevant projects to be further delayed or cancelled.

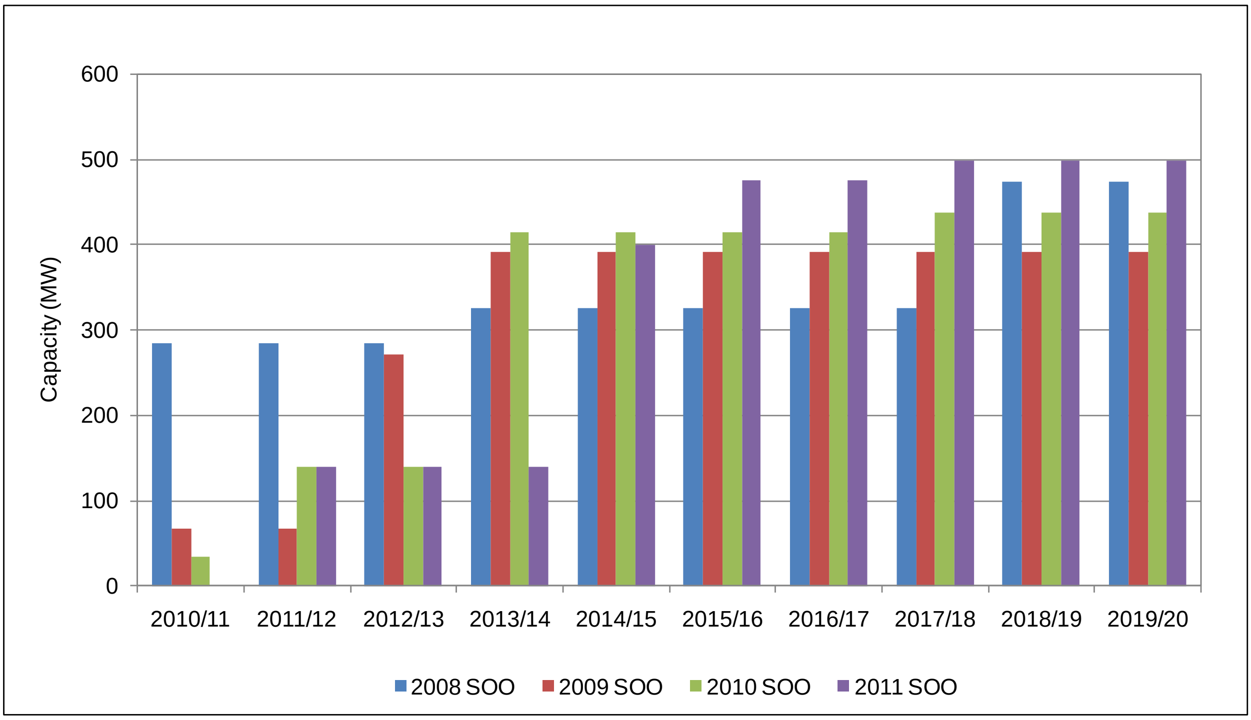
The importance of the new transmission works and the implications for new generators are discussed further in section 7.2 of this report.

While the IMO considers the likely timing and size of these loads using the information available at the time of publication, this process can be extremely problematic. Since 2008, the prediction of new block loads has been extremely lumpy, being dominated by four major mining projects. While one of these loads has now commenced operation, the remaining loads have yet to do so. These projects have appeared to be well advanced at the time of their inclusion in the forecasts. However, large, capital-intensive projects such as these are inherently exposed to delays due to external factors.

[2] 2011-12 State Budget, Volume 2, p620. This can be accessed at http://www.ourstatebudget.wa.gov.au.

The impact of these delays on the peak demand forecasts is shown in Figure 20. This graph shows the total allowance for large loads that has been included in the peak demand forecasts from 2008 to 2011, after excluding any loads that have now commenced operation.

Figure 20 – New Block Load Allowances for Future Projects



The significant year-on-year changes in relation to the three major iron ore projects are explained below.

- The 2008 forecasts, published prior to the commencement of the Global Financial Crisis, included an allowance of more than 250 MW for the three projects, commencing in the 2010/11 Capacity Year.
- By the time of the 2009 forecasts, these projects had been delayed. The forecasts then included 200 MW commencing in the 2012/13 Capacity Year and a further 80 MW in the following year.
- The 2010 and 2011 forecasts have included an allowance for new load to utilise spare capacity in the existing Mid West network. However, delays in project schedules and the schedule for the Mid West Energy project southern section have led to the postponement to 2014/15 of approximately 250 MW for these projects.

4.4 Maximum Demand Forecasts

NIEIR has forecast that the maximum demand will increase at an annual compound growth rate of 3.7% over the ten-year period from 2011/12 to 2021/22. In 2013/14, the year that is the main focus of this report, the maximum demand in a 10% PoE scenario is forecast to be 4,802 MW.

Figure 21 shows the SWIS maximum demand forecast developed by NIEIR for each year in the period to 2021/22 and for each of the 10%, 50% and 90% PoE cases. These forecasts are based on expected economic growth conditions. The peak demand forecasts are tabulated in Appendix 3.

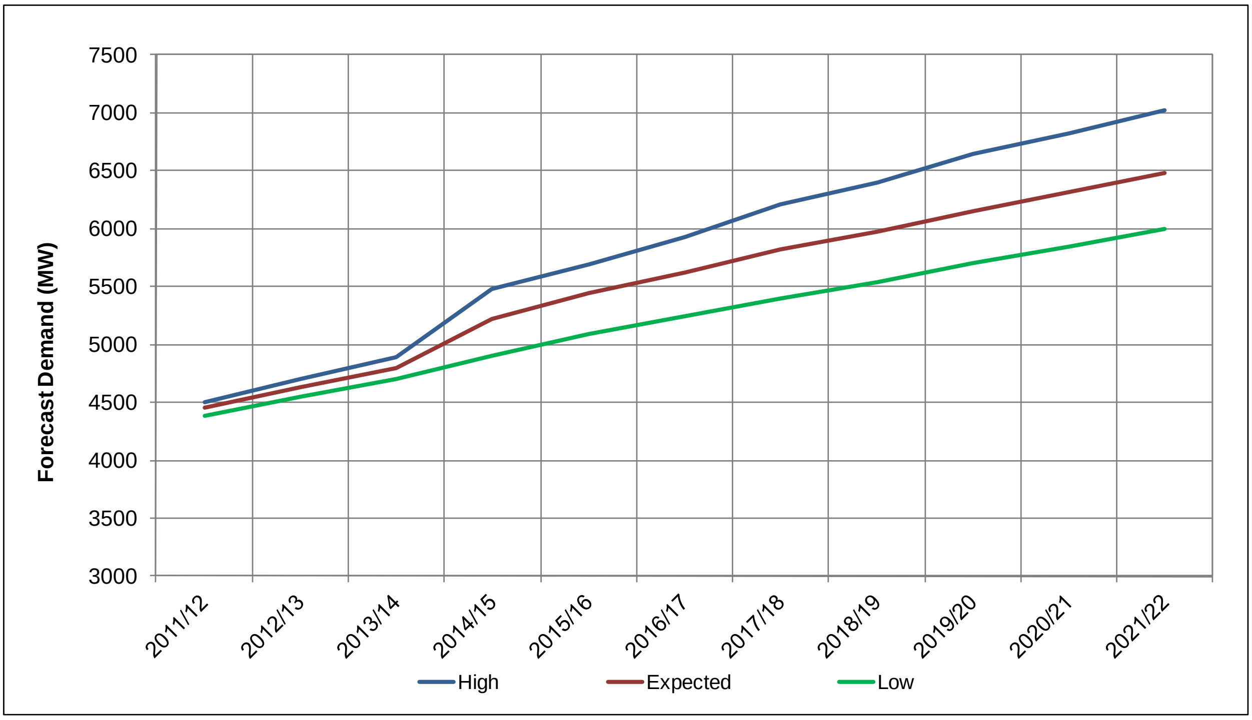
Figure 21 – Forecast Maximum Demand – Expected Economic Growth

The peak demand forecasts include the new block loads identified by the IMO. New block loads have a strong impact on the rate of growth. Presently the IMO has allowed for nearly 500 MW of additional major block loads through to 2021/22.

The sensitivity of maximum demand to temperature can be seen in the differences between the PoE values in Figure 21. For the 2013/14 Reserve Capacity Year, if average (50% PoE) temperature conditions are experienced, the maximum demand is forecast to be 6.6% lower (315 MW) than the 10% PoE forecast. Similarly, if the system maximum demand is experienced on a cooler than average day (e.g. 90% PoE), the maximum demand is forecast to be 11.4% lower (546 MW) than the 10% PoE scenario.

The effect of state economic growth (as forecast by GSP) on the maximum demand forecasts is shown in Figure 22. The 10% PoE forecasts for the Expected, High and Low economic growth scenarios are shown.

Figure 22 – Impact of Economic Growth on Maximum Demand for the 10% PoE Forecast



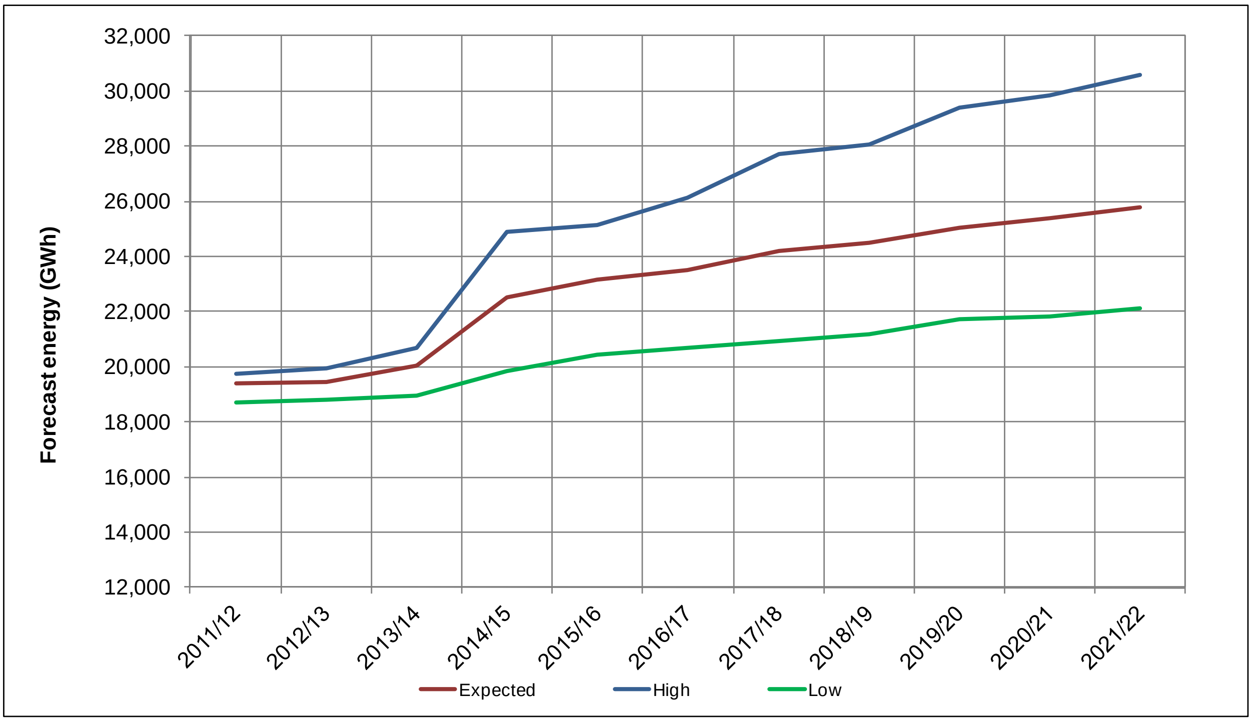
Sensitivity analysis of the economic assumptions on maximum demand shows that if conditions similar to the High economic case are experienced up to 2013/14, the maximum demand is forecast to be approximately 89 MW (1.9%) higher than for the Expected case. Should economic growth be aligned with the Low scenario, the 10% PoE maximum demand is forecast to be approximately 95 MW (2.0%) lower than the Expected case.

4.5 Energy Forecasts

Figure 23 presents the energy consumption forecasts for the SWIS through to 2021/22. Over this period, energy consumption is forecast to grow on average by approximately 2.9% per annum.

Under the High economic growth scenario, the growth in energy consumption is forecast to be 4.5%, while in the Low economic growth scenario energy consumption is forecast to increase at 1.7% per annum on average.

Figure 23 – Forecast Sent-Out Energy



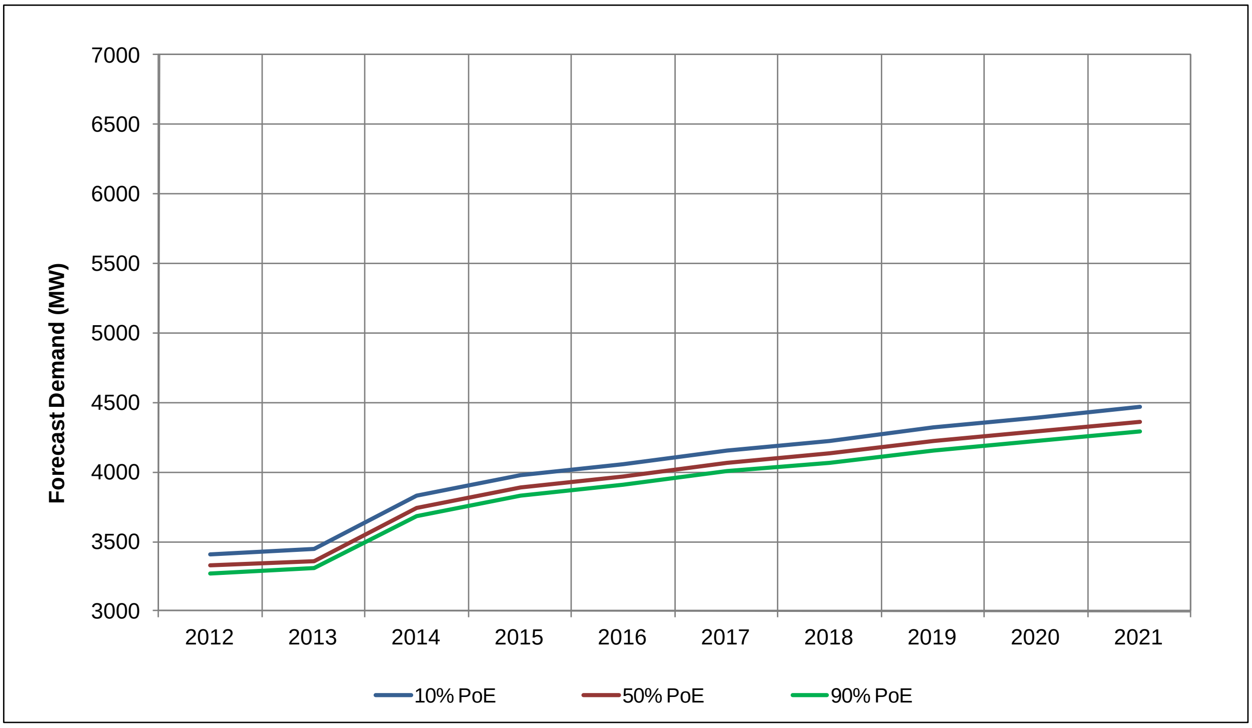
The expected energy requirements of the SWIS in 2013/14 are forecast to be 20,040 GWh. The energy forecasts are tabulated in Appendix 5.

4.6 Winter Maximum Demand Forecasts

Winter peak demand is strongly influenced by the requirement for heating. However, electricity competes directly with gas and other energy sources in this sector so only supplies a portion of total peak demand. Electricity demand for winter heating is substantially lower than the demand for summer cooling, which generally does not have alternative fuel sources.

Because the total demand is lower, the contribution from base industrial and commercial loads during the winter is proportionately higher than in summer. This results in lower temperature variability in winter maximum demand. This lower variability is reflected in Figure 24, which shows the winter maximum demand forecasts for the expected economic growth scenario. As can be seen, the 10% PoE and 90% PoE forecasts are each within 100 MW of the 50% PoE forecasts.

Figure 24 – Winter Maximum Demands



Residential and commercial lighting is a significant component of the maximum demand. These, coupled with demand for domestic heating and cooking, mean that the winter peak occurs in the evening, typically around 6:00 PM.

A number of factors will influence the rate of growth in the winter peak demand including:

- the increased use of reverse-cycle air conditioning for domestic heating;
- the decreased use of domestic wood heaters and non-ducted gas heaters; and
- government programs to replace incandescent lights with more energy efficient units.

Currently, the winter peak demand is forecast to grow at an average rate of 2.9% to reach a level of 4,365 MW in 2021. This is 72% of the forecast summer maximum demand, reinforcing that the SWIS is a summer peaking system.

4.7 Differences between the 2010 and 2011 Forecasts

The forecasts provided this year for 2013/14 are significantly lower than those presented in the 2010 SOO. A number of factors have contributed to the lower demand predictions.

- Delays in the schedule for the Mid West Energy project southern section 330kV transmission line have delayed the expected commencement of approximately 200 MW of new block loads. This delay affects only the 2013/14 peak demand forecast because the IMO has included these loads in the 2014/15 forecasts.
- NIEIR's economic growth expectations for the period to 2013/14 are lower than last year.
- NIEIR has observed from recent data that demand growth in the SWIS attributed to the sale of new air-conditioning systems has not been as high as previously predicted, and has recalibrated its forecasting model.
- NIEIR has forecast the impact of a carbon tax on electricity pricing and on demand. NIEIR has considered that the carbon tax would commence on 1 July 2012 in line with Commonwealth Government policy. NIEIR predicts that this will lead to a dampening of electricity demand, particularly during the first two years after its introduction.

Table 2 compares the 10% PoE maximum demand forecasts prepared in 2010 and 2011.

Table 2 – Comparison of 2010 & 2011 10% PoE Peak Demand Forecasts

Year	2010 10% PoE Forecast (MW)	2011 10% PoE Forecast (MW)	Change in 10% PoE Demand from 2010 to 2011 Forecast (MW)
2011/12	4,793	4,458	-335
2012/13	4,986	4,635	-351
2013/14	5,370	4,802	-568
2014/15	5,601	5,219	-382
2015/16	5,767	5,448	-319
2016/17	5,955	5,625	-330
2017/18	6,168	5,818	-350
2018/19	6,343	5,978	-365
2019/20	6,517	6,154	-363
2020/21	6,689	6,316	-373

The factors listed above have also contributed to lower energy forecasts in the 2011 SOO. The expected energy consumption forecast for 2013/14 of 19,630 GWh is approximately 6.7% below the corresponding forecast in the 2010 SOO.

5. Reserve Capacity Requirements

5.1 Planning Criterion

The IMO is required to set a Reserve Capacity Target for each year at a level which ensures that the two elements of the Planning Criterion are met. The first element relates to meeting demand on the day with the highest maximum demand. The second element ensures that adequate levels of energy can be supplied throughout the year.

The Market Rule[3] in respect of the maximum demand criterion requires the Reserve Capacity Target be set so there is sufficient generation and DSM capacity to:

> *"meet the forecast peak demand (including transmission losses and allowing for Intermittent Loads) supplied through the SWIS plus a reserve margin equal to the greater of:*
>
> *i. 8.2% of the forecast peak demand (including transmission losses and allowing for Intermittent Loads); and*
>
> *ii. the maximum capacity, measured at 41°C, of the largest generating unit;*
>
> *while maintaining the Minimum Frequency Keeping Capacity for normal frequency control. The forecast peak demand should be calculated to a probability level that the forecast would not be expected to be exceeded in more than one year out of ten;"*

The second element of the criterion[4] requires that sufficient capacity be provided to:

> *"limit expected energy shortfalls to 0.002% of annual energy consumption (including transmission losses)".*

The Planning Criterion applies to the provision of generation and DSM capability and does not include transmission reliability planning.

The most stringent element of the Planning Criterion is used to determine the Reserve Capacity Target. In each year of the Long Term PASA Study Horizon, 8.2% of the forecast maximum demand is greater than the capacity of the largest generating unit (measured at 41°C). The 8.2% factor therefore sets the level of reserve margin.

The capacity required to meet the first element (peak demand) is shown in Table 3, contained in Section 5.3. The IMO has refined the previous forecast of the Minimum Frequency Keeping Requirement since last year:

- The forecasts through to 2012/13 were developed following consultation with System Management.
- The values from 2016/17 are as forecast by ROAM Consulting in its Work Package 3 report for the Renewable Energy Generation Working Group (REGWG)[5].

[3] Clause 4.5.9(a) of the Wholesale Electricity Market Rules
[4] Clause 4.5.9(b) of the Wholesale Electricity Market Rules

- A glide path has been used for the intervening years.

The Market Rules require the IMO to undertake a review, at least once every five years, of the planning criterion used to assess system reliability. The last such review was completed in November 2007. The IMO plans to commence the next review in late 2011.

5.2 Role of the Second Element of the Planning Criterion

Although the annual peak demand occurs in summer, the availability of capacity is very important for reliability throughout the year. This is because it is necessary for plant to be regularly taken out of service for maintenance to ensure its ongoing reliability. These plant outages are typically scheduled for lower load periods in autumn, spring and, to a lesser extent, in winter. The outage scheduling process is designed to ensure orderly planning of outages so that sufficient capacity is available at all times.

A key role of the second element of the Planning Criterion, relating to energy shortfalls, is to ensure that there is sufficient plant to accommodate this required maintenance throughout the year. The IMO has retained SKM-MMA to conduct reliability modelling of the SWIS to assess the energy-related element of the Planning Criterion and to develop the Availability Curve, which is given in Section 5.4.

Energy shortfall is tested by modelling the power system in detail across the year. This modelling takes account of the need for plant maintenance and the anticipated level of unplanned (or “forced”) outages. The result is an estimate of the percentage of demand that would not be met due to insufficient supply capacity. The criterion is very stringent, requiring that this “energy shortfall” is less than 0.002% of the annual forecast demand.

For a particular peak demand and generation capacity, the level of energy shortfall across the year would be expected to increase with either:

- an increase in load factor (flatter demand); or
- deterioration in plant availability.

Load factor could increase with an increase in base load, perhaps through new industrial or mining loads, or with higher domestic winter loads, perhaps through a move to reverse-cycle air conditioning rather than gas heating. Increased forced outage rates or planned maintenance would reduce plant availability.

To date, load factors and plant availability have been such that the Reserve Capacity Target has been set by the first element of the Planning Criterion, relating to annual peak demand. For the 2013/14 Capacity Year, the peak demand-based capacity requirement exceeds the energy-based requirement by more than 500 MW.

As indicated above, the present trend suggests that the peak demand forecast will continue to set the Reserve Capacity Target for the immediate future. This is because the load factor

[5] The ROAM Consulting report includes forecasts for four planting scenarios, with Scenario 4 deemed to be the most likely scenario at this stage based on expectations of a moderate carbon reduction policy regime and higher gas prices.For further information, please see http://www.imowa.com.au/regwg

appears to be reducing (with increased summer air conditioning) and plant availability is improving, as reported in section 0.

However, ongoing assessment of the level of unserved energy ensures that changes in plant performance or load shape are being monitored so that the appropriate Reserve Capacity Target is set and reliability of supply is maintained.

5.3 Forecast Capacity Requirements

Table 3 shows the Reserve Capacity Target for each year of the Long Term PASA Study Horizon, as determined from the maximum demand requirement of the Planning Criterion.

Table 3 – Capacity required to satisfy peak demand criterion

(All figures in MW rounded to nearest integer)

Year	Maximum Demand	Reserve Margin	Load Following	Intermittent Loads	Total
2011/12	4458	366	90	16	4,930
2012/13	4635	380	90	16	5,121
2013/14	4802	394	100	16	5,312
2014/15	5219	428	110	16	5,773
2015/16	5448	447	120	17	6,032
2016/17	5625	461	137	17	6,240
2017/18	5818	477	151	17	6,463
2018/19	5978	490	152	17	6,637
2019/20	6154	505	153	17	6,829
2020/21	6316	518	162	17	7,013
2021/22	6481	531	164	17	7,193

The figure of 5,312 MW, as shown in Table 3, is therefore the Reserve Capacity Requirement for the 2011 Reserve Capacity Cycle.

5.4 Availability Curve

The Market Rules include the concept of Availability Classes, where capacity is assigned to a class that reflects the maximum number of hours per year that the capacity is available. This approach recognises the value of DSM but ensures that the lower availability of DSM is considered when assessing system reliability.

Four Availability Classes are defined under the Market Rules:

- Class 1 relating to capacity that is available more than 96 hours every year;
- Class 2 relating to capacity that is available for 72 to 96 hours every year;
- Class 3 relating to capacity that is available for 48 to 72 hours every year; and
- Class 4 relating to capacity that is available for 24 to 48 hours every year.

Class 1 covers generation capacity, while Classes 2 to 4 relate to DSM. Capacity from an Availability Class with higher availability can be used to meet the requirement for an Availability Class with lower availability.

Assuming that the Reserve Capacity Target is just met, the Availability Curve indicates the minimum amount of capacity required to be provided by generation capacity to ensure that the energy requirements of users are satisfied . The remainder of the Reserve Capacity Target can be met by further generation capacity or by DSM.

The Availability Curve information for 2013/14, 2013/14 and 2014/15 is shown in Table 4.

Table 4 – Availability Curve

Availability Curve Information	2012/13 (MW)	2013/14 (MW)	2014/15 (MW)
Market Rule 4.5.12(a):			
Capacity required for more than 24 Hours	4209	4390	4806
Capacity required for more than 48 Hours	4116	4280	4694
Capacity required for more than 72 Hours	4041	4202	4631
Capacity required for more than 96 Hours	4004	4149	4590
Market Rule 4.5.12(b):			
Minimum Generation Required	4280	4402	4828
Market Rule 4.5.12(c):			
Capacity associated with Availability Class 1	4280	4402	4828
Capacity associated with Availability Class 2	0	0	0
Capacity associated with Availability Class 3	0	0	0
Capacity associated with Availability Class 4	842	909	945

The Minimum Generation quantity has increased since last year despite the significant reduction in the peak demand forecasts. The most significant cause of this increase is the updated peak demand and energy forecasts, which reflect a higher load factor than those provided last year. Additional refinement to the model has also been performed, including an updated methodology for modelling the availability of wind farms.

As a result of this increase, the equations in clause 4.5.12(c) determine that the Capacity associated with Availability Classes 2 and 3 is zero. This outcome does not preclude Market Participants from offering capacity into these classes as this capacity also satisfies the requirements of Availability Class 4.

Further, the Availability Curve does not limit the amount of Capacity Credits assigned to any Availability Class where there is intent to bilaterally trade.

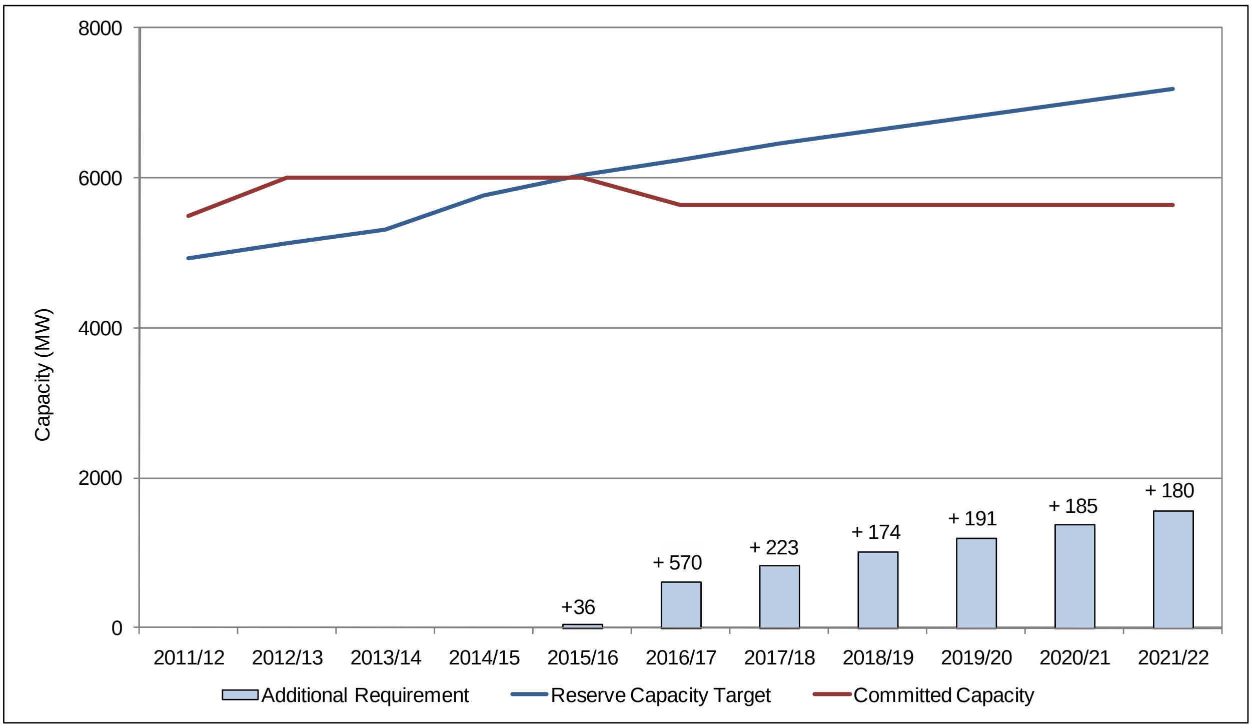
Due to the complexity of the Availability Curve determination, the IMO has provided a more detailed explanation in Appendix 8.

5.5 The Supply-Demand Balance

The supply-demand balance for the period to 2021/22 in the SWIS is presented in Figure 25.

- The blue line in this figure shows the Reserve Capacity Target, increasing from 4,930 MW in 2011/12 to 7,193 MW by 2021/22.
- The red line shows the level of generation and DSM capacity which is in place or committed.
    - For the 2011/12 and 2012/13 Capacity Years, the level of capacity is set by the assigned Capacity Credits. The increase in capacity from 2011/12 to 2012/13 demonstrates the significant commitment to new facilities made in the 2010 Reserve Capacity Cycle. For subsequent years, the level of capacity is assumed to be predominantly constant at the levels shown in Appendix 9. The IMO has forecast a reduction of 361.5 MW in 2015/16 for the decommissioning of Kwinana Stage C, although the timing of this retirement is subject to a commercial decision by Verve Energy.
- The blue bars, show the cumulative requirement for additional capacity to meet the Reserve Capacity Target over the next ten years, while the labels indicate the incremental capacity requirement in each year.

Figure 25 – Required Generation and DSM Capacity



Key points to note from Figure 25 are:

- Sufficient Capacity Credits have been procured to meet the Reserve Capacity Requirement during 2011/12 and 2012/13.

- In-service and committed facilities, prior to the introduction of any new capacity, will provide surplus capacity of 684 MW in 2013/14.
- A further 1,559 MW of Capacity Credits will be needed to meet the increase in the Reserve Capacity Target from 2013/14 to 2021/22 after accounting for the likely retirement of Kwinana Stage C.

This figure illustrates the opportunities, in the longer term, for investment in generation and DSM capacity in Western Australia. More than 1,500 MW of new capacity is forecast to be required over the coming decade to meet load growth, providing opportunities for new and existing investors in the WEM.

Circumstances may change over the period through to 2021/22. Project proponents, investors and developers are advised to make independent assessments of the possible supply and demand conditions.

Graphs of the supply demand balance for High and Low economic forecasts are provided in Appendix 6.

5.6 Opportunity for Investment

A total of 5,312 MW and 5,773 MW of generation and DSM capacity must be available to meet the Reserve Capacity Requirements in 2013/14 and 2014/15 respectively.

This means that capacity already in place or under construction will provide an excess of 684 MW of capacity in 2013/14 and 223 MW in 2014/15, prior to the introduction of any new capacity. 36 MW of new capacity will be required by 2015/16 in order to satisfy the requirement for that year. This is summarised in Table 5.

Table 5 – Opportunity for Investment

	2013/14	2014/15
Existing Generation	5,077 MW	5,077 MW
Existing DSM	154 MW	154 MW
New Generation and DSM Committed for 2012/13	981 MW	981 MW
Plant Closures	216 MW	216 MW
Reserve Capacity Requirement	5,312 MW	5,773 MW
Surplus Capacity	684 MW	223 MW

The most recent Expressions of Interest process identified proposals for 337.25 MW of new Reserve Capacity for the 2013/14 Capacity Year. It should be noted, however, that the proponents of these developments have not necessarily indicated any level of commitment to proceed.

The IMO has analysed these developments based on its understanding of the status of relevant network access and environmental approvals. From this analysis, the IMO considers that potential developments may represent an increase of 156 MW of available Capacity Credits in 2013/14 further increasing surplus capacity.

The IMO has not assessed the probability of each of the potential projects. As with any competitive market, the probability of a proposed project is partly determined by the success of competing projects. Accordingly, for the purposes of this report, the IMO has not determined that any of the potential projects are "probable".

The opportunity for new investment is illustrated in Figure 26 and Figure 27. In these figures "Proposed Projects" relates to the 156 MW of planned projects identified above as "potential".

Figure 26 – Opportunity for Investment – 2013/14

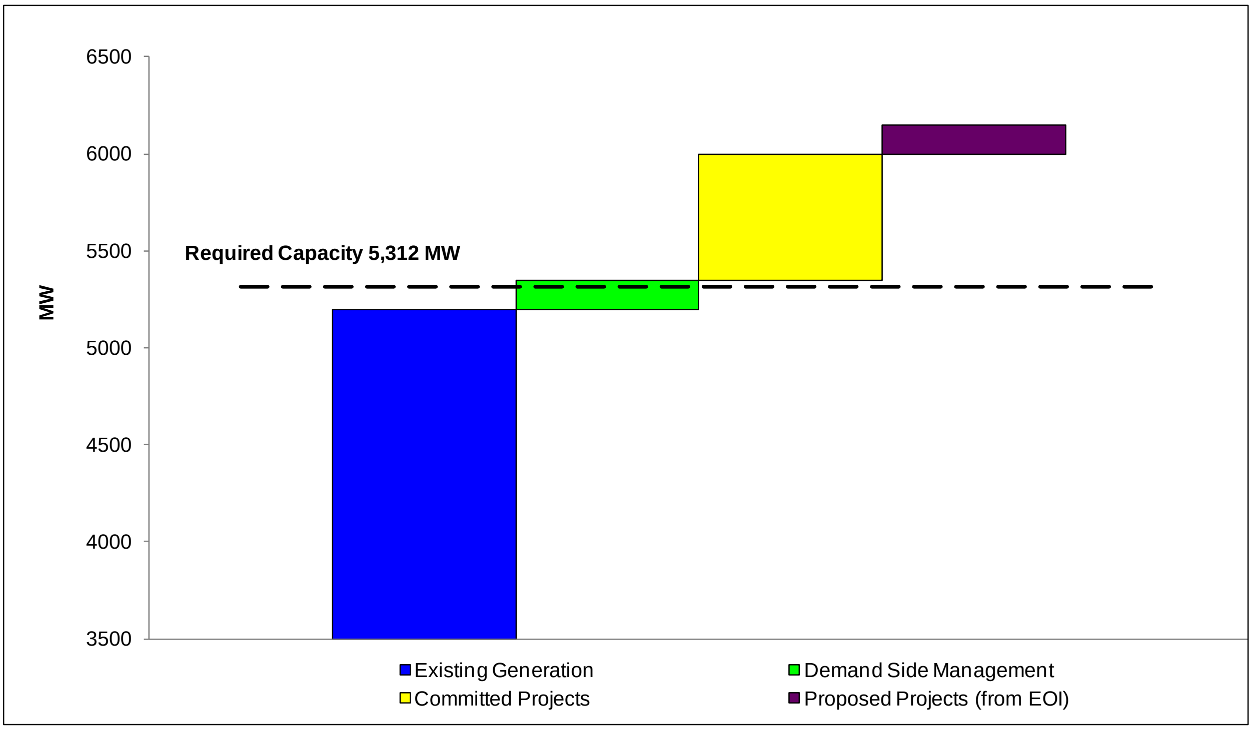
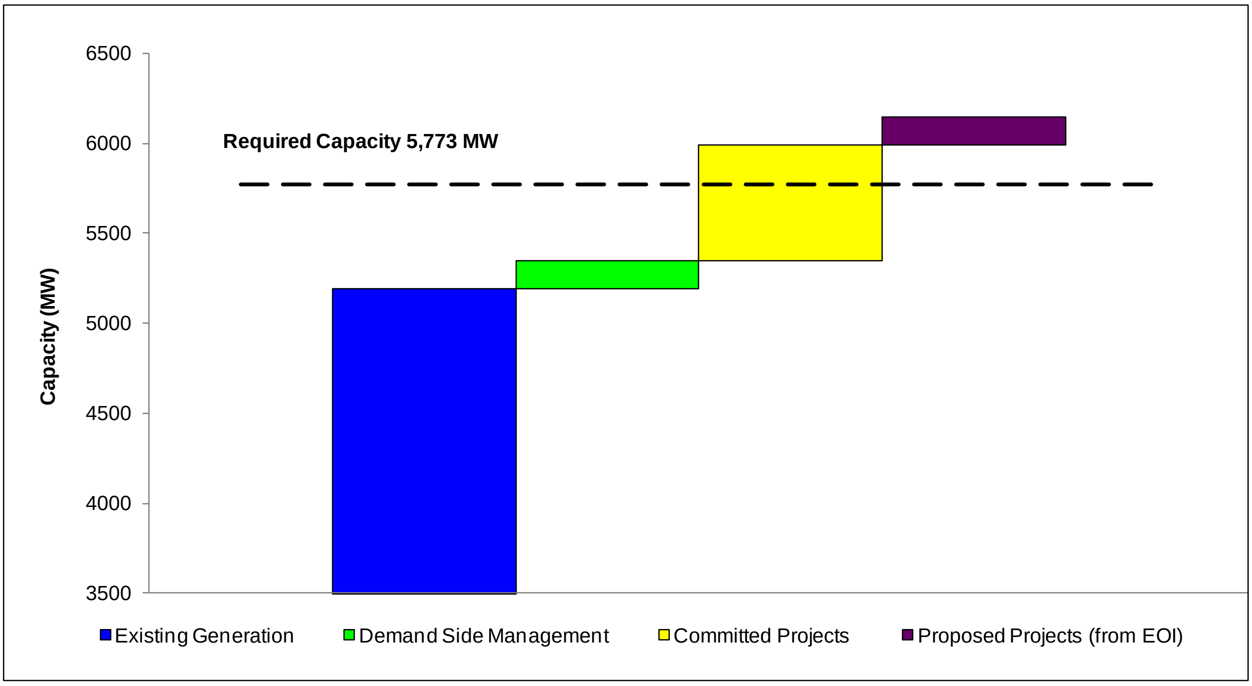


Figure 27 – Opportunity for Investment – 2014/15



6. Next Steps in the Reserve Capacity Process

The next stage in the Reserve Capacity process is for Market Participants to apply for Certified Reserve Capacity and then apply to be assigned Capacity Credits. Certification and Capacity Credits apply only to one year so new applications must be made each year for all existing or planned generation and DSM facilities.

Subject to approval by the Minister for Energy (due 1 July 2011), a number of the dates within the Reserve Capacity Mechanism timeline will change this year as part of amendments to the Market Rules resulting from Rule Change Proposal RC_2010_14[6]. The timetable for the 2011 certification process would then be as follows. Please note that the current dates in the Market Rules are shown in brackets.

- Applications for Certification of Reserve Capacity are now open and must be provided to the IMO by 5:00 PM WST on Wednesday, 20 July 2011. Please note that, subject to approval of RC_2010_14, this date would move to 1 July for Reserve Capacity Cycles from 2012 onwards.
- By 5:00 PM on Friday 19 August 2011 (5 August) the IMO must advise each applicant of the Certified Reserve Capacity to be assigned for the 2013/14 Capacity Year.
- Market Participants with facilities which are granted Certified Reserve Capacity must then apply for Capacity Credits, indicating whether they intend to trade capacity bilaterally or whether they wish to offer the Certified Reserve Capacity into a Reserve Capacity Auction (if one is required). This process must be completed by 5:00 PM on Friday, 2 September 2011 (10 August).
- On Monday 5 September 2011 (11 August), the IMO will advise Market Participants who have indicated their intention to trade their capacity bilaterally how many Capacity Credits will be assigned to their facilities.
- By 5:00 PM on Tuesday 6 September 2011 (18 August), the IMO will advise whether sufficient capacity has been secured through bilateral trades. If the Reserve Capacity Requirement has been met, no Reserve Capacity Auction will be held. If sufficient capacity has not been secured through bilateral trades, the IMO will advise that it will run a Reserve Capacity Auction to secure the outstanding quantity.
- If a Reserve Capacity Auction is required, Market Participants must provide their offers between Wednesday 7 September (22 August) and Wednesday 14 September 2011 (29 August). The IMO would run the Reserve Capacity Auction on Thursday 15 September 2011 (1 September).

Prospective developers should note that for a facility to receive Certified Reserve Capacity, it must fully meet the requirements of Market Rule 4.10.1(c) in respect to network access and environmental approvals. Both of these processes can be lengthy and potential developers are encouraged to contact Western Power and the Department of Environment and Conservation at the earliest opportunity.

[6] See http://www.imowa.com.au/rc_2010_14 for further details.

Disruptions to gas supply in 2008 and 2011 have focused attention on ensuring that appropriate fuel supply arrangements are in place for all facilities. In seeking certification for generation facilities, Market Participants must provide full details of their fuel supply and transport contract arrangements with appropriate supporting documentation. The IMO acknowledges that fuel supply arrangements are often complex and may comprise a portfolio of supply and transport arrangements. Market Participants should develop a presentation that will address potential questions and assist the IMO in undertaking the certification assessment within the short timeframe provided.

Further information on the Certification of Reserve Capacity process[7], and the procedure for Declaration of Bilateral Trades and the Reserve Capacity Auction[8], are available on the IMO website.

[7] http://www.imowa.com.au/crc
[8] http://www.imowa.com.au/market-procedures

7. Key Issues for Potential Developers

7.1 Strategic Energy Initiative

The State Government developed the Strategic Energy Initiative (SEI) in recognition that substantial development and reform is required to deal with emerging issues in the energy industry. The purpose of this initiative is to develop:

- an energy vision for 2031;
- clear goals to guide policy makers and investors;
- a range of strategies for industry and the community to adapt; and
- policy and regulatory frameworks.

An Issues Paper was released in December 2009 which invited the public to submit their views and ideas on the importance of energy and energy supply. Following a public consultation process, the Office of Energy published the *Energy2031* Strategic Energy Initiative Directions Paper in March 2011.

The Directions Paper outlines the future challenges and proposes strategies and actions to meet these challenges. The public consultation process following the release of the Directions Paper has now closed. The Office of Energy expects to have a final paper *Energy2031* released in mid 2011.

More information on the SEI can be found on the Office of Energy website[9].

7.2 Transmission Restrictions on the SWIS

To assist potential developers, Western Power has prepared and published a Generation Connection Capacity Map to provide developers with an indication of the ability of the SWIS to accommodate additional mid-sized generation projects with minimal connection cost. This map was included in Western Power's Annual Planning Report (APR), published in November 2010, and a copy is included in Appendix 10 of the SOO.

As shown in the Generation Connection Capacity Map, the transmission system is nearing capacity in several locations. While this is in part due to the strong increase in overall electricity demand, it is also due to the requests for connections for new generators and to accommodate differing energy flows across the system. The changing economics between various fuel types and high levels of interest in renewable energy generation make it difficult to determine the likely location and size of future power generation projects. Consequently, Western Power is now planning capacity upgrades throughout the transmission system.

The most significant new project under consideration is the proposed Mid West Energy project southern section Neerabup to Eneabba 330 kV double circuit transmission line to provide additional capacity in the Mid West region. This new line could serve a number of planned mineral loads and prospective power generation developments. The conclusion of a satisfactory commercial arrangement between Western Power and a prospective foundation mining

[9] http://www.energy.wa.gov.au/1/3321/3312/about_energy.pm

customer, together with State Government funding approval, will trigger the need for reinforcement.

Transmission access is a key component of the IMO's assessment of applications for Certified Reserve Capacity. It should be noted that when a Market Participant applies for Certified Reserve Capacity in respect of a generation facility that has not yet entered service, the Market Rules require that facility to provide a letter from the relevant Network Operator indicating:

- that it has made a transmission access proposal; and
- that the facility will be entitled to firm access from the nominated service date.

To be certified in the 2011 Reserve Capacity Cycle, a new facility must be capable of fully meeting its reserve capacity obligations by 1 October 2013. Thus, proponents must provide evidence that firm access will be available prior to that date.

As explained in Section 4.3, the IMO considers that the Mid West Energy project southern section will not be completed until 2014. Consequently, the IMO will be unable to assign Certified Reserve Capacity for the 2013/14 Capacity Year to any proposed new generators which rely on the new transmission line.

Generation projects reliant on the new transmission works would be able to apply for certification in future years once network access can be secured.

7.2.1 Considering the Transition to a Constrained Access Network

The WEM design is predicated on an unconstrained network. Analysis for the Planning Criterion is based also on the consistent assumption of an unconstrained network.

This model means that network access is offered for the full operating capacity of the generator irrespective of power system conditions. If the access offer is accepted, the generator then has the right and ability to input energy into the system up to that capacity with the knowledge that the network will be able to accommodate it. This method provides simplicity and certainty for the generator. It is also simpler for the system manager who can operate without the need for a mechanism to curtail certain generators once the system reaches capacity. It should be noted that a few generators in the SWIS have not accepted the cost of upgrades to provide unconstrained network access and in these cases automatic runback of the generator output occurs if network conditions require it.

In the *Energy2031* Strategic Energy Initiative Directions Paper, the Office of Energy has proposed the development of a constrained network access model for the Western Power transmission network. Constrained access models are used in several other electricity markets including the National Electricity Market (NEM), New Zealand, Singapore and PJM (USA)[10].

Under a constrained model, generators calculate and assume the risk of gaining unconstrained access to the network upon completion of their plant rather than being guaranteed of it. A constrained access model may require more generation investment than an unconstrained model to ensure demand is met even if some generation is constrained. However, the

[10] http://www.westernpower.com.au/documents/sustainability/StrategicEnergyInitiativeOfficeEnergy.pdf

arrangement has the potential to deliver more efficient levels of expenditure in network and generation combined.

Transitioning to a constrained access model is also likely to significantly reduce the long lead times entrenched in the current method of obtaining access to the SWIS, which can cause delays in the progress of conventional and renewable power generation technologies. However, a constrained network access model requires a mechanism to resolve dispatch in constraints as well as the allocation of capacity to generators. The development of network constraint equations is a significant undertaking, with some previous estimates indicating many years of development as well as dedicated staff required for ongoing maintenance. A clear benefit resulting from this work is that it will give a clear indication of the limitations of the network under all loading conditions. This will provide a better understanding of the state of the network to help direct planning efforts as well as assisting System Management.

While the shift from an unconstrained to a constrained access model would present significant challenges to administrators, the energy industry and system managers, the long term benefits have the potential to outweigh the short to medium term challenges and costs.

The IMO notes that a transition to a constrained network access model would require significant re-engineering of the WEM, as well as substantial investments in new systems for the IMO and System Management. The IMO estimates that such a policy change would require approximately three to five years to implement.

7.2.2 Network Control Services

The Network Access Code requires Western Power to demonstrate that it has efficiently minimised costs when implementing a solution to remove a network constraint. Prior to committing to a solution, Western Power must consider both network and non-network options.

Both the Network Access Code and Market Rules contemplate the use of Network Control Services (NCS) as non-network options for assessment in the investment decision making process. NCS may be provided by generation and/or DSM. In the case of a generation option, this may take the form of a power station connected to the network which is operated for a short duration during peak network loading periods to provide support to the network. In the case of DSM, specific customers may, by prior arrangement, agree to curtail load, run on-site standby generation or disconnect from the network for short periods to reduce their impact on the network during times of peak network loading.

With the formation of the Wholesale Electricity Market in 2006, it was envisaged that Network Control Services (NCS) would be procured by the IMO using the tender process contained in the Market Rules. However, Rule Change Proposal RC_2010_11[11] is amending this approach such that Western Power directly manages the procurement process allowing the direct entry into an NCS contract by Western Power and a successful tenderer.

Western Power has indicated that it expects potential NCS tender opportunities to be available at various locations including Albany, Geraldton and the Eastern Goldfields.

[11] The amendments to the Market Rules will commence on the 1 July 2011. For more information, see http://www.imowa.com.au/RC_2010_11

7.3 Availability of Fuel for Generation

SWIS power generation is dominated by more conventional plant types, which burn some form of non-renewable fossil fuel. Much of the balance of the Capacity Credits is allocated to renewable energy generators and DSM. As was shown in Figure 7, 51% of Capacity Credits for the 2012/13 Capacity Year are allocated to plant fuelled by gas only or gas-liquids dual fuelled plant. Coal and dual fuelled coal-gas/liquids plant account for a further 38% of Capacity Credits.

In the SWIS, a mixture of coal plant and some gas-fired plant (particularly cogeneration plants and combined cycle gas turbines) is typically used for base-load capacity. Gas-fired plant and some coal plant are used for mid-merit duty while peak-load plants are dominated by gas, dual-fuelled gas-liquids and liquids plant.

While gas accounted for some 63% of electricity generated on a State-wide basis in 2008-09[12], much of this generation was located outside of the SWIS, predominantly in the Pilbara and Goldfields regions. In 2010, gas accounted for approximately 46% of electricity (energy) in the SWIS from thermal generation.

This section provides an overview of the main fuel supplies used in SWIS conventional power generation, being coal and gas, with some commentary on liquids (distillate).

7.3.1 Coal

Western Australia's coal supply for power generation is currently sourced entirely from two operators in the Collie Basin, around 200 km south east of Perth: Wesfarmers Premier Coal and The Griffin Coal Mining Company Pty Ltd (purchased by Lanco Infratech Limited in 2011). The area also hosts the three major coal-fired power stations in the SWIS, the only other coal-fired plant being located at Kwinana. Additional coal reserves are located near Eneabba in the Mid West. There are several other known but undeveloped coal deposits in the South and Mid West, including the Irwin River and Vasse deposits.

Coal production for calendar year 2010 totalled 7.0Mt[13]. More than 70% of the coal produced in Western Australia is consumed in power generation[14]. All Western Australian coal-fired power generation is located in the SWIS, mostly adjacent to or very close to the producing coal mines. In 2009-10 some 546 kt of coal was exported[15], with the balance used largely for mineral processing and industrial applications.

Table 6 shows the coal reserves held by the two Collie operators as at 1 August 2008.

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[12] *Australian Energy Statistics - Australian Energy Update 2010*, Australian Bureau of Agricultural and Resource Economics and Sciences (ABARES), Table F5, http://www.abare-brs.gov.au/publications_remote_content/all-publications?sq_content_src=%2BdXJsPWh0dHAlM0ElMkYlMkYxNDMuMTg4LjE3LjIwJTJGYW5yZGwlMkZEQUZGU2VydmljZSUyRmRpc3BsYXkucGhwJTNGZmlkJTNEcGVfYWJhcmVicnM5OTAwMTY5My54bWwmYWxsPTE%3D

[13] http://www.dmp.wa.gov.au/documents/summary2010.xls

[14] *Australian Energy Statistics - Australian Energy Update 2010*, Australian Bureau of Agricultural and Resource Economics and Sciences (ABARES), Table F5, http://www.abare-brs.gov.au/publications_remote_content/all-publications?sq_content_src=%2BdXJsPWh0dHAlM0ElMkYlMkYxNDMuMTg4LjE3LjIwJTJGYW5yZGwlMkZEQUZGU2VydmljZSUyRmRpc3BsYXkucGhwJTNGZmlkJTNEcGVfYWJhcmVicnM5OTAwMTY5My54bWwmYWxsPTE%3D

[15] *Fremantle Port Authority Annual Report, 2010*

Table 6 – Collie Coal Reserves

Reserves Category	Coal Reserves (Mt)[16]
Measured (high level of confidence)	690
Indicated (reasonable level of confidence)	575
Total Measured and Indicated	**1,265**

Inferred reserves, for which there is a lower level of confidence, are in addition to the reserves indicated in Table 6.

Some of these reserves will be committed under long term contracts. The Collie operators have advised sufficient reserves are available outside of current commitments to provide long term supply for around 1,000 MW of base load coal-fired power generation.

In addition to the coal resources and production in the traditional Collie area, Aviva Corporation Ltd has reported the presence of at least 75 Mt of proved and probable coal reserves at its Central West Coal Project, sufficient to provide fuel over 30 years for a 450 MW power station[17]. However, in an ASX announcement on 11 February 2011, Aviva Corporation indicated that the Environmental Protection Authority (EPA) found the Central West Coal project environmentally unacceptable[18]. In the same announcement, Aviva indicated its intent to appeal the EPA's finding.

7.3.2 Natural Gas Supply

Natural gas first became available from the Perth Basin areas in the Mid West in 1971, delivered to Perth through the Parmelia pipeline. The commencement of production from the much larger capacity North West Shelf production area in 1984 saw significant growth in the penetration of gas in the Western Australian energy mix. This gas, supplied from the Karratha Gas Plant (KGP), was delivered through the Dampier to Bunbury Natural Gas Pipeline (DBNGP).

Gas supply diversity further increased with the commissioning of the Varanus Island gas processing facilities, operated by an Apache Corporation subsidiary, in 1992 and enabled an increase in energy market penetration. Supply is expected to be supplemented in late 2011 by the Devil Creek Gas Plant and again in 2013 by the Macedon project.

Domestic gas (Domgas) consumption in Western Australia has grown significantly from about 100 TJ/d in 1984, when gas from the north west of the state was introduced, to nearly 1000 TJ/d

[16] *Energy WA Coal Reserves,* fact sheet compiled by Office of Energy, 1 August 2008,
[17] *Public Environmental Review, Central West Coal Mine Project,* and *Public Environmental Review, Coolimba Power Station Project*, Aviva Corporation Ltd, 2009
[18] http://avivacorp.com.au/news/asx/epa-report-on-central-west-coal-project-891/

in 2010. The KGP and Varanus Island facilities are estimated to supply more than 97% of Western Australia domgas[19].

Gas is used for all classes of generation (base load, mid-merit and peaking) in the SWIS. Gas is also used extensively in Western Australia as an input to the alumina refining and other industrial processes (including other non-ferrous metals, iron and steel, chemicals, glass, ceramics, concrete and cement). In 2009/10, Western Australia consumed 352 PJ of domestic gas (domgas)[20]. About 870 PJ of LNG was produced during the same period[21]. Other than small quantities used domestically, all of the LNG was produced by the North West Shelf Venture and exported.

The quantity of gas used in the SWIS for power generation has increased in recent years, following the commissioning of new gas-fired generation capacity. Table 7 below lists the gas-fired generation facilities commissioned since 2000.

Table 7 – Gas-Fired Generation Commissioned Since 2000

Facility	Type	Year of commissioning	Nameplate capacity (MW)
Worsley Alumina	Cogeneration	2000	120
Verve Cockburn	CCGT	2003	240
Alinta Pinjarra (2 units)	Cogeneration	2006/07	280 (140 per unit)
Alinta Wagerup (2 units)	OCGT	2007	380 (190 per unit)
NewGen Kwinana	CCGT	2008	320
NewGen Neerabup	OCGT	2009	330
Western Energy Kwinana Swift	OCGT	2010	120
Verve Kwinana HEGTs (2 units)	OCGT	2011*	200

* Due to be commissioned in October 2011.

Several gas developments in the coming years are anticipated to supplement the existing domgas production. Figure 28 summarises the existing, committed and announced potential domgas processing capacity in Western Australia.

[19] *Western Australia Gas Market Study*, Wood Mackenzie Report, 26 March 2010 (from ACCC website), http://www.accc.gov.au/content/index.phtml/itemId/922104/fromItemId/401858/display/application, Application Appendix 1, pp22-23.
[20] *Western Australian Mineral and Petroleum Statistics Digest 2009-10*, Department of Mines and Petroleum. Conversion factor of 38.2 MJ/m^3 used on http://www.santos.com/conversion-calculator.aspx.
[21] *Western Australian Mineral and Petroleum Statistics Digest 2009-10*, Department of Mines and Petroleum. Conversion on http://www.santos.com/conversion-calculator.aspx

Please note that the graph only shows domgas production capacity and does not provide a forecast of actual production, nor indicate contractual commitments for gas produced form those plants.

Within the graph, the IMO has split the various projects into "expected" and "speculative". A full explanation of these classifications is shown in Table 7, accompanied by a detailed summary of available information related to current and future domestic gas production and processing capacity.

Figure 28 – Existing, Committed and Potential WA Domgas Processing Capacity

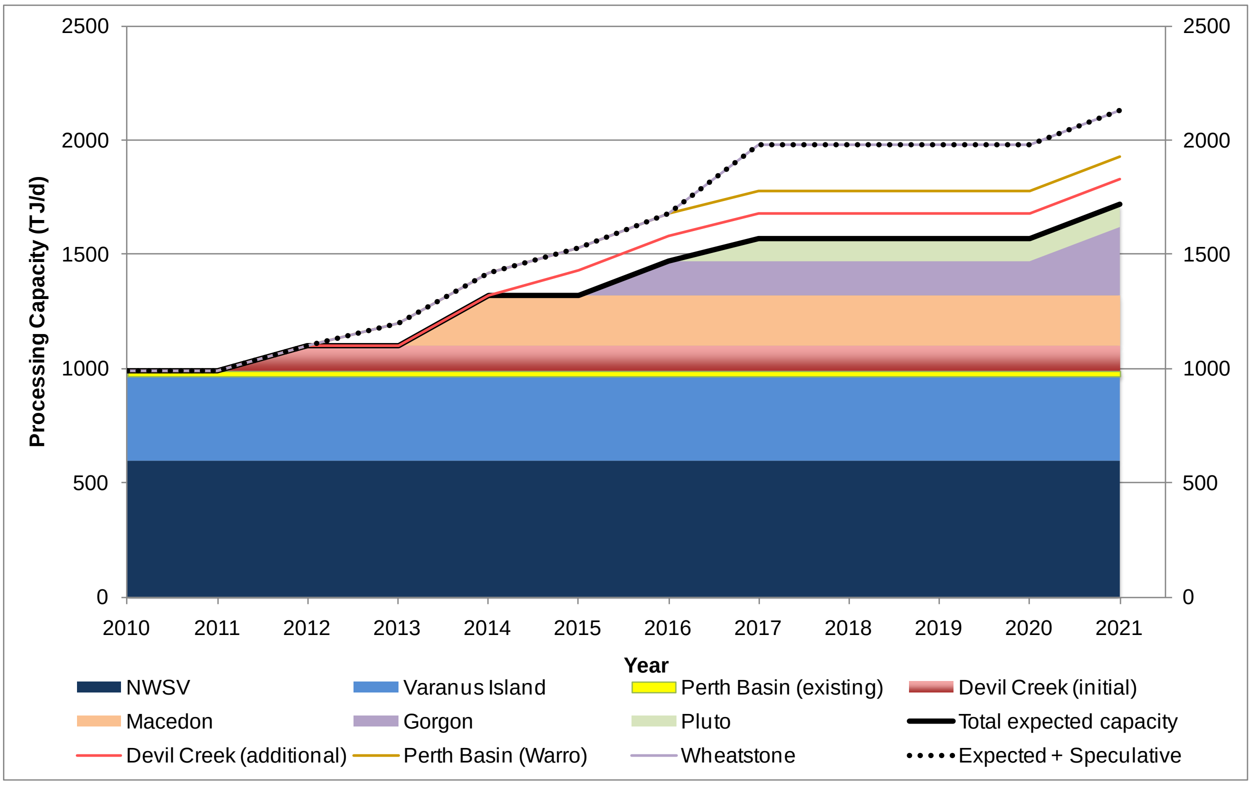

Table 8 – Summary of Available Information Related to Current and Future Domestic Gas Production and Processing Capacity

Information	IMO Comments
North West Shelf Venture (NWSV)	
• LNG project, operated by Woodside.	The IMO expects domgas supply from NWSV to continue at or near current levels for the next 10 years, provided that commercial terms can be reached, in order to maintain utilisation of existing facilities.
• Current domgas processing capacity around 600 TJ/d. *Source: Woodside Website*[22]	
• 2010 average output was approximately 580 TJ/d. *Source: Woodside, Fourth Quarter Report, 2010*[23]*.*	
• The original domgas obligation for the project is likely to be satisfied by the end of 2013. *Source: ACCC website, "*North West Shelf – Authorisations – A91220 – A91223*", Application Attachment 1 ("*Western Australia Gas Market Study*")*[24]*.*	
• Additional developments, including the North Rankin redevelopment and the Greater Western Flank fields, are anticipated to enable production to be maintained "beyond 2020". *Source: Woodside 2010 Annual Report, page 25.*	
Varanus Island	
• Operated by Apache, all gas for domestic use.	With current output near plant capacity and the Halyard and Spar fields supplementing gas production, the IMO expects Varanus Island production could be maintained at or near current levels for 7-10 years.
• Current processing capacity around 365 TJ/d, currently producing at this rate. *Sources: Speech by Premier Colin Barnett to Baker Institute, 13 Apr 2010*[25]*; Apache Corporation website*[26]*.*	
• Future production of the Halyard & Spar fields will sustain domgas production in the coming years. • Halyard commenced production in June 2011, with Spar expected to be online in 2012. *Source: Santos Website.*[27]	
Devil Creek	

[22] http://www.woodside.com.au/our-business/north-west-shelf/onshore-production-facility/productionfacilities/pages/production-facilities.aspx
[23] http://www.woodside.com.au/Investors-Media/Announcements/Documents/21.01.2011%20Q4%202010%20Quarterly%20Report.pdf
[24] *Western Australia Gas Market Study*, Wood Mackenzie Report, 26 March 2010 (from ACCC website), http://www.accc.gov.au/content/index.phtml/itemId/922104/fromItemId/401858/display/application, Application Appendix 1, pp22-23.
[25] http://www.mediastatements.wa.gov.au/Pages/default.aspx?ItemId=133337&
[26] http://www.apachecorp.com/Operations/Australia/Production.aspx
[27] http://www.santos.com/Archive/NewsDetail.aspx?p=121&id=1267 and http://www.santos.com/exploration-acreage/development-projects/spar.aspx.

• Operated by Apache, all gas for domestic use.	The IMO considers 110 TJ/d could be maintained for at least 7 years. Timing of the increase to 220 TJ/d is uncertain and the IMO has classified this as speculative from 2015.
• Plant under construction, due online in quarter four of 2011. *Source: Apache Presentation, May 2011*[28]*.*	
• Plant being built to capacity of 220 TJ/d, with initial output of 110 TJ/d. Remaining plant capacity "will provide for the expected future increase in demand for natural gas in WA". *Source: Devil Creek Development Project website*[29].	
• Apache has a supply contract with CITIC Pacific's Sino Iron project is for 7 years, commencing in the second half of 2011. *Source: Santos news release, 7 Jan 2009, "*Santos signs US$585 million Sino Iron gas supply contract*".* • The expected life of the Reindeer field is 10 to 14 years, with the expected life of the Devil Creek Development being 25 years. It is anticipated that additional gas fields would be connected in the future. *Source: "*Devil Creek Development Project, Draft Public Environmental Review, Part A – Onshore*", June 2008.*	
Macedon	
• Project operated by BHP Billiton, all gas to be for domestic use. Includes gas from Macedon field and gas reinjected into the field from the Pyrenees development for future recovery. Incidentally, the Pyrenees development has an estimated production life of 25 years. *Source: BHP Billiton press release, 1 Mar 2010, "*First Oil Production from Pyrenees Development, Offshore Western Australia*".*	The IMO expects first gas to be produced in 2014. The IMO considers that production of 220 TJ/d could be sustained for 7-10 years.
• Project was sanctioned in September 2010, first gas expected in 2013. *Source: BHP Billiton press release, 24 Sept 2010, "BHP Billiton Approves Macedon Gas Development in Western Australia".* • The Macedon project has a capacity of approximately 220 TJ/d (based on 200mmcf/d). *Source: Apache Presentation, May 2011*[30]*.*	
• The project is anticipated to have a lifespan of 20 years, which may be extended if additional reserves or reservoirs are discovered. *Source: Macedon Gas Project Environmental Protection Statement, July 2010*[31]*.*	

[28] http://files.shareholder.com/downloads/APA/1282234980x0x469895/6c5e8d07-a5ec-4cdf-8f75-43a293236bbb/Apache_InvestorDay_20110517-06-Australia.pdf
[29] http://www.apachedcdp.com.au/index.php?option=com_content&task=view&id=13&Itemid=28
[30] http://files.shareholder.com/downloads/APA/1282234980x0x469895/6c5e8d07-a5ec-4cdf-8f75-43a293236bbb/Apache_InvestorDay_20110517-06-Australia.pdf
[31] http://www.bhpbilliton.com/bbContentRepository/docs/macedonFinalEpsEpa.pdf

<table>
<tr><th colspan="2">Gorgon</th></tr>
<tr><td>• LNG project, operated by Chevron. LNG contracts for approximately 90% of production have been signed for between 15 and 25 years.
Source: Chevron website [32].</td><td rowspan="3">The IMO expects that 150 TJ/d will commence in 2015, with an additional 150 TJ/d available in 2021, in line with the listed references.</td></tr>
<tr><td>• 2000 PJ of gas reserved for domestic use. Minimum of 300 TJ/d processing capacity required as part of the State Agreement, unless commercially unviable. First gas expected by end of 2015 or at the time of first LNG production from the third train, whichever is earlier.
Source: Department of State Development website[33].</td></tr>
<tr><td>• “Chevron says it does not expect to be delivering its full quota of 300 TJ/day until 2021 because of an expected oversupply in the domestic market”.
Source: The West Australian, 16 June 2009, “Barnett opens door to gas reserve changes”, published in Domgas Alliance submission to Strategic Energy Initiative[34].</td></tr>
<tr><th colspan="2">Pluto</th></tr>
<tr><td>• LNG project, operated by Woodside. Initial LNG development has processing capacity of 4.3 million tonnes per annum (Mtpa), with Woodside continuing to pursue expansion plans. LNG contracts have been signed for 15 years with Kansai Electronic and Tokyo Gas.
Source: Woodside, Pluto Fact Sheet, Q3 2010[35].</td><td rowspan="4">The IMO considers that around 100 TJ/d could become available during 2017.</td></tr>
<tr><td>• Under the 15% domestic gas reservation policy, Woodside’s obligation is for domgas supply to commence 5 years from the first LNG production, providing it is commercially viable.
Source: Statement by WA Premier, 8 Dec 2006, “Woodside commits to domestic gas reservation policy”.</td></tr>
<tr><td>• The Pluto project is expected to deliver its first LNG in March 2012.
Source: Woodside’s Pluto Cost and Schedule Update, 17 June 2011[36].</td></tr>
<tr><td>• The size of a future domgas processing plant is not yet certain, though estimates suggest it would be around 100 TJ/d.
Sources: Energy2031 Strategic Energy Initiative Directions Paper; Modelling greenhouse gas emissions from stationary energy sources, report by Acil Tasman for the Department of Climate Change and Energy Efficiency[37].</td></tr>
</table>

[32] http://www.chevronaustralia.com/ourbusinesses/gorgon/thegasmarket.aspx
[33] http://www.dsd.wa.gov.au/7599.aspx
[34] http://www.erawa.com.au/cproot/8515/2/20100503%20D29252%20DBNGP%20-%20Submission%208%20-%20Annexure%205%20-%20Domgas%20Alliance%20WA%20State%20Energy%20Initiative%20-%20Domestic%20Gas%20Action%20Plan%20Submission%20to%20the%20SEI.pdf
[35] http://www.woodside.com.au/Our-Business/Pluto/Documents/PlutoFactSheetQ32010.pdf
[36] http://www.woodside.com.au/Investors-Media/Announcements/Documents/17.06.2011%20Pluto%20Cost%20and%20Schedule%20Update.pdf
[37] http://www.climatechange.gov.au/publications/projections/~/media/publications/projections/acil-tasman-stationary-energy-modelling-pdf.pdf

<table>
<tr><th colspan="2">Perth Basin</th></tr>
<tr><td>

- Latent Petroleum pursuing development of Warro tight gas field in Perth Basin. Target production from the field is 100 TJ/d.
Source: PetroleumNews.net, 7 May 2010, "Latent likes chances of tight gas success." [38]
- Production is expected to commence in 2013/2014.
Source: Latent Petroleum Website[39].

</td><td rowspan="2">Due to technological challenges, the IMO has classified the Warro project as speculative at this stage. Existing Perth Basin production is expected to remain relatively constant.</td></tr>
<tr><td>

- AWE and Origin continue occasional drilling operations in the Perth Basin.

</td></tr>
<tr><th colspan="2">Wheatstone</th></tr>
<tr><td>

- LNG project, operated by Chevron. Heads of Agreement signed with Tokyo Electric Power Company (TEPCO) to supply LNG for 20 years.
Source: Chevron news release, 5 Dec 2009, "Chevron and TEPCO Sign Major Wheatstone LNG and Equity Deal".

</td><td rowspan="3">The IMO has conservatively classified the domestic gas from the project as speculative in the absence of a final investment decision or a State Agreement. The IMO anticipates these will be finalised prior to the publication of the 2012 SOO and, if favourable, will re-classify this project as committed.</td></tr>
<tr><td>

- 80% of the LNG projected capacity has been contracted.
Source: Chevron, Frontier Magazine, Spring 2010[40].
- Chevron reached agreement with Apache and KUFPEC for Julimar and Brunello gas to be produced through the Wheatstone LNG facility.
Source: Chevron news release, 22 Oct 2009, "Chevron Welcomes New Partners to Wheatstone Project".
- A Joint Operating Agreement has been signed between Chevron, Apache and Kuwait Foreign Petroleum Exploration Company (KUFPEC). Final investment decision expected in the second half of 2011.
Sources: Chevron's Frontier Magazine, Summer 2011 and Australia Fact Sheet[41].
- EPA granted conditional environmental approval for the project on 15 June 2011.
Source: EPA Media Statement[42].

</td></tr>
<tr><td>

- First domestic gas production is estimated in 2016. Estimated domgas capacity of 200 TJ/d.
Source: Chevron website.[43]

</td></tr>
</table>

[38] http://www.petroleumnews.net/storyview.asp?storyid=1135396&sectionsource=s90&highlight=latent
[39] http://www.latentpet.com/warro.asp
[40] http://www.chevronaustralia.com/media/publications.aspx
[41] http://www.chevron.com/Documents/Pdf/AustraliaFactSheet.pdf
[42] http://www.epa.wa.gov.au/News/mediaStmnts/Pages/Report1404-Wheatstone.aspx?pageID=298&url=News/mediaStmnts
[43] http://www.chevronaustralia.com/media/speeches.aspx?NewsItem=a9ec6744-1f9e-482d-adea-c4a91a2b28fa and http://www.chevronaustralia.com/media/speeches.aspx?NewsItem=d4464b2b-7cb1-430a-b83a-d43ae652ea49

7.3.3 Gas Transportation

Gas is transported into the SWIS via three routes:

- DBNGP, which receives gas from the KGP, Varanus Island and Devil Creek (from late 2011) facilities, and which will receive gas from other new offshore developments when they are commissioned, such as Macedon and Gorgon;
- Parmelia Pipeline from the Perth Basin fields, which is also connected to the DBNGP at Mondarra; and
- Goldfields Gas Pipeline (GGP), which is connected to the Varanus Island facilities and with the DBNGP at the GGP inlet. The GGP delivers gas to the Goldfields region where some of the power generation is connected to the SWIS via Western Power's 220 kV transmission line.

7.3.3.1 Dampier to Bunbury Natural Gas Pipeline

Following three expansion projects, the "full haul" (to the south west) capacity of the DBNGP is 845 TJ/d, with typical utilisation at around 80%[44]. The actual capacity of the pipeline varies daily with a number of factors including ambient temperature, gas quality and the pressure at which producers deliver gas into the pipeline. While the firm capacity is fully contracted to shippers[45], interruptible "spot" capacity is available on most days.

The owner and operator, DBP Transmission, advises that completion of "looping" (duplication) of the pipeline would add approximately 80 TJ/day of firm full haul capacity. However, this will only be built in response to firm long term contracts. Further expansion beyond the completion of the first looping of the pipeline is possible by adding compression and further loops, subject to agreement on commercial terms[46].

7.3.3.2 Parmelia Pipeline

This pipeline, owned and operated by APA Group, has a current capacity of approximately 65 TJ/d, of which there is currently a portion of uncontracted capacity available. The pipeline's capacity can be expanded further through compression and/or looping. The pipeline delivers gas from multiple Perth Basin inlet points and from the North West Shelf (through the DBNGP interconnect at Mondarra). The Pipeline extends from Dongara, through Perth and Kwinana to Pinjarra, south of Perth[47].

7.3.3.3 Goldfields Gas Pipeline

The pipeline, majority-owned and operated by APA Group, has a current capacity of approximately 150 TJ/day, which is currently fully committed. The pipeline's capacity can be expanded further through compression and/or looping, subject to agreement on commercial terms[48].

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[44] Discussions with DBP Transmission, capacity includes Full Haul and Part Haul
[45] Data for DBNGP gathered from Gas Supply and Emergency Management Committee Report to Government, Sept 2009 (http://www.energy.wa.gov.au/cproot/1576/2/Mitigation%20Full%20%20Report%20-%20Evans%20_%20Peck.pdf) and discussion with DBP Group
[46] Provided by DBP Transmission
[47] Provided by APA Group
[48] Provided by APA Group

7.3.4 Gas Storage

Gas storage capacity can enhance the security of gas supply and lessen the impact of upstream disruptions to gas supply. The development of a commercial gas storage facility was recommended by the Gas Supply and Emergency Management Committee that reviewed the security of Western Australia's gas supplies following two significant gas supply disruptions in 2008. Sufficient volumes of gas storage can reduce the pressure on liquid fuel supplies immediately following a major gas supply disruption.

APA Group has recently committed to an expansion of its commercial underground gas storage facility at Mondarra[49], which is connected to both the Parmelia Gas Pipeline and the Dampier Bunbury Pipeline. This expansion project, which is due for completion in the first quarter of 2013, has been underwritten by a 20-year commercial arrangement with Verve Energy covering a significant portion of the increased storage capacity.

The expansion of the facilities will significantly increase the commercial storage capacity of the facility by more than five times its current level to 15 PJ. It is anticipated that the facility will be able to provide in excess of 120 TJ/day of gas supply for several weeks upon completion of the project. Verve Energy's contract arrangements will provide it "with up to 90 TJ/d, enabling an additional 800 megawatts of gas-fired generation to operate during peak demand periods for up to 60 days"[50].

7.3.5 Liquid Fuel

Diesel is the dominant liquid fuel used for power generation in the SWIS. Generators contract directly with the oil companies to supply their requirements. Diesel is typically used in the SWIS for short-term peaking generation.

Oil companies tend to maintain only limited stocks of around 10-17 days consumption[51], so prolonged use of diesel for generation of significant quantities of energy may place strains on the supply chain unless mitigations are put into effect ahead of the requirement. It should be noted that the swift mobilisation of diesel supplies from Singapore following the 2008 Varanus Island incident enabled local inventories to be supplemented at short notice.

7.4 Potential Changes for Dual-Fuelled Facilities

As mentioned previously, dual-fuel plant played an important part in maintaining system reliability and security during the Varanus Island incidents in 2008 and 2011. However, the IMO recognises that the Market Rules currently provide no incentive for generators that are capable of running on more than one fuel type, yet require that additional Reserve Capacity tests are performed on such facilities.

The IMO notes that the *Energy2031* Strategic Energy Initiative Directions paper proposes the development of incentives for investment in dual fuel equipped electricity generation facilities.

[49] http://www.openbriefing.com.au/AsxDownload.aspx?pdfUrl=Report%2FComNews%2F20110526%2F01183952.pdf and http://www.verveenergy.com.au/subContent/mediaReleases/mediaReleasesArticles/MONDARRA_GAS_STORAGE_EXPANSION.html.

[50] http://www.mediastatements.wa.gov.au/Pages/default.aspx?ItemId=140541&page=2

[51] *Maintaining Supply Reliability in Australia*, Australian Institute of Petroleum, April 2008

As noted in its submission to the Directions Paper[52], the IMO has recommended a design concept to the Office of Energy and is awaiting feedback. The IMO estimates that, once a policy decision is made, the design and implementation for this mechanism would take less than 12 months.

7.5 Opportunities for the Provision of System Restart Ancillary Services for 2013/14

System Management has advised the IMO that it is aiming to procure a new System Restart service to commence on 1 July 2013 following the expiry of an existing contract. This service would be supplied by a Scheduled Generator that can start without needing to draw power from the transmission network and can then be used to energise the power system.

System Management has indicated that the following features would be preferred in a potential provider for this service:

- at least 50 MW of installed capacity;
- connected to the 132 kV transmission network; and
- located in the Collie/Bunbury area at one of the following substations: Muja, Bunbury Harbour, Picton, Marriot Rd, Kemerton, Worsley or Western Collieries.

Interested parties may contact Mr Brendan Clarke at System Management for further information.

7.6 Incentives for Renewable Generation and Carbon Emission Reduction

The Federal and State Governments have announced numerous mechanisms designed to increase the proportion of energy produced by renewable generation and reduce carbon emissions. Some of these initiatives are listed below. This list is not exhaustive, and the IMO recommends that proponents perform their own research into the schemes below and their eligibility for any associated funding.

- The Federal Government has indicated its intent to introduce a carbon tax from 1 July 2012, with a transition to a cap-and-trade emissions trading scheme after three to five years. Details of the arrangements are under development, but further information is available from the Department of Climate Change and Energy Efficiency[53].
- The Federal Government's Renewable Energy Target (RET) Scheme seeks to encourage additional renewable energy generation to meet the Government's commitment for 20% of Australia's energy demand to be supplied by renewable sources by 2020. Renewable energy generators receive incentives in the form of Renewable Energy Certificates (RECs) that can be traded. Further information is available from the Office of the Renewable Energy Regulator[54].
- The Solar Flagships Program forms part of the Federal Government's Clean Energy Initiative and seeks to assist in the establishment of 1,000 MW of solar generation capacity throughout Australia. No projects from Western Australia were among the

[52] http://www.energy.wa.gov.au/cproot/2631/2/Independent%20Market%20Operator.pdf
[53] http://www.climatechange.gov.au/government/initiatives/multi-party-committee.aspx
[54] http://www.orer.gov.au/

shortlisted projects for Round 1 of this program, but Round 2 is currently expected to be held in 2013-14. Further information is available from the Department of Resources, Energy and Tourism[55].

- The State Government's Low Emissions Energy Development (LEED) Fund has been established to support the development of low-emission electricity generation technology. Applications for Round 4 funding opened on 18 May 2011, with up to $8 million available for allocation to suitable projects. Applications close on 29 June 2011. Further information is available from the Department of Environment and Conservation[56].

7.7 Potential Changes for Intermittent Generators

The Market Advisory Committee (MAC) convened the Renewable Energy Generation Working Group (REGWG), which was requested to:

- identify priority issues arising, or that could arise, from increasing penetration of intermittent renewable energy generation in the SWIS;
- determine the appropriate framework for analysis of issues and options for resolving them against the Market Objectives; and
- submit its assessment, analysis and conclusions in a report to the MAC.

The final meeting of the REGWG was held on the 2 September 2010. A number of potential changes to the Market Rules have been proposed following the work of the REGWG:

- Rule Change Proposal, RC_2010_25[57] was submitted by the IMO, proposing a percentile method to allocate Capacity Credits to Intermittent Generators.
- Griffin Energy proposed an alternative method to allocate Capacity Credits for Intermittent Generators (RC_2010_37)[58]. This Rule Change Proposal is being considered simultaneously with RC_2010_25.
- A pre-rule change discussion paper (PRC_2010_27)[59] on Ancillary Services Payment Equations was most recently presented to the MAC by the IMO on 8 June 2011. The proposal would amend the allocation of Load Following costs, increasing the share that would be paid by Intermittent Generators. The MAC broadly endorsed the IMO's recommendation to submit this into the Rule Change Process in conjunction with the introduction of a Rule Change Proposal to introduce a competitive Load Following market, which is being developed through the Market Evolution Project (see Section 7.12).

Draft Rule Change Reports for RC_2010_25 and RC_2010_37 are currently being developed and are due to be published on 24 June 2011. PRC_2010_27 is expected to be submitted into the Rule Change Process around August 2011.

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55 http://www.ret.gov.au/energy/clean/cei/sfp/Pages/sfp.aspx
56 http://www.dec.wa.gov.au/content/view/6499/2369/
57 http://www.imowa.com.au/RC_2010_25
58 http://www.imowa.com.au/RC_2010_37
59 http://www.imowa.com.au/MAC_36

Parties considering development of wind farms, and other intermittent generation options, should familiarise themselves with the details of the Rule Change proposals and the potential impact on new facilities. The Rule Change Process provides stakeholders with opportunities for consultation.

7.8 Demand Side Management

DSM is the curtailment of demand upon dispatch. DSM is an integral part of the WEM and can be assigned Capacity Credits.

Experience gained since commencement of the market has identified a number of operational issues with DSM, and as a result the IMO submitted Rule Change proposal (RC_2010_29[60]) in December 2010. The final Rule Change report is scheduled to be published on 17 June 2011. Provisional commencement dates for the proposed amendments are nominally 1 June 2011 and 1 Oct 2011.

Market Participants considering offering DSM into the WEM are encouraged to familiarise themselves with the amending Market Rules as outlined in the Final Rule Change report.

7.9 Review of the Maximum Reserve Capacity Price Methodology

The Market Rules require the IMO to undertake a review at least once in every five years of the methodology and process followed to determine the Maximum Reserve Capacity Price.

The MAC has convened the Maximum Reserve Capacity Price Working Group (MRCPWG) to undertake this review. The MRCPWG is nearing the end of its review and has recommended a number of changes in the methodology. Preliminary analysis indicates that the recommended changes, considered in isolation, may result in a reduction of 10-15% in the Maximum Reserve Capacity Price for future determinations.

The MRCPWG will conclude its scope upon presentation of a Procedure Change Proposal and full impact assessment to the MAC. It is anticipated that these will be presented at the July 2011 MAC meeting. The Procedure Change Process allows for submissions from industry to be considered prior to acceptance of amendments to the new Market Procedure.

Stakeholders can find more information on the proceedings of the MRCPWG on the IMO's website[61].

7.10 Change to the Reserve Capacity Mechanism Timeline

The four-month window of entry for new entrant generators has been brought forward for the 2012/13 Capacity Year and future Capacity Years to start on 1 June, with all capacity to be fully available no later than 1 October each year. Previously, the timeframe for new capacity to enter the Reserve Capacity market was a four-month window from 1 August to 30 November.

[60] http://www.imowa.com.au/RC_2010_29
[61] http://www.imowa.com.au/MRCPWG

The IMO considered that the previous dates for entry of new capacity may have encouraged inappropriate risk taking. For example, a developer may have taken an optimistic view and brought a project forward in order to meet the 30 November deadline. However, minor delays could then have resulted in the capacity being unavailable for some or all of the Hot Season.

This matter was dealt with under Rule Change Proposal, RC_2009_11[62]. This is expected to have a net benefit to the market by minimising the risk associated with bringing new capacity into service.

The IMO also proposed a number of amendments to the Market Rules in Rule Change Proposal RC_2010_14[63] to address issues around the Certification of Reserve Capacity, including the Reserve Capacity Mechanism timeline. Improvements have been made to the timeline so that the IMO has more time for review of applications and Market Participants have more time to provide Reserve Capacity Security.

Key timeline changes are listed in Chapter 6 of the SOO. Market Participants applying for Certified Reserve Capacity for the 2013/14 year should make themselves aware of the changes. Further details can be found on the IMO website.

7.11 Reserve Capacity Mechanism Review

The IMO Board has commissioned a review of the Reserve Capacity Mechanism following concerns at the level of capacity oversupply in the market. The review seeks to identify potential changes that could improve the economic efficiency of the RCM while maintaining adequate investment signals and incentives.

This review is considering:

- the quantity and type of capacity procured;
- pricing of capacity;
- allocation of Reserve Capacity costs to Market Customers; and
- other elements such as the timing of the RCM, Expressions of Interest and Dispatch Instruction Payments.

The review of the Reserve Capacity refund mechanism, commenced as part of the Market Evolution Project, has recently been added to the scope of the RCM review (see Section 7.12 below).

The IMO anticipates that recommendations from the review will be presented to the MAC during the second half of 2011.

7.12 Market Evolution Project (MEP)

Following work done by industry representatives on the MAC in 2009 and the Verve Energy Review that identified a series of issues with the current WEM design, the Rules Development and Implementation Working Group (RDIWG) was convened in August 2010 to assess these

[62] www.imowa.com.au/RC_2009_11
[63] http://www.imowa.com.au/RC_2010_14

issues and identify solutions. The top priority issues included the areas of balancing, Reserve Capacity refunds, ancillary services and the operations of the STEM.

The RDIWG has been meeting for nine months and has ruled out recommending changes to the STEM at this stage. In addition, the work performed to date on Reserve Capacity refunds has now been referred to the broader RCM review (see Section 7.11). However, the RDIWG has progressed work on balancing and load following ancillary services. If decisions are confirmed by the RDIWG, MAC and then the IMO Board in the coming months in these areas, the aim will be to deliver:

1. A new balancing market in trials from December 2011 and fully operational from April 2012 that:
   (i) ensures the most economically efficient balancing options are used to provide balancing services – whether it be IPP generation, demand side management or Verve Energy generation; and
   (ii) ensures the State-owned generator (Verve Energy) can be increasingly treated like other Market Participants over time even though it remains as the default balancer.
2. A new load following ancillary service market fully operational from April 2012 that:
   (i) ensures the most economically efficient options are used to provide load following ancillary services – whether it be IPP generation, DSM or Verve generation; and
   (ii) ensures that Verve Energy can be increasingly treated like other Market Participants over time even though it remains as the default provider of ancillary services.
3. A more adaptable IT system with a longer life in place from 1 July 2012 that:
   (i) enables the MEP changes to be rolled out successfully, on time and on or under budget; and
   (ii) allows the market to continue to operate and evolve for another 3-5 years without further major IT investment and/or until more fundamental reforms are rolled out.

Further details can be found on the IMO's website[64].

[64] http://www.imowa.com.au/mep-overview

Appendix 1 Abbreviations

ABS – Australian Bureau of Statistics

APR – Transmission and Distribution Annual Planning Report (published by Western Power)

AQP – Applications and Queuing Policy

CCGT – Combined Cycle Gas Turbine

DBNGP – Dampier to Bunbury Natural Gas Pipeline

DSM – Demand Side Management

DTF – Western Australian Department of Treasury and Finance

EMC – Energy Market Commencement

EPA – Environmental Protection Authority

ERA – Economic Regulation Authority

GDP – Gross Domestic Product (for Australia)

GGP – Goldfields Gas Pipeline

GSP – Gross State Product (for Western Australia)

GWh – Gigawatt-hour

IMO – Independent Market Operator

IPP – Independent Power Producer

IRCR – Individual Reserve Capacity Requirement

KGP – Karratha Gas Plant

kV – kilovolt

LEED – Low Emissions Energy Development (Fund)

LT PASA – Long Term Projected Assessment of System Adequacy

MAC – Market Advisory Committee

MEP – Market Evolution Project

MCAP – Marginal Cost Administered Price

MRCPWG – Maximum Reserve Capacity Price Working Group

Mt – Megatonne

Mtpa – Million tonnes per annum

MW – Megawatt

NCS – Network Control Services

NEM – National Electricity Market

NFIT – New Facilities Investment Test

NIEIR – National Institute of Economic and Industry Research

OCGT – Open Cycle Gas Turbine

PJ – Petajoule

PoE – Probability of Exceedance

RCM – Reserve Capacity Mechanism

RDIWG – Rules Development Implementation Working Group

REC – Renewable Energy Certificate

REGWG – Renewable Energy Generation Working Group

RET – Renewable Energy Target

SKM-MMA – Sinclair Knight Merz MMA

SEI – Strategic Energy Initiative

SOO – Statement of Opportunity Report

STEM – Short Term Energy Market

SWIS – South West interconnected system

TJ – Terajoule

WEM – Wholesale Electricity Market

Appendix 2 Forecasts of Economic Growth- NEIR

Growth in Australian Gross Domestic Product (% Year on year growth)

Year	Expected	High	Low
2011/12	4.1	5.0	3.0
2012/13	3.3	4.1	2.1
2013/14	2.3	3.2	1.0
2014/15	2.5	3.8	1.4
2015/16	3.1	3.9	2.2
2016/17	3.1	4.2	2.2
2017/18	2.8	3.7	2.0
2018/19	2.7	3.6	1.8
2019/20	4.0	4.8	3.2
2020/21	3.5	4.2	2.9
2021/22	3.3	4.2	2.5
Average Growth %	**3.2**	**4.1**	**2.2**

Growth in Western Australian Gross State Product (% Year on year growth)

Year	Expected	High	Low
2011/12	5.0	5.7	3.6
2012/13	3.7	4.4	2.5
2013/14	2.0	3.0	1.1
2014/15	2.1	3.7	1.5
2015/16	3.6	4.4	2.2
2016/17	4.9	5.7	3.7
2017/18	4.1	4.8	3.3
2018/19	3.5	4.5	3.0
2019/20	5.2	5.7	3.6
2020/21	3.5	4.5	2.4
2021/22	3.6	4.6	2.9
Average Growth %	**3.7**	**4.6**	**2.7**

Appendix 3 Forecasts of Summer Maximum Demand

Summer Maximum Demand Forecasts with Expected Economic Growth (MW)

Year	10% PoE	50% PoE	90% PoE
2011/12	4,458	4,181	3,977
2012/13	4,635	4,340	4,122
2013/14	4,802	4,487	4,256
2014/15	5,219	4,889	4,646
2015/16	5,448	5,104	4,851
2016/17	5,625	5,264	4,998
2017/18	5,818	5,440	5,162
2018/19	5,978	5,584	5,294
2019/20	6,154	5,743	5,441
2020/21	6,316	5,889	5,574
2021/22	6,481	6,038	5,711
Average Growth %	**3.8**	**3.7**	**3.7**

Summer Maximum Demand Forecasts with High Economic Growth (MW)

Year	10% PoE	50% PoE	90% PoE
2011/12	4,506	4,228	4,023
2012/13	4,704	4,406	4,186
2013/14	4,891	4,573	4,339
2014/15	5,475	5,141	4,896
2015/16	5,697	5,348	5,091
2016/17	5,928	5,562	5,293
2017/18	6,215	5,832	5,549
2018/19	6,398	5,998	5,704
2019/20	6,643	6,226	5,919
2020/21	6,828	6,395	6,075
2021/22	7,022	6,571	6,239
Average Growth %	**4.5**	**4.5**	**4.5**

Summer Maximum Demand Forecasts with Low Economic Growth (MW)

Year	10% PoE	50% PoE	90% PoE
2011/12	4,386	4,112	3,910
2012/13	4,548	4,255	4,040
2013/14	4,707	4,396	4,167
2014/15	4,902	4,577	4,338
2015/16	5,089	4,751	4,501
2016/17	5,243	4,889	4,628
2017/18	5,392	5,022	4,749
2018/19	5,534	5,148	4,864
2019/20	5,707	5,306	5,010
2020/21	5,845	5,429	5,122
2021/22	5,993	5,560	5,242
Average Growth %	**3.2**	**3.1**	**3.0**

Appendix 4 Forecasts of Winter Maximum Demand

Winter Maximum Demand Forecasts with Expected Economic Growth (MW)

Year	10% PoE	50% PoE	90% PoE
2011	3,354	3,274	3,220
2012	3,410	3,328	3,273
2013	3,446	3,363	3,306
2014	3,830	3,744	3,685
2015	3,976	3,887	3,827
2016	4,059	3,968	3,906
2017	4,159	4,066	4,003
2018	4,227	4,132	4,067
2019	4,322	4,224	4,157
2020	4,391	4,292	4,224
2021	4,467	4,365	4,295
Average Growth %	**2.9**	**2.9**	**2.9**

Winter Maximum Demand Forecasts with High Economic Growth (MW)

Year	10% PoE	50% PoE	90% PoE
2011	3,422	3,336	3,286
2012	3,525	3,437	3,386
2013	3,611	3,521	3,467
2014	4,193	4,098	4,042
2015	4,362	4,264	4,206
2016	4,543	4,441	4,380
2017	4,785	4,680	4,616
2018	4,918	4,809	4,743
2019	5,129	5,016	4,948
2020	5,267	5,150	5,080
2021	5,420	5,299	5,226
Average Growth %	**4.7**	**4.7**	**4.7**

Winter Maximum Demand Forecasts with Low Economic Growth (MW)

Year	10% PoE	50% PoE	90% PoE
2011	3,267	3,187	3,138
2012	3,291	3,210	3,160
2013	3,306	3,224	3,173
2014	3,475	3,391	3,339
2015	3,547	3,462	3,409
2016	3,587	3,501	3,447
2017	3,622	3,533	3,479
2018	3,655	3,565	3,509
2019	3,724	3,633	3,576
2020	3,748	3,656	3,599
2021	3,786	3,692	3,634
Average Growth %	**1.5**	**1.5**	**1.5**

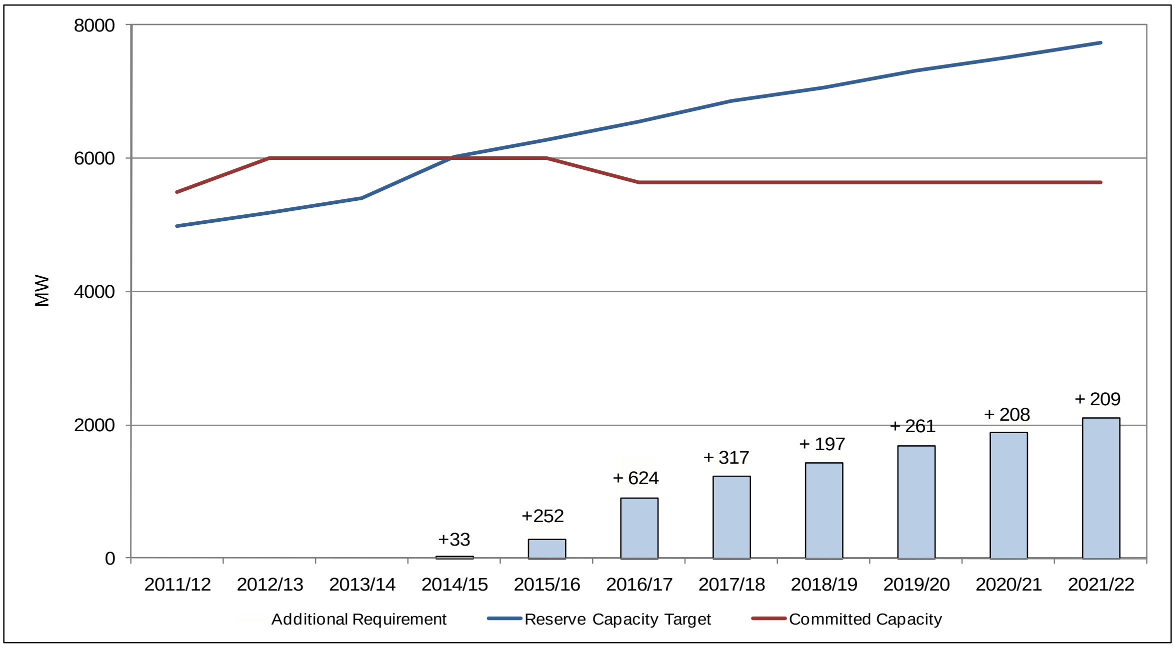
Appendix 5 Forecasts of Energy Sent-Out

Forecasts of Energy Sent-Out for the SWIS (GWh)

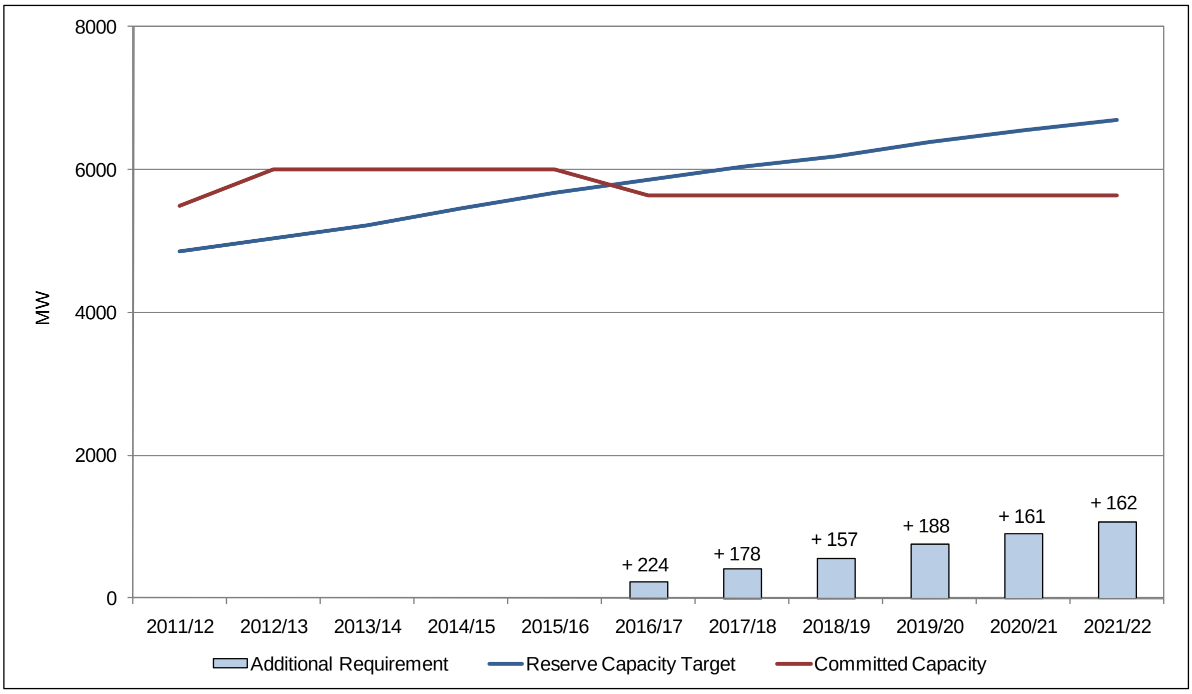
Year	Expected	High	Low
2011/12	19,377	19,757	18,713
2012/13	19,468	19,965	18,809
2013/14	20,040	20,705	18,967
2014/15	22,537	24,873	19,867
2015/16	23,174	25,153	20,453
2016/17	23,515	26,112	20,674
2017/18	24,193	27,708	20,934
2018/19	24,477	28,061	21,162
2019/20	25,043	29,387	21,745
2020/21	25,379	29,857	21,848
2021/22	25,802	30,586	22,144
Average Growth %	**2.9**	**4.5**	**1.7**

Appendix 6 Supply Demand Balance for High and Low Economic Forecasts

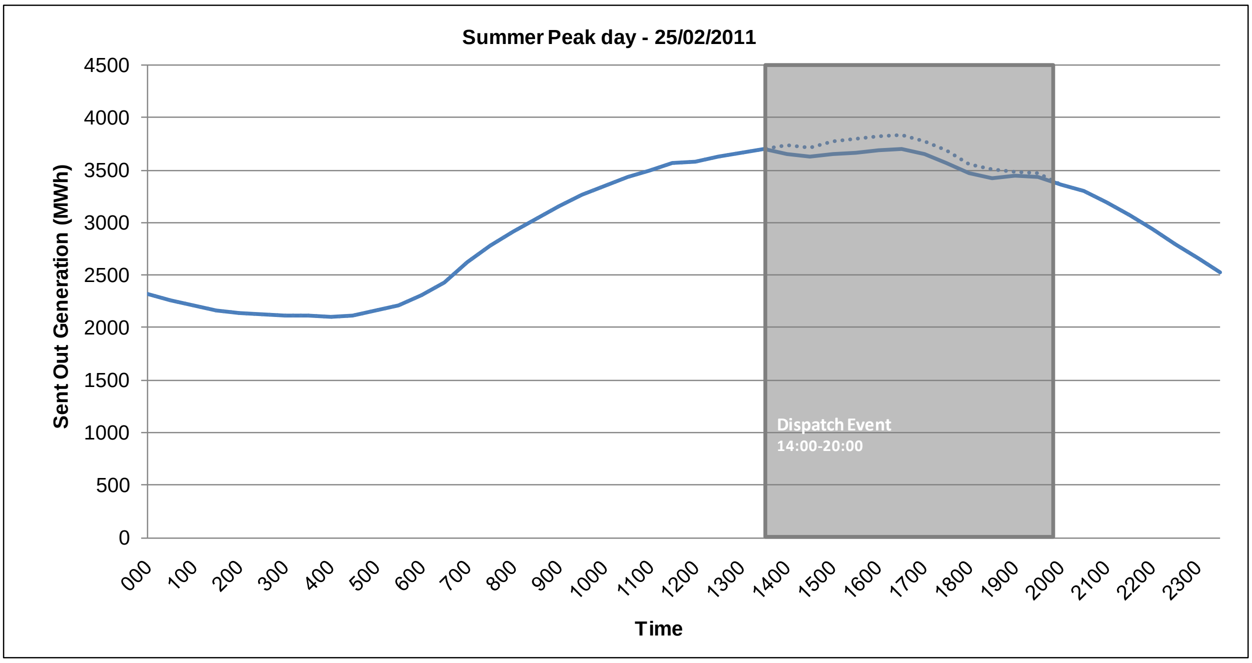
Required Generation and DSM Capacity in High Economic Growth Scenario

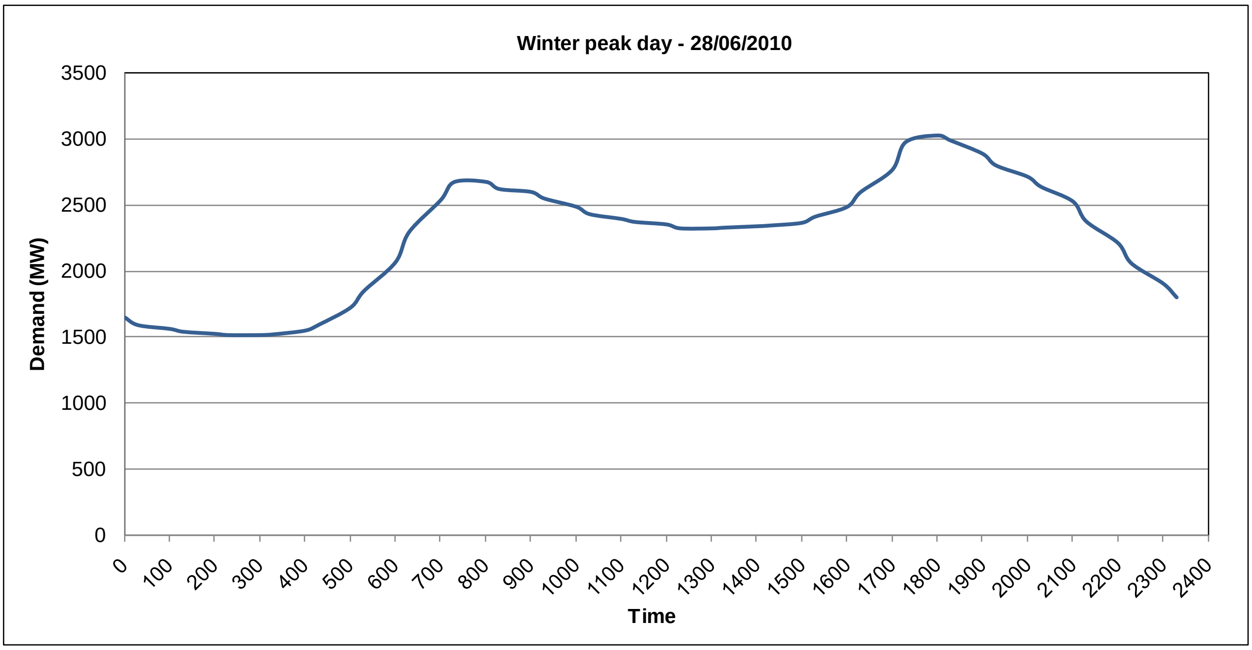


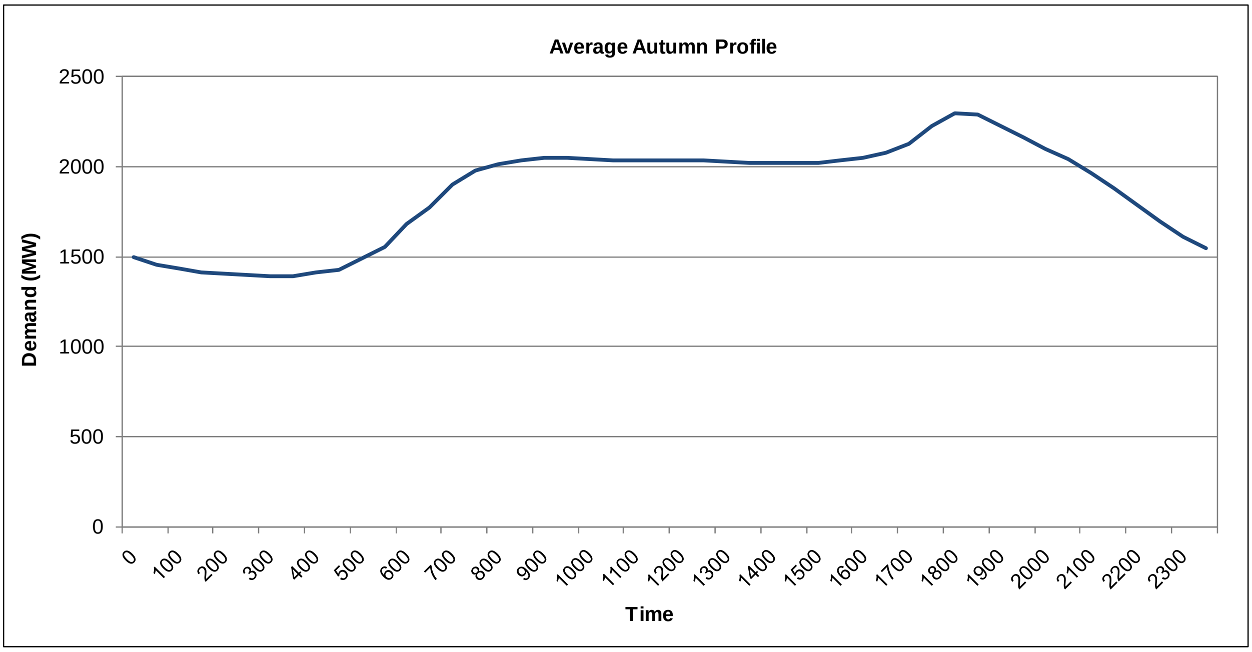
Required Generation and DSM Capacity in Low Economic Growth Scenario

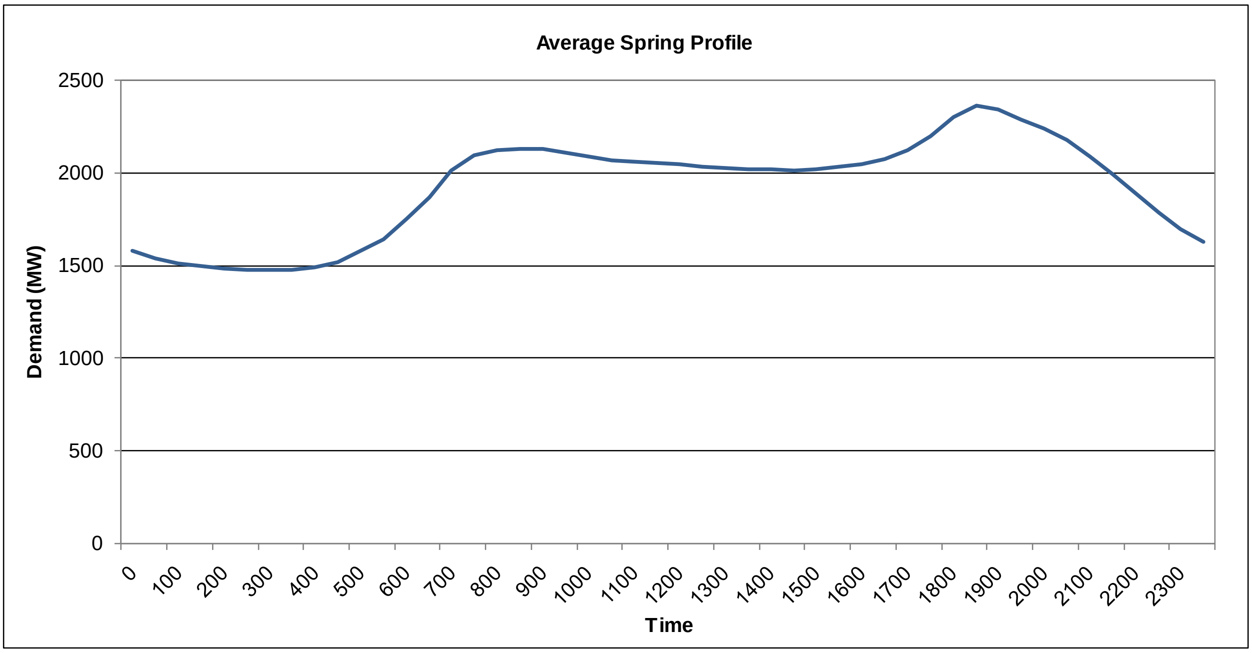


Appendix 7 Typical Daily Load Curves






Average Autumn Profile
2500
2000
1500
1000
500
0
Demand (MW)
0
100
200
300
400
500
600
700
800
900
1000
1100
1200
1300
1400
1500
1600
1700
1800
1900
2000
2100
2200
2300
Time


Average Spring Profile
2500
2000
1500
1000
500
0
Demand (MW)
0
100
200
300
400
500
600
700
800
900
1000
1100
1200
1300
1400
1500
1600
1700
1800
1900
2000
2100
2200
2300
Time

Appendix 8 Determination of Availability Curve

The Availability Curve ensures that there is sufficient capacity at all times to satisfy both elements of the Planning Criterion (10% PoE peak demand + Margin and 0.002% Unserved Energy), as well as ensuring that sufficient capacity is available to satisfy the criteria for evaluating Outage Plans.

Assuming that the Reserve Capacity Target is just met, the Availability Curve indicates the minimum amount of capacity required to be provided by generation capacity to ensure that the energy requirements of users are satisfied . The remainder of the Reserve Capacity Target can be met by further generation capacity or by DSM.

The determination of the Availability Curve follows the following steps, which are outlined in clause 4.5.12 of the Market Rules.

1. A load curve is developed based on historical load profiles and scaled up to match the 50% PoE peak demand[65] and expected energy consumption forecasts for the relevant year. This load shape aligns with both the peak demand and energy elements of the Planning Criterion. The capacity required for more than 24 hours per year, 48 hours per year, 72 hours per year and 96 hours per year is determined from this load curve (clause 4.5.12(a)).

2. A generation availability curve is developed by assuming that the level of generation matches the Reserve Capacity Requirement for the relevant year, then allowing for typical levels of planned and forced outages. For existing facilities, future outage plans (based on information provided by Market Participants under clause 4.5.4) are included in this consideration.

3. Generation capacity is then incrementally replaced by DSM capacity, while maintaining the total quantity of capacity at the Reserve Capacity Requirement until either the Planning Criterion or the criteria for evaluating Outage Plans is breached. If the Reserve Capacity Target has been set based on the peak demand criterion (10% PoE peak demand + Margin), then the minimum capacity required to be provided by generation ("Minimum Generation", clause 4.5.12(b)) will the quantity of generation at which either:

    a. The total unserved energy exceeds 0.002% of annual energy consumption, thus breaching the Planning Criterion; or

    b. The spare generation capacity drops below 539 MW (the quantity required to provide Ancillary Services and satisfy the Ready Reserve Standard), thus breaching the criteria for evaluating Outage Plans.

[65] The use of the 50% PoE peak demand forecast in developing the load curve results in virtually the same outcome as would be achieved if the 10% PoE peak demand forecast was used. An indicative load profile for a year with a 10% PoE peak demand (2003/04), the 50% PoE level was exceeded for less than 24 hours, suggesting that the incremental load could be met with DSM. In addition, the analysis ensures that the spare generating capacity remains at least 539 MW above the monthly peak demand, which is approximately equivalent to the second deviation load forecast described in clause 3.18.11 of the Market Rules.

The Availability Curve (the capacity associated with each Availability Class in Table 4) is then calculated from the load curve and the Minimum Generation according to the method outlined in clause 4.5.12(c) of the Market Rules.

- Availability Class 4 is defined as the Reserve Capacity Requirement less the greater of the capacity required for less than 48 hours and the Minimum Generation;
- Availability Class 3 is defined as the Reserve Capacity Requirement less the greater of the capacity required for less than 72 hours and the Minimum Generation, less the capacity associated with Availability Class 4;
- Availability Class 2 is defined as the Reserve Capacity Requirement less the greater of the capacity required for less than 96 hours and the Minimum Generation, less the capacity associated with Availability Classes 3 and 4;
- Availability Class 1 is defined as the Reserve Capacity Requirement less the capacity associated with Availability Classes 2, 3 and 4.

The IMO notes that the current methodology for determination of the Availability Curve outlined in the Market Rules does not consider all of the operational limitations regarding the scheduling of DSM and thus may overestimate the capacity that can be provided by DSM.

- In determining the Minimum Generation in clause 4.5.12(b), the Market Rules require that DSM is considered to be applied “so as to minimise the peak demand”. In practice, this would require that the top 96 hours of peak demand could be predicted in advance so as to schedule the DSM capacity in these periods, which would be virtually impossible.
- This consideration also fails to account for specific limits on the availability of DSM, such as the maximum number of hours of curtailment per day that is specified by providers of DSM capacity, or the potential unavailability of DSM on the third consecutive day as allowed under clause 4.12.8 of the Market Rules.
- The determination of the capacity requirements for each Availability Class in clause 4.5.12(c) of the Market Rules implicitly assumes that the capacity in each Availability Class is available for the maximum number of hours applicable to that class. For example, Availability Class 4 includes the capacity required for up to 48 hours, though in practice Availability Class 4 can be filled with Facilities that are only available for 24 hours.

The IMO will review the methodology further prior to the publication of the 2012 Statement of Opportunities and will propose changes to the Market Rules as required to address the limitations in the methodology.

Appendix 9 Facility Capacities

Registered Generation Facilities - Existing and Committed

Participant Name	Facility Name	Capacity Credits (2012/13)
Alcoa of Australia	ALCOA_WGP	24
Alinta Sales	ALINTA_PNJ_U1	132.823
Alinta Sales	ALINTA_PNJ_U2	132.355
Alinta Sales	ALINTA_WGP_GT	176
Alinta Sales	ALINTA_WGP_U2	176
Alinta Sales	ALINTA_WWF	38.73
Collgar Wind Farm	INVESTEC_COLLGAR_WF1	90
EDWF Manager	EDWFMAN_WF1	29.335
Goldfields Power	PRK_AG	61.4
Griffin Power	BW1_BLUEWATERS_G2	215.9
Griffin Power 2	BW2_BLUEWATERS_G1	204
Griffin Power 2	BW2_BLUEWATERS_UPG	11.9
Landfill Gas & Power	CANNING_MELVILLE	1.005
Landfill Gas & Power	KALAMUNDA_SG	1.3
Landfill Gas & Power	RED_HILL	2.791
Landfill Gas & Power	TAMALA_PARK	3.575
Mt.Barker Power Company	SKYFRM_MTBARKER_WF1	0.935
Namarkkon	NAMKKN_MERR_SG1	70
NewGen Power Kwinana	NEWGEN_KWINANA_CCG1	320
NewGen Neerabup Partnership	NEWGEN_NEERABUP_GT1	330.6
Perth Energy	ATLAS	0.883
Perth Energy	GOSNELLS	0.571
Perth Energy	ROCKINGHAM	1.641
Perth Energy	SOUTH_CARDUP	2.878
Southern Cross Energy	STHRNCRS_EG	12
Tesla Corporation	TESLA_GERALDTON_G1	9.9
Tesla Corporation	TESLA_KEMERTON_G1	9.9
Tesla Corporation	TESLA_NORTHAM_G1	9.9
Tesla Corporation	TESLA_PICTON_G1	9.9
Verve Energy	ALBANY_WF1	6.847
Verve Energy	BREMER_BAY_WF1	0.163
Verve Energy	COCKBURN_CCG1	231.8

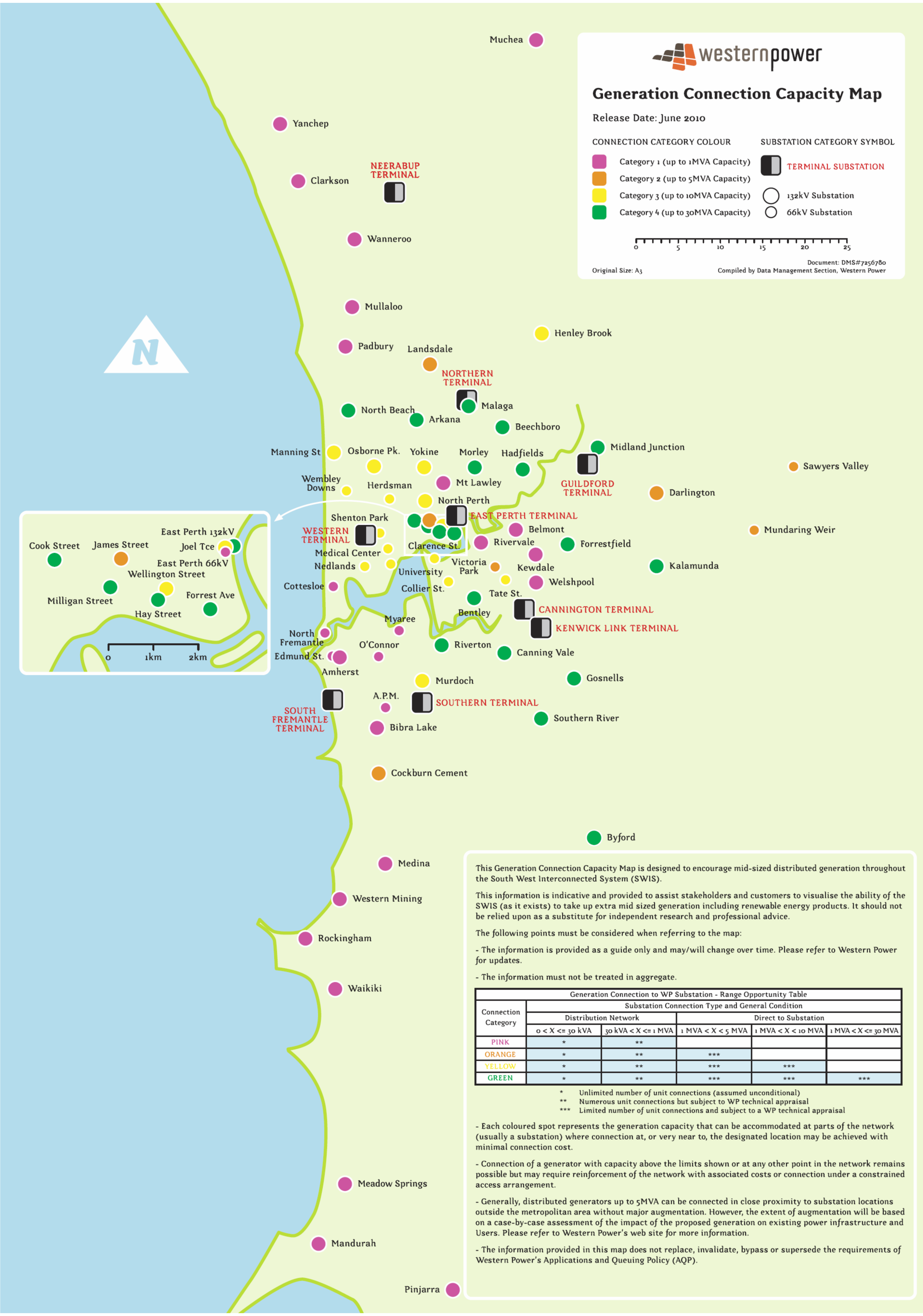
Participant Name	Facility Name	Capacity Credits (2012/13)
Verve Energy	COLLIE_G1	318
Verve Energy	GERALDTON_GT1	15.6
Verve Energy	GRASMERE_WF1	4.966
Verve Energy	KALBARRI_WF1	0.578
Verve Energy	KEMERTON_GT11	143
Verve Energy	KEMERTON_GT12	141.7
Verve Energy	KWINANA_G5	177.5
Verve Energy	KWINANA_G6	184
Verve Energy	KWINANA_GT1	15.29
Verve Energy	KWINANA_GT2	92.156
Verve Energy	KWINANA_GT3	92.156
Verve Energy	MUJA_G1	55
Verve Energy	MUJA_G2	55
Verve Energy	MUJA_G3	55
Verve Energy	MUJA_G4	55
Verve Energy	MUJA_G5	185
Verve Energy	MUJA_G5_UPG	4
Verve Energy	MUJA_G6	185
Verve Energy	MUJA_G7	211
Verve Energy	MUJA_G8	211
Verve Energy	MUNGARRA_GT1	33
Verve Energy	MUNGARRA_GT2	32.9
Verve Energy	MUNGARRA_GT3	31.629
Verve Energy	PINJAR_GT1	32.15
Verve Energy	PINJAR_GT10	107
Verve Energy	PINJAR_GT11	115
Verve Energy	PINJAR_GT2	31.52
Verve Energy	PINJAR_GT3	37
Verve Energy	PINJAR_GT4	37
Verve Energy	PINJAR_GT5	37
Verve Energy	PINJAR_GT7	37
Verve Energy	PINJAR_GT9	107
Verve Energy	PPP_KCP_EG1	76.9
Verve Energy	PPP_KCP_UPG1	1.75
Verve Energy	PPP_KCP_UPG2	1.75
Verve Energy	SWCJV_WORSLEY_COGEN_COG1	106
Verve Energy	TIWEST_COG1	33

Participant Name	Facility Name	Capacity Credits (2012/13)
Verve Energy	WEST_KALGOORLIE_GT2	34.25
Verve Energy	WEST_KALGOORLIE_GT3	19
Western Energy	PERTHENERGY_KWINANA_GT1	85
Western Energy	PERTHENERGY_KWINANA_GT1_UPG1	20
Western Energy	PERTHENERGY_KWINANA_GT1_UPG2	3
Waste Gas Resources	HENDERSON_RENEWABLE_IG1	2.3

Registered DSM Facilities - Existing and Committed

Participant Name	Facility Name	Capacity Credits (2012/13)	Availability (hr / year)
Alinta Sales	ALINTA_DSM_1	17	24
Amanda Australia	AMAUST_DSM_001	9.9	24
Barrick (Kanowna)	KANOWNA_CL1	10	24
DMT energy	DMTENERGY_CL1	17	24
DMT energy	DMTENERGY_CL2	33	24
EnerNOC Australia	ENERNOC_CL1	50	24
Energy Response	ERESPONS_CL1	23	24
Energy Response	ERESPONS_CL2	50	24
Energy Response	ERESPONS_CL4	67.086	24
Griffin Power	DSM_BODDINGTON_CL1	20	48
Premier Power Sales	PREMPWR_DSM_CL1	10	24
Premier Power Sales	PREMPWR_DSM_CL3	20	48
Premier Power Sales	PREMPWR_DSM_CL5	4	24
Premier Power Sales	PREMPWR_DSM_CL6	3	24
Premier Power Sales	PREMPWR_DSM_CL8	2	24
Premier Power Sales	PREMPWR_DSM_CL9	2	24
Synergy	SYNERGY_DSM_PROGRAM	10	32
Synergy	SYNERGY_DSM_PROGRAM_2	5	32
Synergy	SYNERGY_DSM_PROGRAM_3	5	32
Synergy	SYNERGY_PDS142_CL41	40	48
Water Corporation	WATERCORP_CL1	14	24
Water Corporation	WATERCORP_CL1_UPG	1	24
Water Corporation	WATERCORP_CL1_UPG2	4	24
Water Corporation	WATERCORP_CL2	17.5	24
Water Corporation	WATERCORP_CL3	6	24
Water Corporation	WATERCORP_CL3_UPG	14	24

Appendix 10 Generation Connection Capacity Map



Generation Connection Capacity Map

Release Date: June 2010

CONNECTION CATEGORY COLOUR

- Category 1 (up to 1MVA Capacity)
- Category 2 (up to 5MVA Capacity)
- Category 3 (up to 10MVA Capacity)
- Category 4 (up to 30MVA Capacity)

SUBSTATION CATEGORY SYMBOL

- TERMINAL SUBSTATION
- 132kV Substation
- 66kV Substation

0 5 10 15 20 25

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Original Size: A3
Compiled by Data Management Section, Western Power

This Generation Connection Capacity Map is designed to encourage mid-sized distributed generation throughout the South West Interconnected System (SWIS).

This information is indicative and provided to assist stakeholders and customers to visualise the ability of the SWIS (as it exists) to take up extra mid sized generation including renewable energy products. It should not be relied upon as a substitute for independent research and professional advice.

The following points must be considered when referring to the map:

- The information is provided as a guide only and may/will change over time. Please refer to Western Power for updates.

- The information must not be treated in aggregate.

Generation Connection to WP Substation - Range Opportunity Table

Connection Category	Substation Connection Type and General Condition				
	Distribution Network		Direct to Substation		
	0 < X <= 30 kVA	30 kVA < X <= 1 MVA	1 MVA < X < 5 MVA	1 MVA < X < 10 MVA	1 MVA < X <= 30 MVA
PINK	*	**			
ORANGE	*	**	***		
YELLOW	*	**	***	***	
GREEN	*	**	***	***	***

* Unlimited number of unit connections (assumed unconditional)
** Numerous unit connections but subject to WP technical appraisal
*** Limited number of unit connections and subject to a WP technical appraisal

- Each coloured spot represents the generation capacity that can be accommodated at parts of the network (usually a substation) where connection at, or very near to, the designated location may be achieved with minimal connection cost.

- Connection of a generator with capacity above the limits shown or at any other point in the network remains possible but may require reinforcement of the network with associated costs or connection under a constrained access arrangement.

- Generally, distributed generators up to 5MVA can be connected in close proximity to substation locations outside the metropolitan area without major augmentation. However, the extent of augmentation will be based on a case-by-case assessment of the impact of the proposed generation on existing power infrastructure and Users. Please refer to Western Power's web site for more information.

- The information provided in this map does not replace, invalidate, bypass or supersede the requirements of Western Power's Applications and Queuing Policy (AQP).