Independent Market Operator

Statement of Opportunities

June 2012

Disclaimer

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The purpose of this publication is to provide technical and market data and information regarding opportunities in the Wholesale Electricity Market in Western Australia.

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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 process within the Reserve Capacity Mechanism (RCM) - the mechanism through which the WEM secures sufficient 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 Demand Side Management (DSM) being committed over the last seven years. This increased investment has resulted in an increased number of Market Participants and greater competition in the market.

The SOO focuses on opportunities for investment in generation and DSM capacity over the medium term. The 2012 SOO places emphasis on the 2014/15 Capacity Year, setting the capacity requirement for the year commencing 1 October 2014. Information is also provided on forecast maximum demand and electricity consumption within the South West interconnected system (SWIS) through to October 2023.

In addition, the SOO provides stakeholders with:

- a detailed commentary on the current status of the transmission network;
- a discussion on the availability of fuel for generation (see Section 7.3); and
- information on key areas of reform that are planned or underway in the WEM (see Chapter 7).

Key Results for 2014/15

- The Reserve Capacity Target for 2014/15 is set at 5,308 MW. This is based on the one-in-ten year peak demand forecast with additional allowances for unplanned facility outages (8.2% of the peak demand forecast), provision of frequency control services and Intermittent Loads.
- Forecast average annual growth through to 2022/23 is 3.0% for peak demand and 2.1% for energy. These rates are materially lower than the projected growth rates from the 2011 SOO of 3.8% for peak demand and 2.9% for energy.
- The IMO anticipates that 6,057 MW of generation and DSM capacity, either existing or committed with Capacity Credits for 2013/14, will continue in service through to 2014/15.
- The existing in-service or committed facilities represent a surplus of 749 MW of capacity above the Reserve Capacity Target for 2014/15, prior to the introduction of any new capacity for that year.

Table A shows the Reserve Capacity Target for each year of the Long Term Projected Assessment of Supply Adequacy (PASA) Study Horizon, as determined from the peak demand requirement of the Planning Criterion.

Table A – 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
2012/13	4460	366	90	15	4931
2013/14	4659	382	90	15	5146
2014/15	4804	394	95	15	5308
2015/16	4950	406	100	16	5472
2016/17	5135	421	105	16	5677
2017/18	5290	434	110	16	5850
2018/19	5419	444	115	16	5994
2019/20	5563	456	120	17	6156
2020/21	5711	468	125	17	6321
2021/22	5859	480	130	17	6486
2022/23	5990	491	135	17	6633

Changes to demand forecasts

The demand forecasts this year represent a significant reduction from those presented in the 2011 Statement of Opportunities, following a similar reduction last year. Various factors have contributed to these reductions:

- The IMO has significantly reduced its allowance for new major block loads in the expected growth forecast. As described in Section 4.3, the IMO considers the likely timing and size of these loads using the information available at the time of publication. Since 2008, the prediction of new block loads has been dominated by four major mining projects. One of these loads has now commenced operation, though its consumption is lower than originally projected. While a second mining project is under construction, the remaining projects have yet to be formally committed. The IMO has shifted these iron ore developments into the high growth forecasts this year due to the lack of demonstrable progress. In addition, the IMO has reduced the allowance for these new loads consistent with the observed consumption of other operational mining projects.
- The penetration of air conditioning systems in the SWIS increased dramatically in the first decade of this century. The average annual increase in summer temperature sensitive load from 2000 to 2010 was more than four times the annual increase during the early 1990's. However, recent market data suggests that the growth trend in temperature sensitive load has materially changed. This required a significant recalibration of the forecasting models last year to increase the assumed levels of air conditioner replacement and lower the assumed utilisation rate.
- Recent consumption data has demonstrated a material dislocation between economic growth in Western Australia and the growth in underlying electricity demand. The projected total sent out electricity for the 2011/12 financial year is lower than the 2010/11 total, the first such occurrence since the start of the market.

  After normalising for the effects of temperature, electricity demand for the SWIS has remained relatively flat since the 2008/09 financial year as shown in Figure A. This flat growth trend has been masked by above-average temperatures during the last three summers, but has been identified by the National Institute of Economic and Industry Research (NIEIR) as part of the causal analysis of changes in the forecasts.

A number of factors are likely to have contributed to this flat growth in demand:

- The penetration of small-scale solar photovoltaic (PV) generation has increased markedly in the last few years, supported by Government subsidies, including feed-in tariff schemes, and reducing system costs. Small-scale solar PV generation is not separately measurable by the IMO and is observed as reduced consumption. Forecasts developed in previous years have not specifically considered the impact of small-scale PV, largely due to the lack of available information from Government agencies and State-owned utilities. This year's forecasts consider the impact of small-scale solar PV generation for the first time, including a reduction in the peak demand forecast in 2014/15 of 84 MW.
- The restricted availability and increased cost of finance since the onset of the Global Financial Crisis (GFC) has hampered business investment since that time, though this has been masked by the higher values of a small number of projects, particularly LNG and iron ore developments.
- The increases in regulated electricity tariffs, which commenced from April 2009, have seen prices for residential customers increase by 57% within three years, with similar increases in the regulated tariffs that apply to small commercial and industrial customers.
- Energy efficient appliances, energy efficiency programs and public awareness campaigns may be driving behavioural change amongst consumers.

Figure A – Sent Out Energy, Adjusted for New Major Loads and Temperature

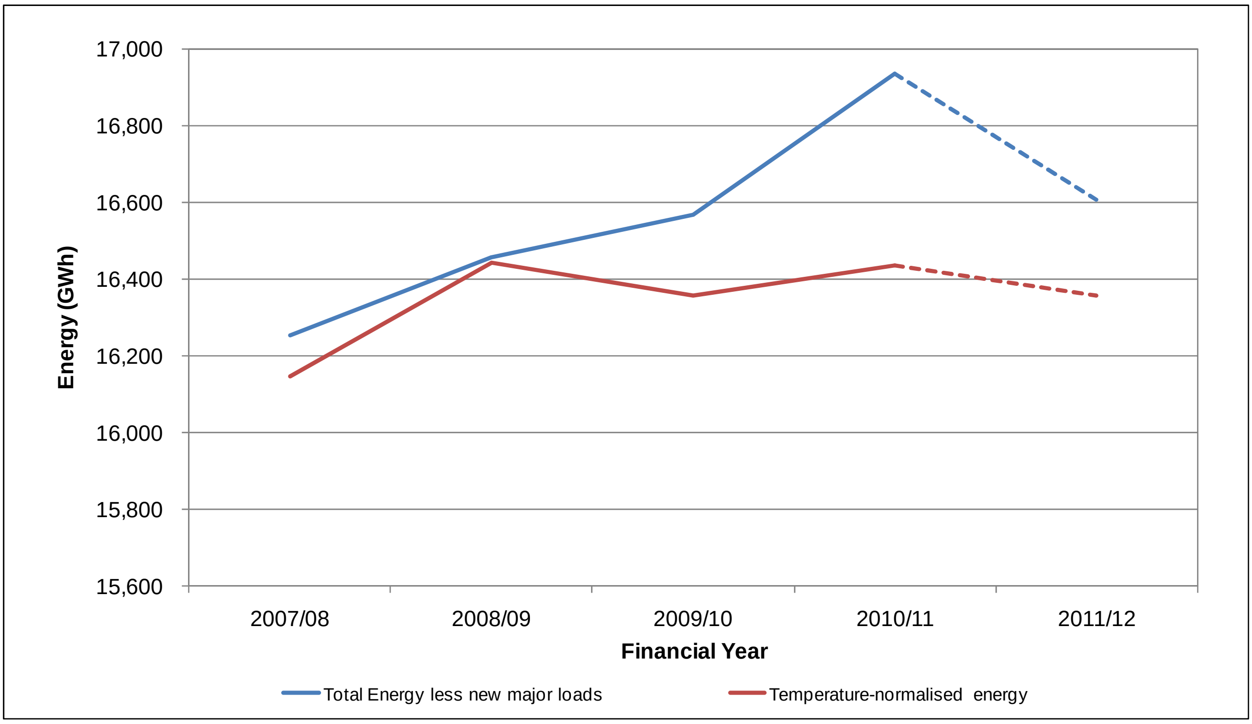


Table B provides causal analysis of the flat growth between the 2013/14 and 2014/15 Reserve Capacity Requirements. The low year-on-year change in the underlying demand forecast reflects the recent flat growth in energy sales. While there has been a reduction in the allowances for block loads across the ten-year forecasting horizon, the impact of the revised block load assumptions shown below is upward. The reduction in block load forecasts described above affects the forecasts from 2014/15 onwards.

Table B – Comparison of 2013/14 and 2014/15 Reserve Capacity Requirements

2013/14 Reserve Capacity Requirement	**5,312 MW**
Changes to 2013/14 block load assumptions (plus 8.2%)	+ 9 MW
Additional block load assumed for 2014/15 (plus 8.2%)	+ 16 MW
Inclusion of 2013/14 solar PV (plus 8.2%)	- 77 MW
Additional solar PV for 2014/15 (plus 8.2%)	- 14 MW
Change to Load Following requirement	- 5 MW
Year-on-year change in underlying demand forecast	+ 67 MW
2014/15 Reserve Capacity Requirement	**5,308 MW**

Expressions of Interest for New Capacity

In May 2012, the IMO completed its annual Expression of Interest process to identify new sources of generation and DSM capacity for 2014/15.

17 Expressions of Interest were received, covering a total potential Reserve Capacity of 213.7 MW. The amounts of each type of capacity are shown in Table C.

Table C – Summary of 2012 Expressions of Interest

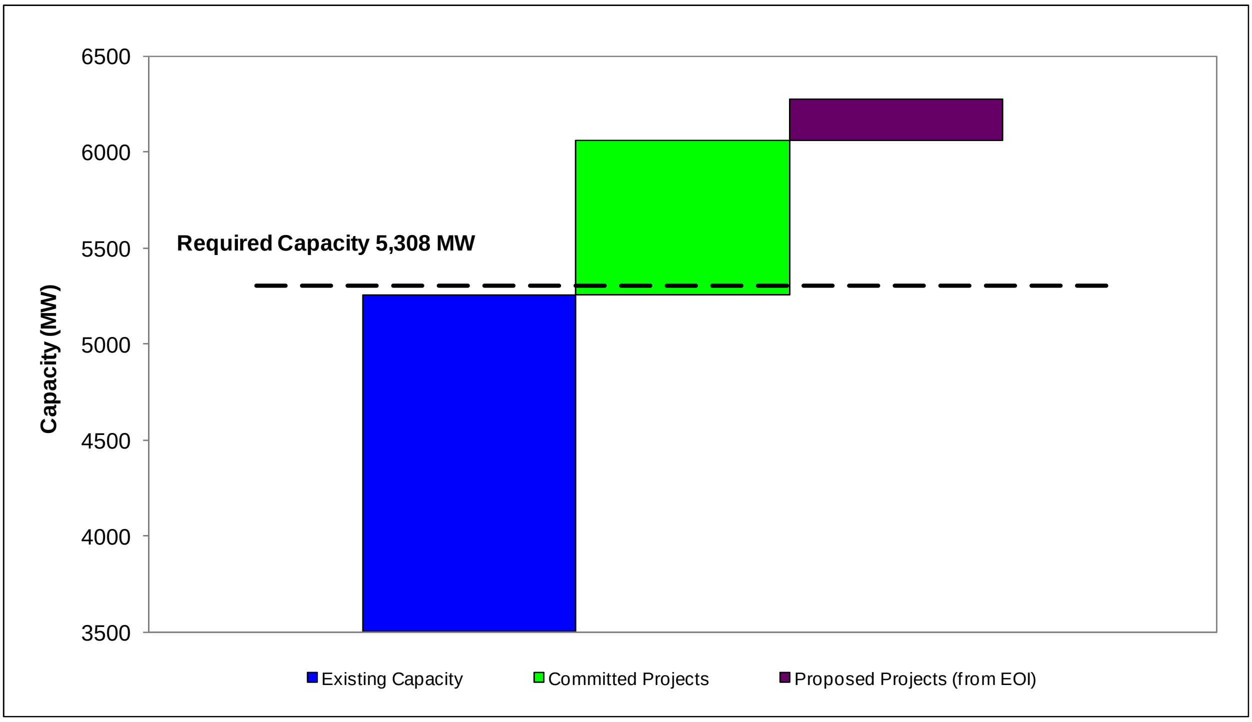
Type of Capacity in the EOI process	Aggregate Potential Reserve Capacity (MW)
Thermal	114.2
Renewable	80.3
DSM	19.2
Total	**213.7**

While it provides an indication of potential future capacity, the submission of an Expression of Interest does not necessarily translate into certified capacity. In 2011, Expressions of Interest were received for 337 MW of new capacity but only 42 MW of this capacity was assigned Capacity Credits for the 2013/14 Capacity Year.

The IMO estimates that approximately 67 MW of new capacity from the Expression of Interest process could potentially be available to meet demand in the 2014/15 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 2014/15 Capacity Year.

Figure B illustrates the expected status of capacity in the SWIS in the 2014/15 Capacity Year.

Figure B – Forecast Reserve Capacity Status for 2014/15



Supply-Demand Balance

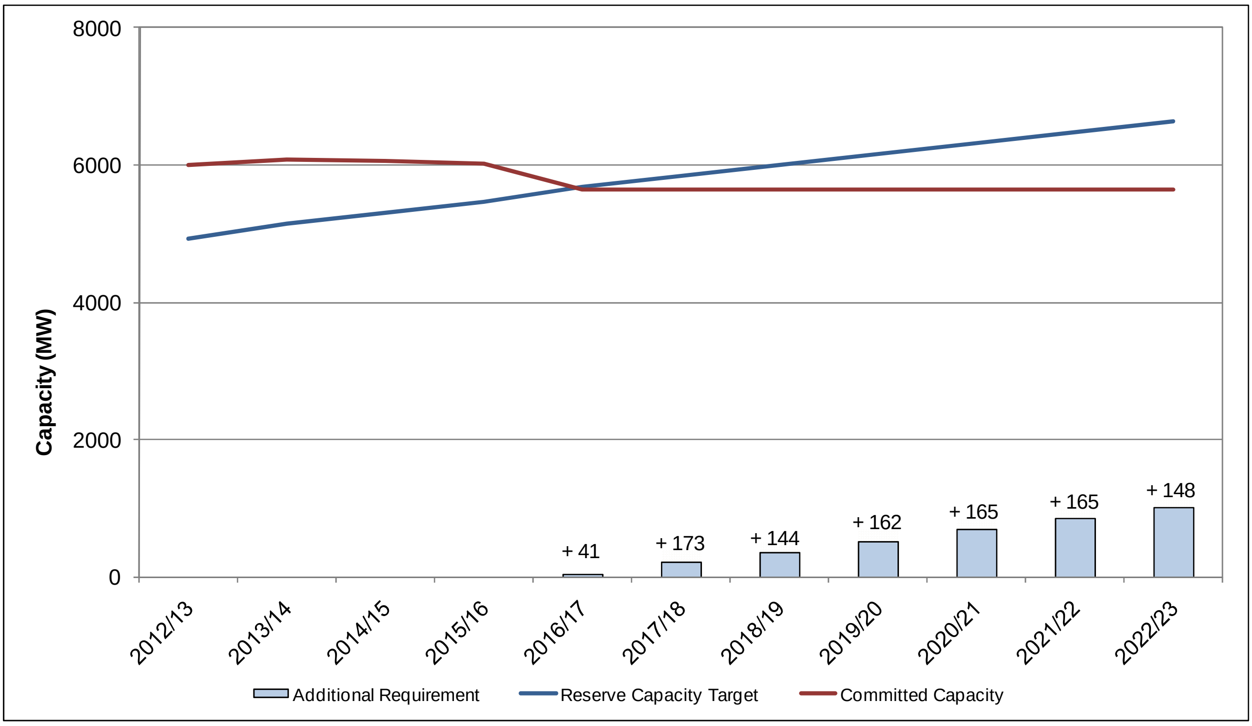
Figure C shows the supply-demand balance over the period 2012/13 through to 2022/23.

Key points to note from Figure C are:

- Sufficient Capacity Credits have been procured in previous years to meet the Reserve Capacity Requirement during 2012/13 and 2013/14.
- The level of committed capacity has been reduced over three years from 2014/15 to 2016/17 by the IMO's estimate of the likely reduction in Capacity Credits for Intermittent Generators following the implementation of Rule Change RC_2010_25.
- The IMO has anticipated the decommissioning of Verve Energy's Kwinana Stage C facilities for the 2016/17 Capacity Year, although the timing of this retirement is subject to a commercial decision by Verve Energy.
- Existing and committed capacity is expected to be sufficient to satisfy the Reserve Capacity Requirement through to 2015/16.

- By 2022/23 the total capacity requirement is forecast to be 6,633 MW. After allowing for the anticipated retirement of Kwinana Stage C, additional capacity of 998 MW is forecast to be required to service demand growth.

Figure C – Supply-Demand Balance for the Period 2012/13 to 2022/23



Importance of New Transmission Works

As in previous years, the IMO has considered the timing of the Mid West Energy Project (MWEP) (Southern Section) to be developed by Western Power.

As discussed in Section 4.4, the IMO has not included any additional block load allowance in the expected growth forecasts immediately following the completion of the MWEP (Southern Section).

However, the timing of these works can impact on the connection and certification of proposed new generators. An essential requirement for certification is that a new generator will be in service prior to 1 October 2014. Certainty of network access is a prerequisite for certification under the Reserve Capacity Mechanism.

All new generators must provide the IMO with sufficient evidence for it to satisfy itself that this can be achieved, including a transmission access proposal from Western Power with details of network studies that have been completed.

Western Power has provided the IMO with an update on the MWEP as at 13 June 2012. Full details are included in Section 7.2 of this SOO.

Given the information provided by Western Power, including the risks to the project schedule, and the expectation that additional works would be required to connect a generator that is reliant on the MWEP, the IMO does not consider it likely that such a generator could be granted firm access by 1 October 2014.

Consequently, the IMO will be unable to assign Certified Reserve Capacity for the 2014/15 Capacity Year to any proposed new generators which rely on the new transmission works.

Generation projects reliant on the MWEP (Southern Section) would be able to apply for certification in future years once firm network access can be secured.

Reform in the Wholesale Electricity Market

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

- the implementation of the new Balancing and Load Following Ancillary Services markets as part of the Market Evolution Project (MEP);
- the review of the RCM, being conducted by the IMO with the assistance of the Reserve Capacity Mechanism Working Group (RCMWG); and
- the five yearly reviews of the Planning Criterion and the IMO's forecasting processes, being conducted by the IMO during 2012.

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

Other reviews are also underway that may impact the structure or operation of the WEM, including:

- the review of the Electricity Networks Access Code, being conducted by the Public Utilities Office; and
- 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.

Next Steps

Parties offering a generation or a DSM facility as Reserve Capacity must register with the IMO as a Rule Participant and must register their facilities for the purposes of Reserve Capacity. Rule 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 2014/15 Capacity Year must be provided to the IMO by 5:00 PM WST on Friday, 29 June 2012.

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.

Table of Contents

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

Economic activity in Western Australia (WA) continues to be robust, maintaining the recovery since the onset of the global economic downturn, supporting long-term growth in electricity demand. However, recent years have seen the emergence of new government policy and consumption trends that are materially modifying consumption patterns, such as distributed solar PV generation, energy efficient appliances, energy efficiency programs and increasing electricity prices.

A material capacity cushion has developed within the South West Interconnected System (SWIS) over the last three Reserve Capacity Cycles. However, the 2011 Reserve Capacity Cycle saw a sharp reduction in future demand forecasts and the lowest entry of new capacity since the commencement of the WEM.

The recently completed Expression of Interest process indicates interest in further capacity development. However, while the Expression of Interest process provides an indication of potential future capacity, the submission of an Expression of Interest does not necessarily translate into certified capacity. In 2011, Expressions of Interest were received for 337 MW of new capacity but only 42 MW of this capacity was assigned Capacity Credits for the 2013/14 Capacity Year.

Government policy measures are stimulating investment in renewable projects submitting into the Expressions of Interest process. In Western Australia feed-in tariffs have encouraged a substantial increase in residential solar PV generation, though this program has now been suspended for new connections.

The rate of growth of Demand Side Management (DSM) capacity is expected to slow significantly following substantial growth from 260 MW in 2011/12 to 500 MW in 2013/14.

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 and to set the Reserve Capacity Requirement for the 2014/15 Capacity Year.

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 DSM capacity and facilitates the introduction of this capacity onto the SWIS.

The 2012 SOO contains a detailed profile of the SWIS, including:

- historical load data, a current load duration curve and typical load profiles;
- an 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 2011 SOO, incorporating the 2012 Summary of Expressions of Interest (published in May 2012); and

- energy consumption and peak demand forecasts for the Long Term PASA Study Horizon, which extends to 2022/23.

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).

To ensure that sufficient capacity is secured for extreme weather events, the IMO is required to set the Reserve Capacity Requirement based on the 10% PoE forecast.

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 2011/12 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 3,800 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 early February and mid-March. The daily peak demand is higher on business days than on weekends and public holidays, and is also higher during school term than during school 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.

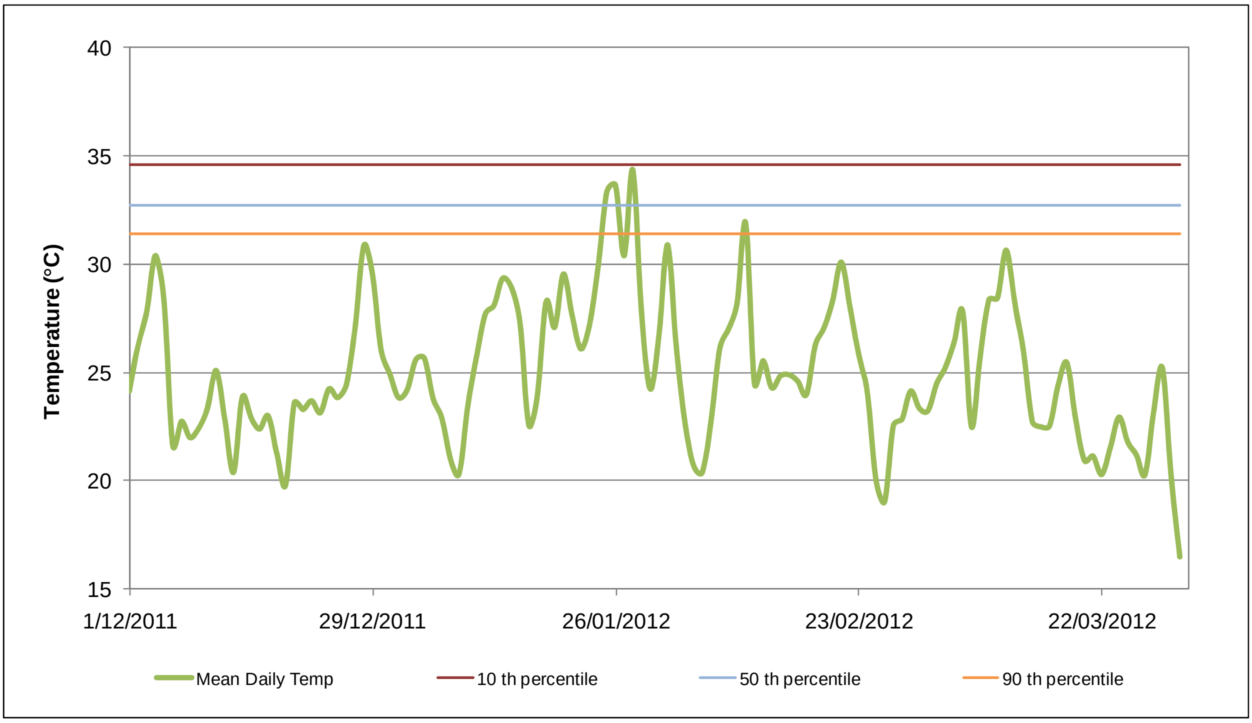
During the 2011/12 hot season, Perth experienced temperatures more than 1°C above the 20-year average.

However, while the daily maximum temperature reached 40°C on six occasions during the 2011/12 hot season, only three of these occasions were on business days (one in each of January, February and March). In addition, while there were three occurrences of consecutive days above 37°C, none fit the profile of a "typical" peak demand event:

- Two consecutive days on 28-29 December fell between Christmas and New Year;
- Five consecutive days on 24-28 January fell in the interrupted Australia Day week, prior to the start of the school year; and
- Four consecutive days on 9-12 March fell across a weekend and followed cooler overnight temperatures (average minimum temperature of 17.8°C).

Figure 1 shows the daily average temperature for the period from December 2011 to March 2012.

Figure 1 – Perth Daily Average Temperatures December 2011 to March 2012



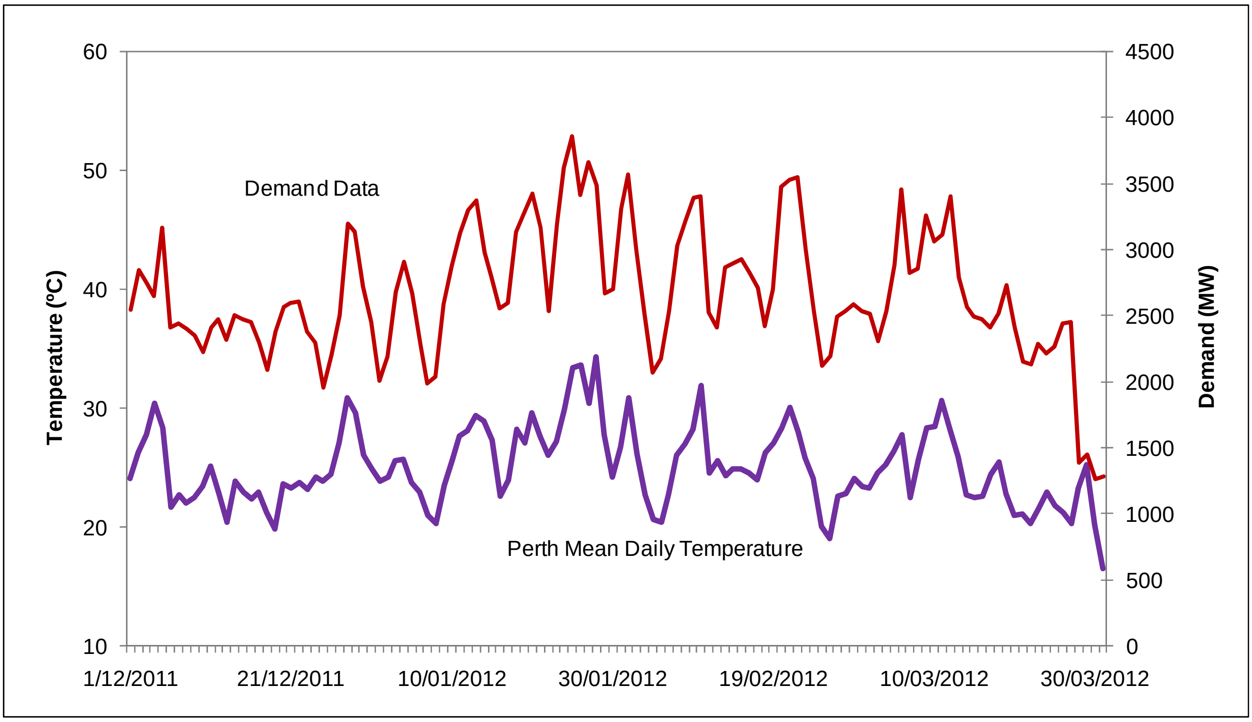
(Source: Bureau of Meteorology)

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.

There were four days when the mean daily temperature exceeded the 90% PoE level, which is the same number of instances as in the 2010/11 Hot Season. The mean daily temperature exceeded the 50% PoE level on three occasions during the Hot Season. However these all occurred in January, during the school holidays, with only one occasion falling on a business day. This occurred on 25 January, the business day immediately preceding the Australia day public holiday. The mean daily temperature did not reach the 10% PoE level during the Hot Season.

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

Figure 2 – Perth Mean Daily Temperature and Daily Peak Demand



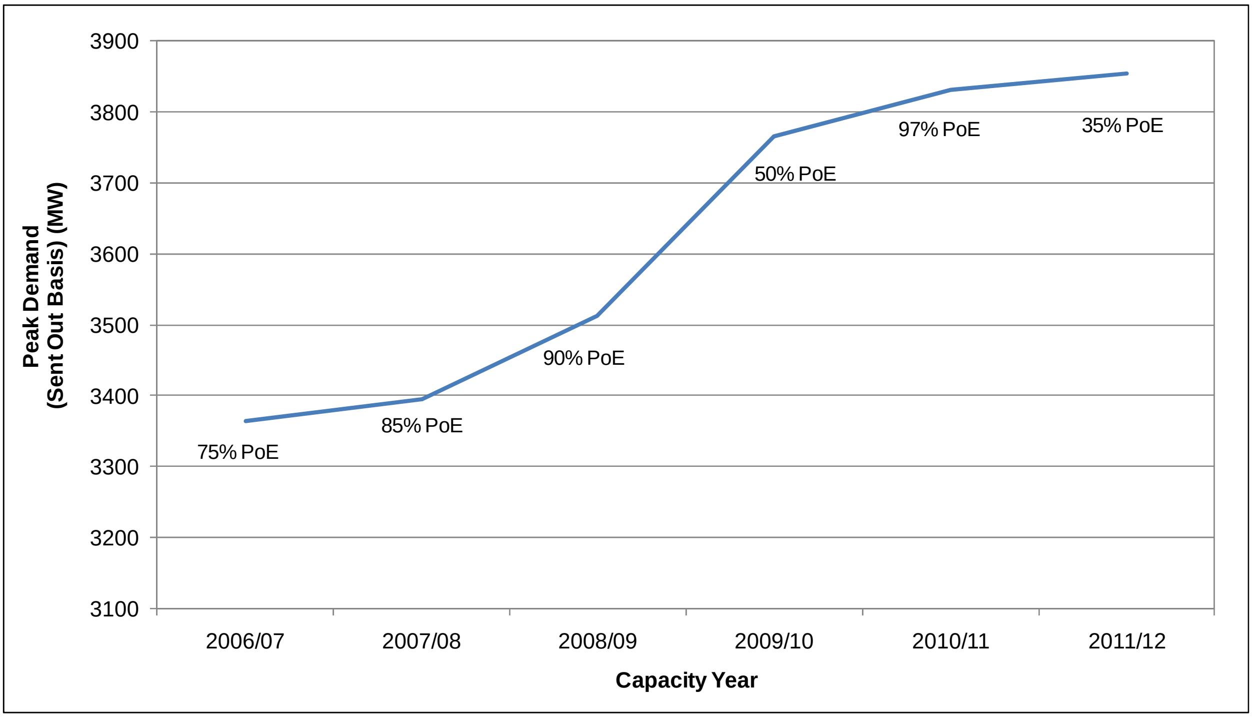
The maximum sent out generation for 2011/12 was 3,854 MW on 25 January 2012. The mean daily temperature on 25 January was 33.3°C, making it the third hottest day in the summer, corresponding to a PoE level of approximately 35%. This was preceded by a mean daily temperature of 29.9°C on the previous day.

This is the first time that the SWIS peak demand day has fallen outside of February or March since 2002. As noted above, the peak demand event occurred late in the afternoon before the Australia Day public holiday.

Unlike the 2010/11 peak demand day, which coincided with a gas supply disruption, there was no dispatch of Demand Side Programme (DSP) facilities on this day. DSP's were only dispatched on a limited basis for facility testing purposes during the 2011/12 hot season.

Figure 3 shows the annual peak demand for each year from 2006/07. The peak demand of 3,854 MW is 0.6% higher than the 2010/11 summer peak of 3,831 MW. The PoE level of the peak demand day is shown for each year.

Figure 3 – Annual Peak Demand and PoE Level of Peak Day



The peak demand of 3,854 MW is significantly below the 2011/12 peak demand forecasts published in the 2007 to 2011 SOO's. Table 1 shows the difference between the actual peak demand in 2012 and forecasts provided in the SOO's since 2007. The 50% PoE forecasts are chosen for comparison as these most closely relate to the temperature conditions on the peak demand day.

Table 1 – Comparison of 2011/12 Peak Demand with Forecasts

Maximum demand = 3854 MW		Variance (MW)	Accuracy (%)
2007 SOO	4166	312	8.1%
2008 SOO	4555	701	18.2%
2009 SOO	4339	485	12.6%
2010 SOO	4401	547	14.2%
2011 SOO	4181	327	8.5%

Various factors have contributed to the 2011/12 peak demand being significantly lower than forecasts provided in previous SOO's:

- As noted above, the 2011/12 summer represents the first occurrence of an annual peak demand event occurring outside February or March since 2002. Demand is typically lower in January during school holidays. Demand is also typically lower on days adjacent to public holidays. Indicative comparisons from 2007 and 2008 suggest that demand would have been 100-200 MW higher if equivalent temperature conditions had been experienced during February or early March.[1]

- The forecasts provided for 2011/12 in the 2011 SOO included an allowance for two major block loads that have experienced construction delays. These delays represent 117 MW from the 2010 and 2011 forecasts that has not yet been realised.
- The 2008 forecasts included 260 MW for projects that have yet to commence operation, representing iron ore mines in the Mid-West and Great Southern regions that have been significantly delayed since the onset of the Global Financial Crisis (GFC).
- The forecasts published previously have not specifically considered solar PV penetration. The impact of small-scale PV was not material previously and limited information has been available regarding public policy changes and their impacts. However, penetration has grown sharply in recent years, supported by feed-in tariffs and reducing system costs. Small-scale PV generation is not separately measurable by the IMO and is observed as reduced consumption, having a dampening effect on the measured peak demand. The IMO estimates that the reduction in peak demand for the recent summer was approximately 50 MW.

Chapter 4 contains considerable discussion of emerging trends affecting electricity demand and the significant challenge of forecasting the commencement of new large loads in recent years.

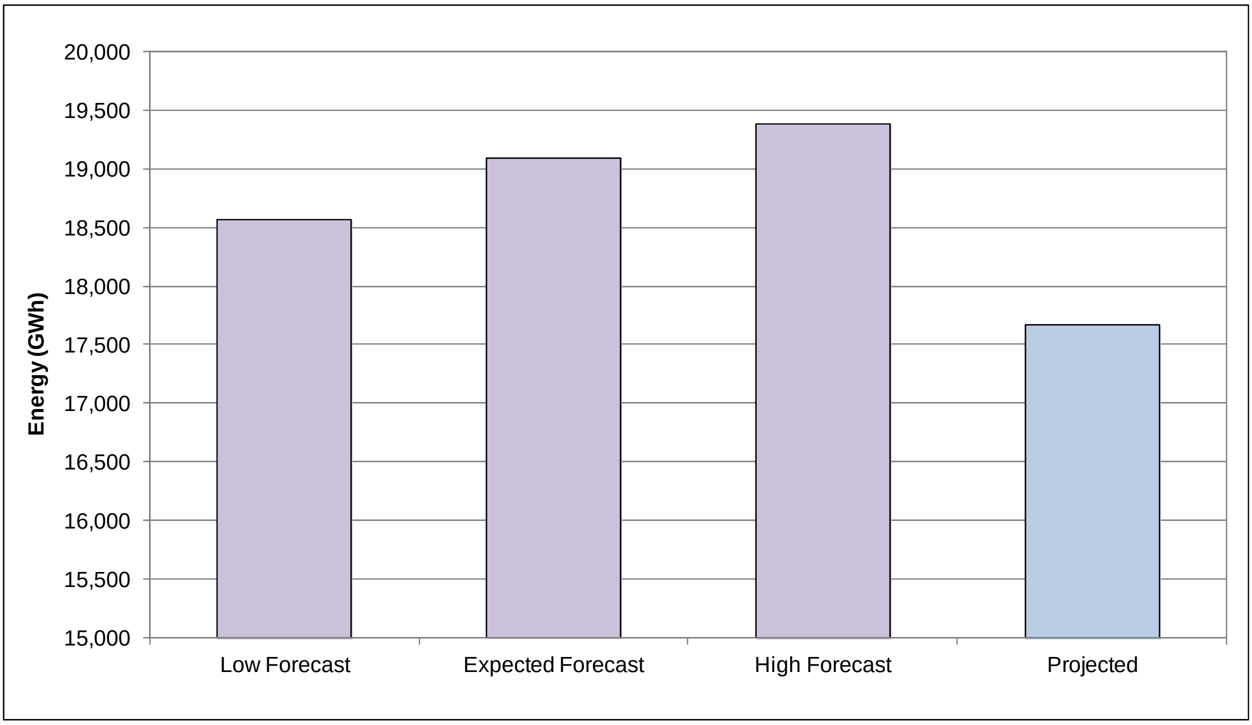
2.2 Actual Sent Out Energy

Despite the high average summer temperature, more than 1°C above the historical average, estimated energy consumption for 2011/12 is significantly below the forecasts published in the 2011 SOO.

Figure 4 compares energy forecasts from 2011 for Expected, Low and High growth cases for the 2011/12 financial year[2] with the projected energy consumption for the same period of 17,673 GWh. This estimate comprises nine months of actual data plus three months of estimated energy consumption to the end of June 2012.

[1] These years were selected as the 25th of January fell on a weekday and high maximum temperatures were experienced (39°C and 37°C respectively). Demand on these days was compared to similar temperature days in February and March of the same year.
[2] The annual energy forecasts published in the 2011 SOO are for the Capacity Year (1 October to 1 October). NIEIR also produces financial year forecasts for the IMO – these are published this year in Appendix 5.

Figure 4 – Comparison of Projected and Forecast Sent Out Energy, 2011/12 Financial Year



The late arrival of new block loads and growth of solar PV generation have been significant factors in the energy consumption being below forecast. The IMO estimates that the aggregate consumption of three new loads that were included in the forecasts will be more than 700 GWh below forecast, while the embedded solar PV generation is estimated to contribute in excess of 200 GWh.

The blue line in Figure 5 shows the total sent out energy by financial year since 2007/08, after deducting consumption from new major loads that have commenced operation during that period. The projected 2011/12 figure is indicative only, including nine months of data from the current financial year plus the final three months of the 2010/11 financial year.

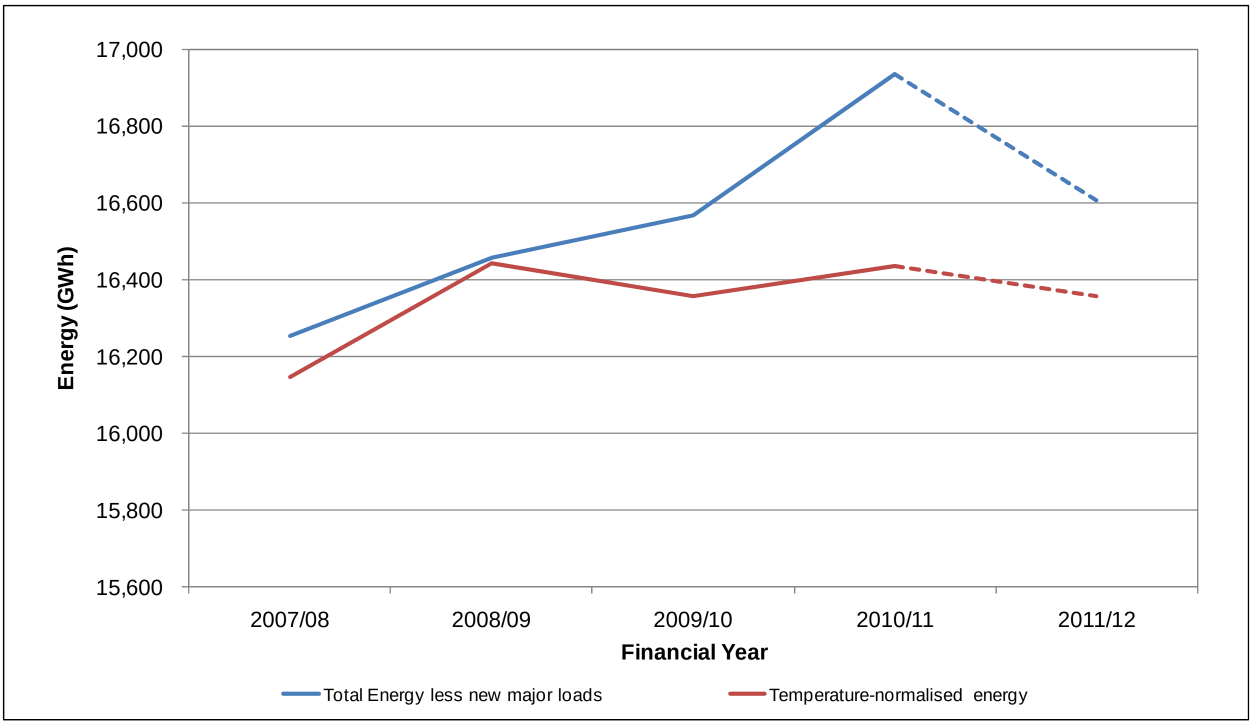
However, the actual sent out energy quantities are sensitive to temperature, both in summer and winter. Consequently, the National Institute of Economic and Industry Research (NIEIR) has normalised this data for the effect of temperature, which is reflected in the red line. This data shows that, after adjusting for new major loads and temperature, growth in energy sales has been flat since 2008/09. This flat growth trend has been masked by above-average temperatures during the last three summers, but has been identified by NIEIR as part of the causal analysis of changes in the forecasts.

A number of factors are likely to have contributed to this change:

- Small-scale solar PV systems are seen at the wholesale level as reduced consumption.

- The restricted availability and increased cost of finance since the onset of the GFC in late 2008 has hampered investment for small-to-medium enterprises in Western Australia since that time.
- The increases in regulated electricity tariffs, which commenced from April 2009, have seen prices for residential customers increase by 57% in the last three years, with similar increases in the regulated tariffs that apply to small commercial and industrial customers.
- Energy efficient appliances, energy efficiency programs and public awareness campaigns are driving behavioural change amongst consumers.

Figure 5 – Sent Out Energy, Adjusted for New Major Loads and Temperature



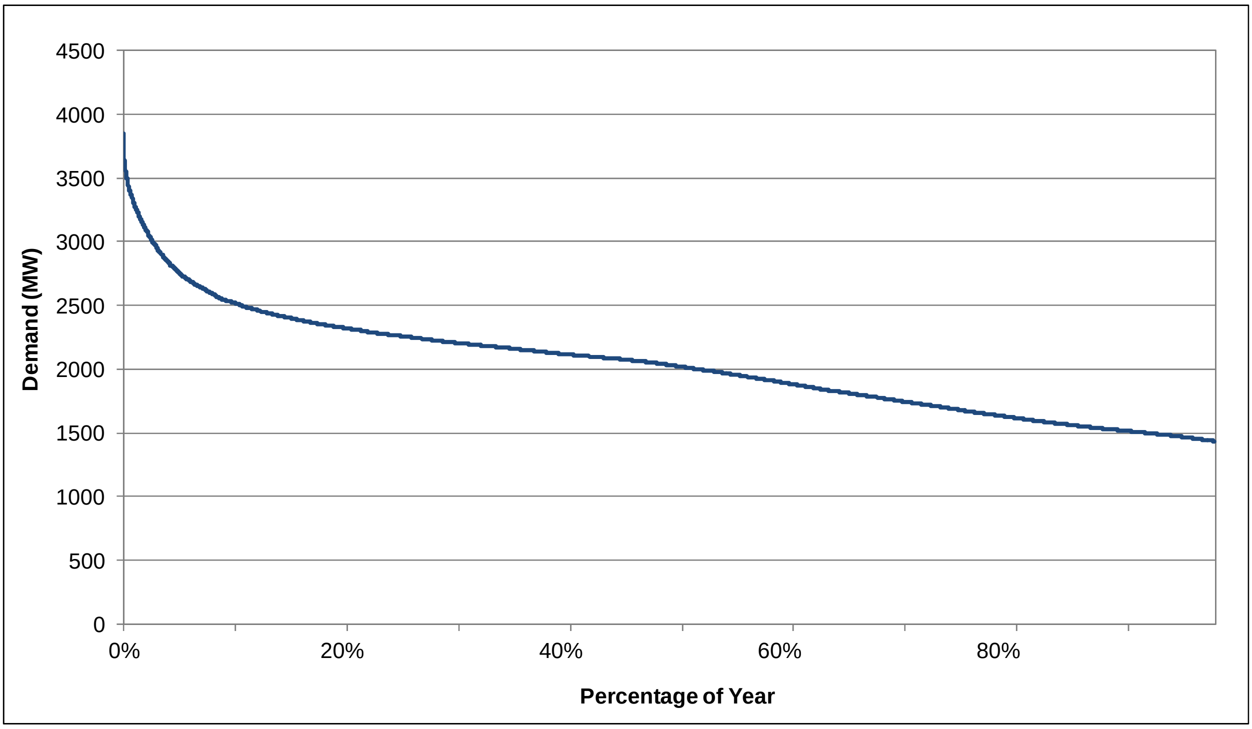
2.3 SWIS Load Duration Curve

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 6, which shows the load duration curve for the period from April 2011 through to March 2012. During this period, the load exceeded 90% of the annual maximum (i.e. 3,469 MW) for only 32 half-hour trading intervals, representing less than 0.4% of the year. Similarly, the load exceeded 80% of the annual maximum (i.e. 3,083 MW) for only 2.1% of the year. This indicates that a significant level of generation, DSM and network capacity is only utilised for a few hours or days each year.

Figure 6 – Load Duration Curve April 2011 to March 2012



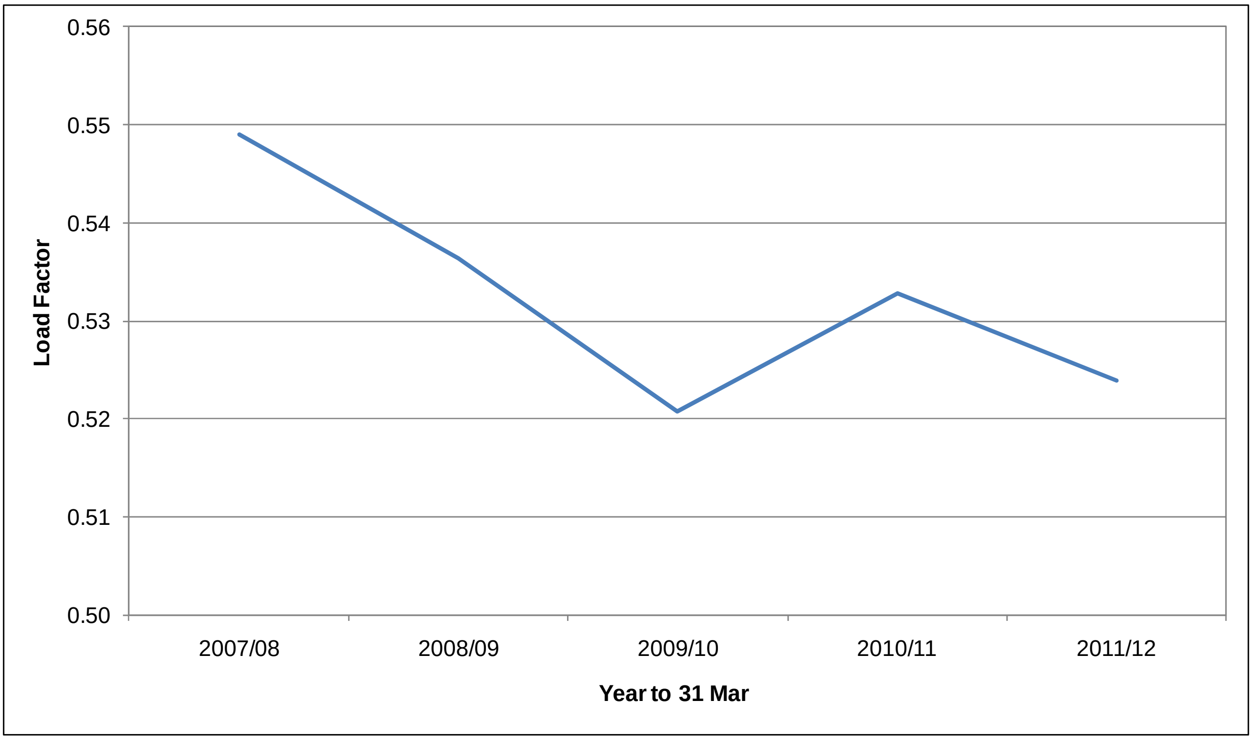
Other observations from this figure are that:

- The mean load over the year was 2,019 MW, which is 52% of the maximum demand compared with 53% last year.
- The minimum load was 1,313 MW at 3:30 AM on 11 October 2011 compared with 1,283 MW last year.

In recent years, the average load factor for the SWIS has been trending downwards, as shown in Figure 7, though the last two years have not continued that trend. The higher 2010/11 load factor reflects the sustained high temperatures through that summer with a relatively cool peak demand day (maximum temperature of 37.5°C). The 2011/12 load factor reflects the occurrence of the peak demand day in January and is higher than would be the case had equivalent temperature conditions been experienced during February or early March.

This downward trend demonstrates that peak demand has grown at a faster rate than average demand. Based on this year’s forecasts, this trend is expected to continue.

Figure 7 – Load Factor for Year Ending 31 March



2.4 Typical SWIS Daily Load Shape

Electricity demand varies substantially through each day with overnight loads being markedly lower than daytime demand. Figure 8 illustrates this, showing the level of demand in each trading interval on 25 January 2012, 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.

In the period from April 2011 to March 2012, the largest intra-day differential between maximum and minimum load was 1,944 MW, which occurred on 24 January 2012. The minimum load on this day was 1,677 MW and the maximum load was 3,621 MW. The lowest intra-day differential of 493 MW occurred on 7 January 2012, with a minimum load of 1,489 MW and maximum load of 1,982 MW.

Figure 9 shows the maximum and minimum intra-day demand differentials for the previous five years.

Figure 8 – Daily Load Curve 2012 Peak Demand Day (25 January 2012)

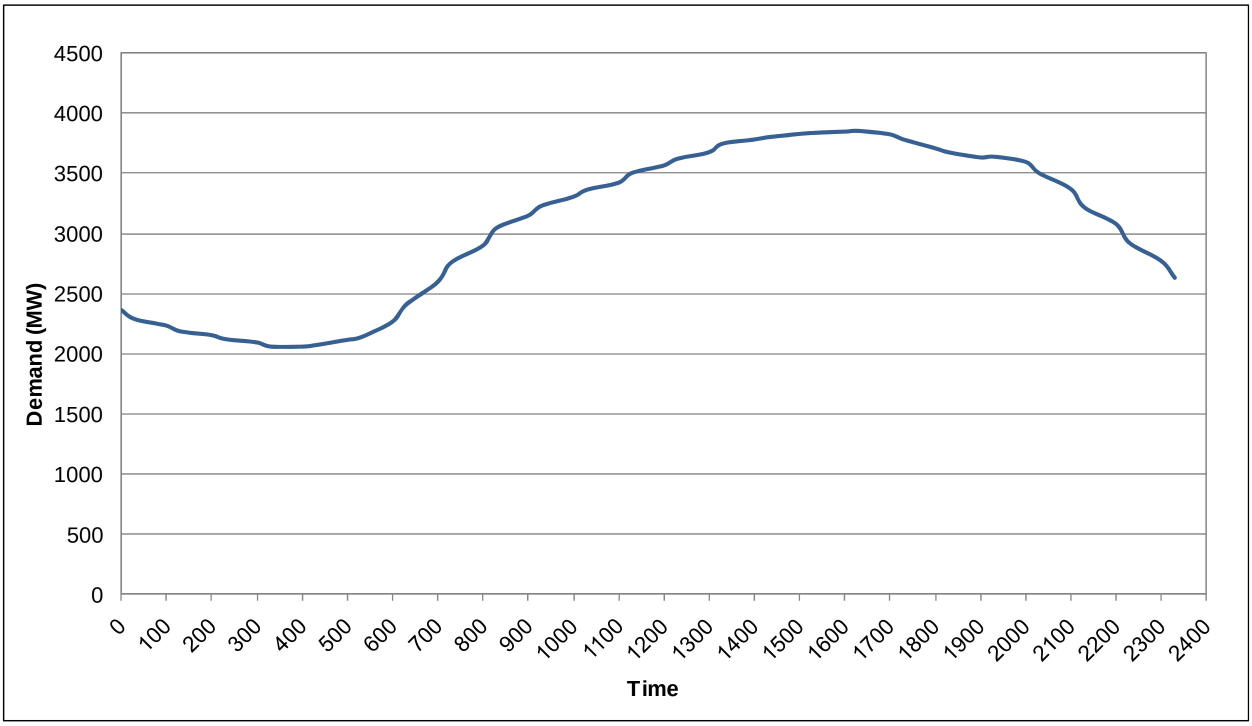
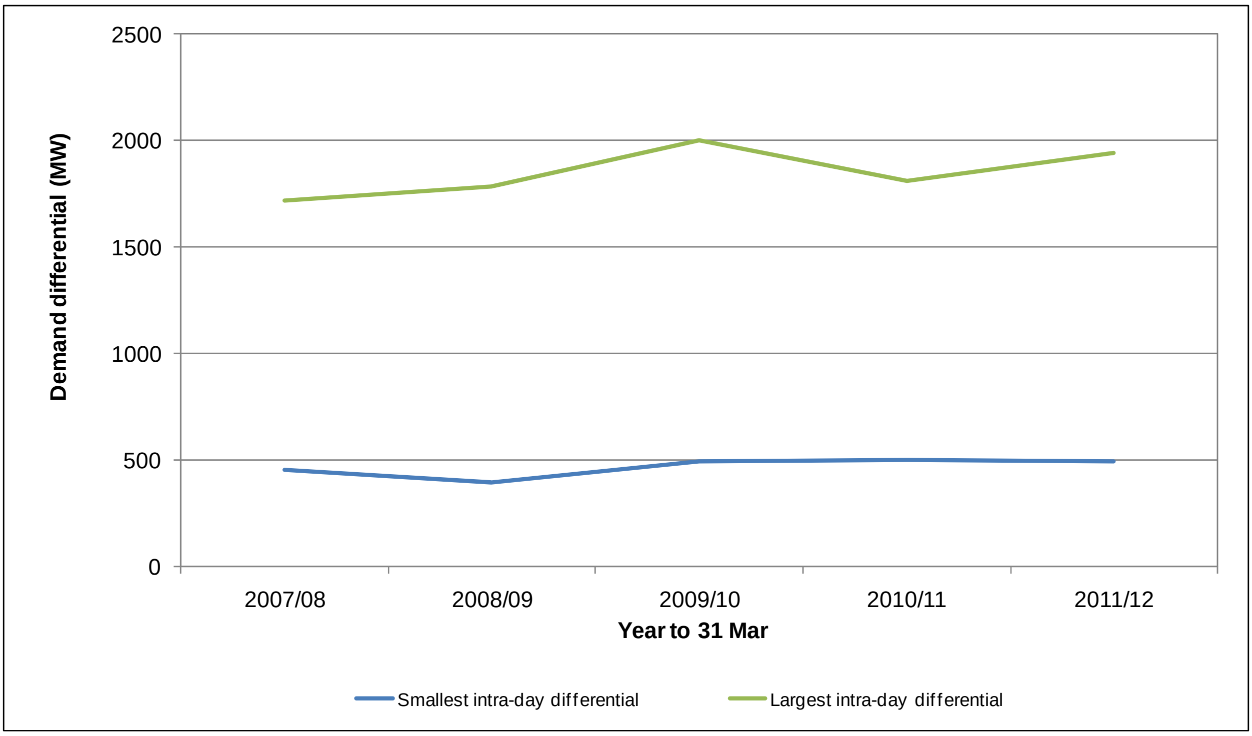


Figure 9 – Intra-Day Demand Differential for Year Ending 31 March



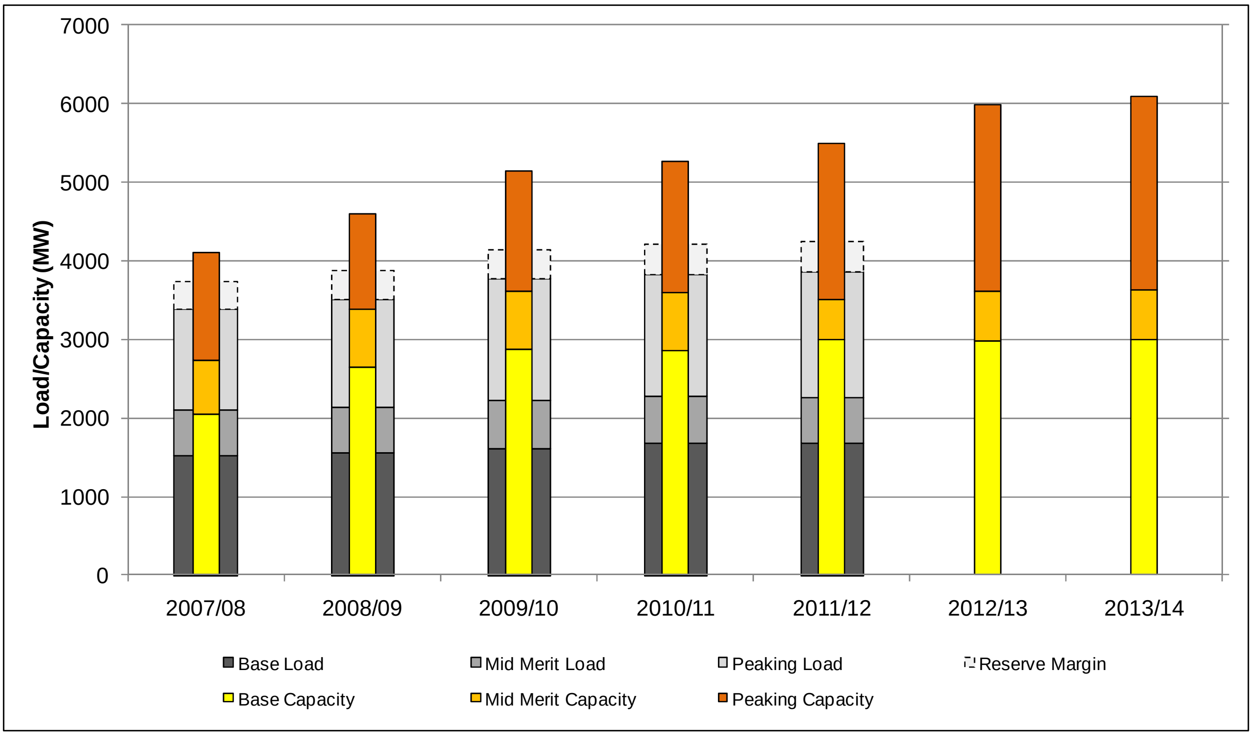
2.5 Information on Market Generators

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 10 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 based on historical operating practices.

Figure 10 – SWIS Load Characteristics and Capacity Mix



As can be seen in Figure 10, substantial investment was made in new base load generation capacity for the SWIS in the early years of the WEM (2006 through 2009). This has led to a surplus of this capacity in the near term and has required some cycling of base load generation plant during periods of lower demand (e.g. overnight). The level of base load capacity has remained steady at around 3,000 MW since 2011/12, as would be expected given the surplus of this capacity.

Peaking capacity has grown substantially from 2010/11 up to 2013/14. The introduction of substantial volumes of DSM and liquid-fuelled generation in recent Reserve Capacity Cycles has contributed substantially to the rapid increase in peaking capacity from 2008/09 to 2013/14. As is demonstrated in Figure 10, this growth in peaking capacity fits well with the SWIS load profile.

The level of DSM appears to be approaching saturation and it is anticipated that the rate of growth in DSM will materially slow following substantial growth in the last two Capacity Years. The level of DSM penetration in the SWIS now represents a similar level to that of other electricity markets where the DSM market is mature. The average size of customers that are being contracted to provide DSM is reducing, and the number of Expressions of Interest for new DSM capacity has reduced from previous years.

2.5.2 Capacity Credits by Fuel Type

Diversity of fuel types is desirable in an electricity market as it improves the management of operational risk and supports competition between technologies.

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. These facilities are heavily reliant on income from the energy market.

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. These facilities will be reliant on Reserve Capacity payments.

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

While there have been some changes to the mix of fuel types, the healthy fuel mix has been maintained since the introduction of the Reserve Capacity Mechanism. Figure 11 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 A and B plant.

A key observation from this figure is that the vast majority of capacity continues to be coal or gas-fired. The proportion of energy generated from these fuels in the SWIS is even higher, representing nearly 95% of energy produced as shown in Figure 33 later in this report. From the 2011/12 Capacity Year, the percentage of Capacity Credits assigned to liquid-fuelled plant and DSM has increased significantly, as noted above.

The percentage of dual-fuel capacity remains low. As discussed in Section 7.4, the Gas Supply and Emergency Management Committee (GSEMC) recognised the need for incentives for investment in dual fuelled generation plant and the IMO is currently awaiting policy direction from the Public Utility Office.

Figure 11 – Percentage of Capacity Credits by Fuel Type

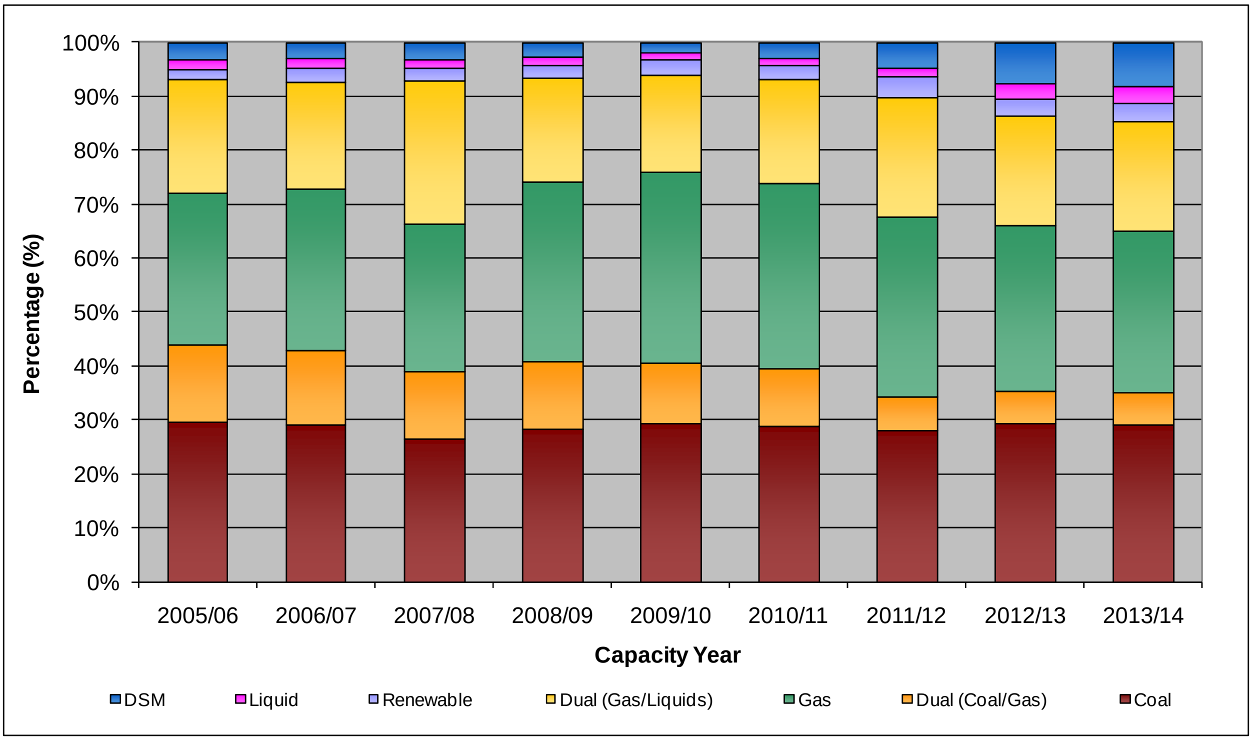
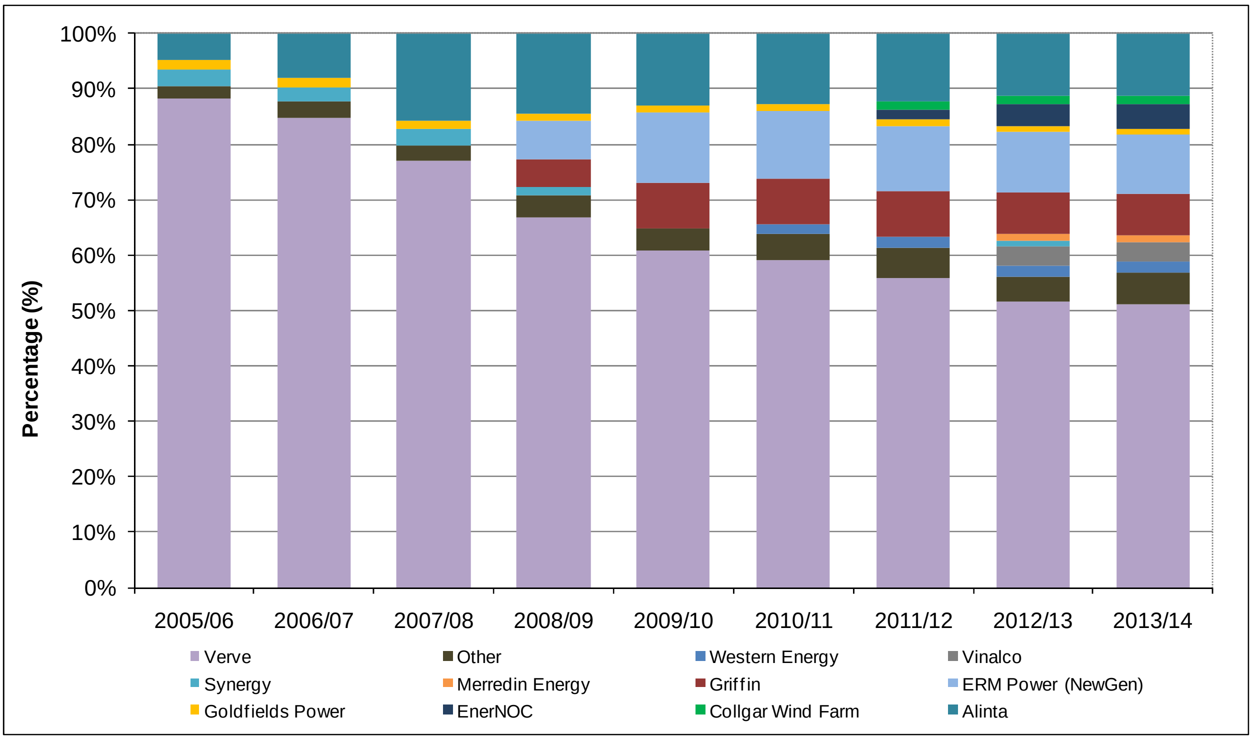


Figure 12 – Capacity Credits by Market Participant (minimum 1% market share)



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[3]; and
- the Reserve Capacity Mechanism.

Figure 12 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 51% in 2013/14. The graph also shows growth in the number of Market Participants providing capacity to the SWIS.

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 13, the average age of generating capacity on the SWIS generally fell in the initial years since market start. This reflected the introduction of new capacity and the retirement of older plant such as Verve Energy's Kwinana Stage A and B facilities.

However, this trend has reversed primarily due to the refurbishment of the Muja AB facilities (originally commissioned in stages in the 2nd half of the 1960's) for the 2012/13 Capacity Year. Consequently, the average age of generation capacity in the 2013/14 Capacity Year will be higher than at the commencement of the market.

There will continue to be fluctuations in the average age from year to year, depending on the addition of any new capacity, upgrades to existing facilities and retirement of any plant.

Figure 14 shows the planned and forced outage rates displayed as a percentage of the allocated Capacity Credits in the market. The total rate of facility outage rates appears to have stabilised with monthly outage rates as high as 25% outside the summer period compared to rates of approximately 5% during the peak demand season.

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[3] 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), though these facilities have now been transferred to Vinalco. A copy of the Ministerial Direction is available at http://www.imowa.com.au/cap-credit-info.

Figure 13 – Average Age of Generation Capacity

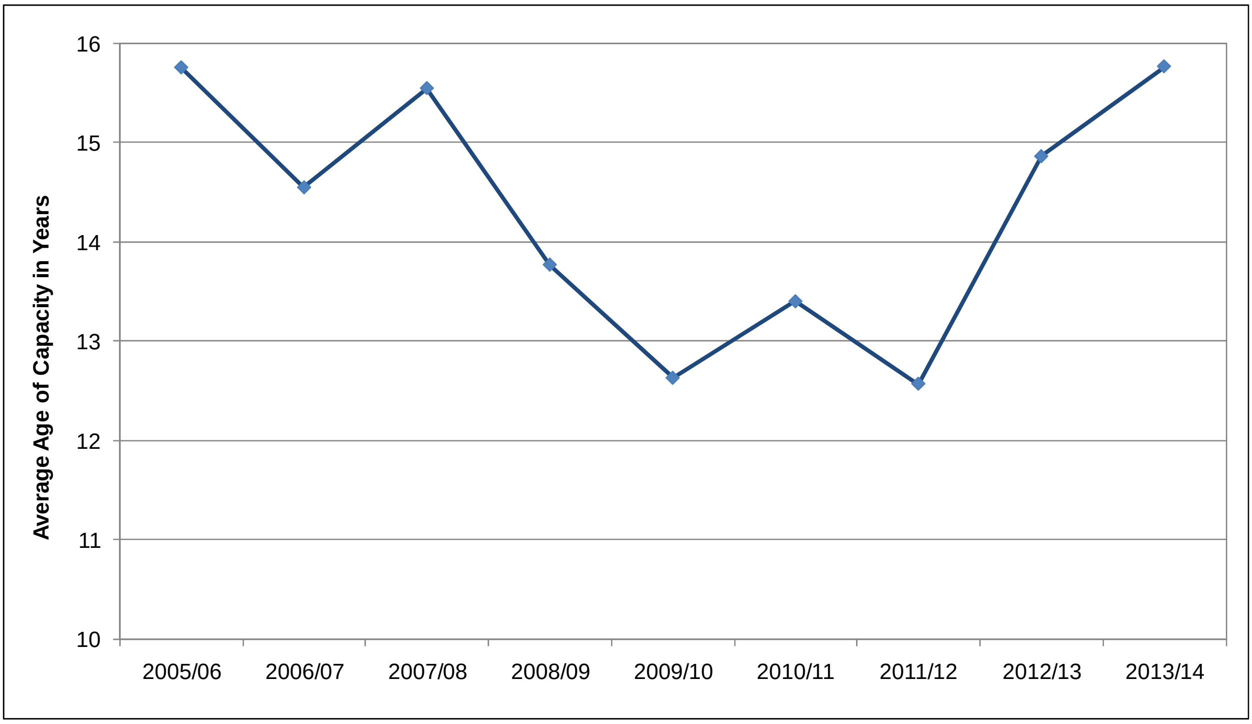
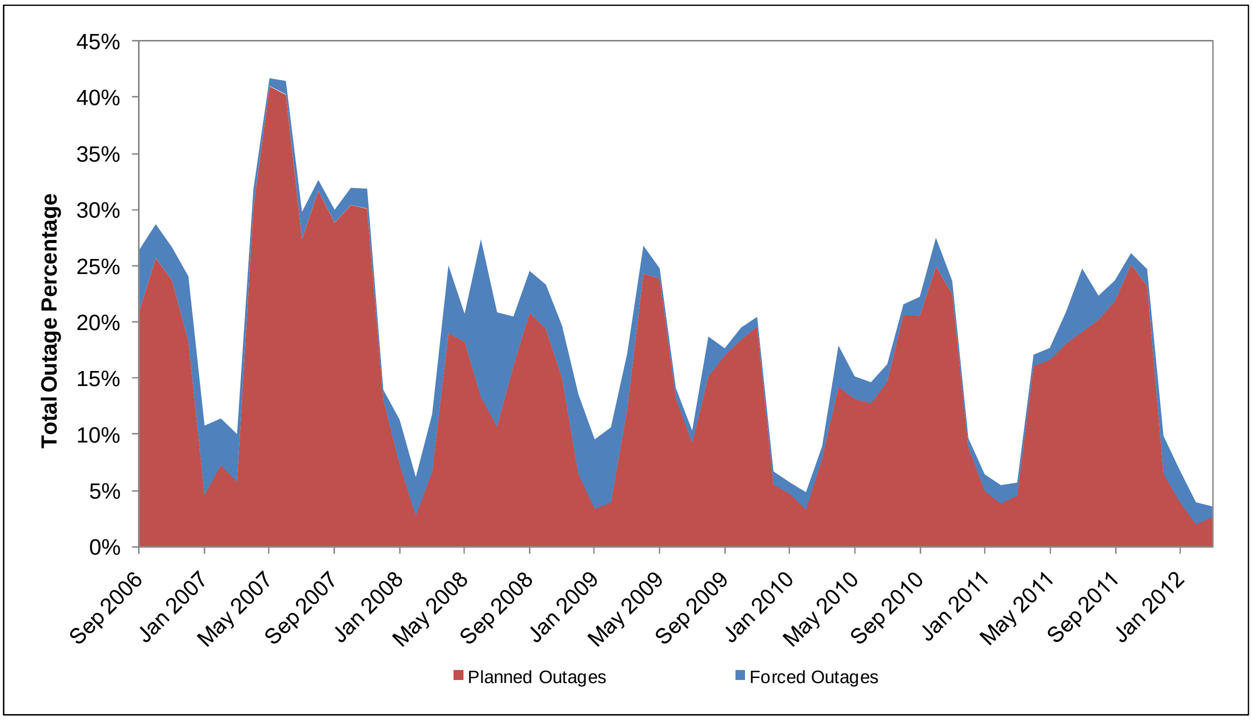


Figure 14 – Monthly Average Outage Percentage



2.6 Energy Pricing in the Wholesale Electricity Market

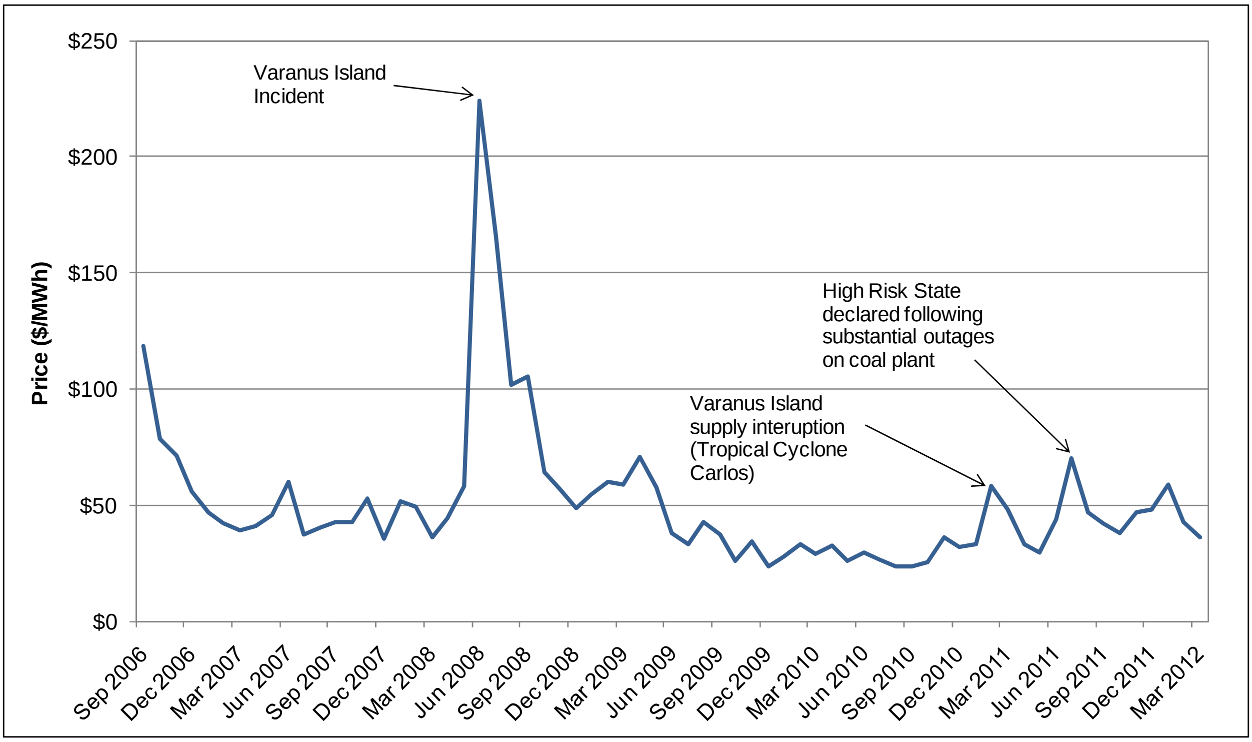
The energy trading component of the Wholesale Electricity Market (WEM), the Short-Term Energy Market (STEM), has been in operation since Energy Market Commencement (EMC) on 21 September 2006. In that time, the energy price has proven to be responsive to changes in the supply-demand balance in the SWIS.

As the energy trading mechanisms in the WEM have matured, a general increase in trading quantities and downward pressure on prices has been observed, reflecting increased competition in the WEM.

Figure 15 shows the monthly average STEM price since EMC. 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 dependency of the SWIS on gas-fired generation is highlighted by price spikes caused by two disruptions to the Varanus Island gas supply. The larger of these disruptions, caused by a gas explosion on 3 June 2008, caused severe price spikes between June and August due to gas supply restrictions during that time. The price spike during February and March 2011 was caused by the shorter one-week interruption of supply from Varanus Island triggered by Tropical Cyclone Carlos.

Figure 15 – Monthly Average STEM Price

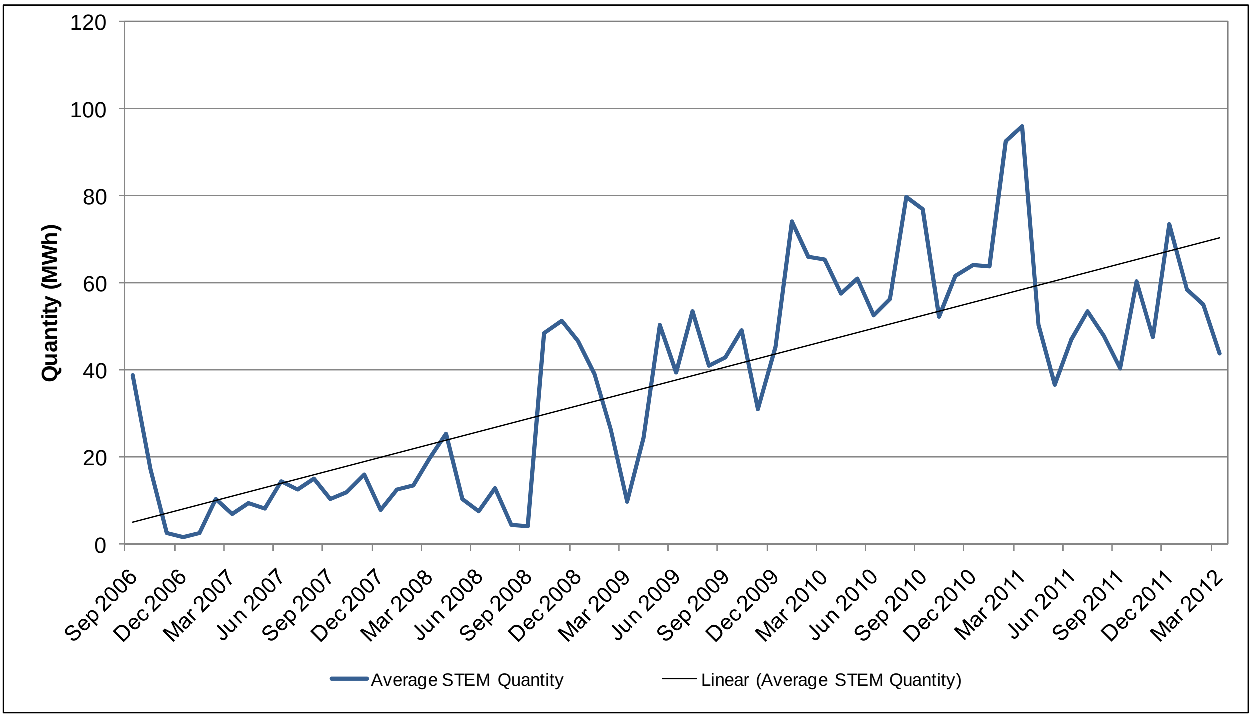


Similarly, higher prices can occur during periods of high plant outage. The impact of any particular plant outage on STEM prices will depend on the particular characteristics of the plant in question and where that plant is located in the merit order. For example, an outage of a base-load power plant might be expected to have a greater impact on market prices compared to an outage of a similarly sized peaking plant.

The impact of outages of base-load plant was observed in July 2011 when as much as 54% of the coal-fired capacity in the SWIS was unavailable. Approximately 200 MW of coal-fired generation was on forced outage for the whole month, while the quantity of coal-fired generation on planned outage approached 900 MW over three Trading Days during the first week of July. STEM prices exceeded $300/MWh on four days during the first week of July, reaching the Maximum STEM Price of $336/MWh on 6 July 2012.

Increased competition is also evident in the growing quantity traded in the STEM. Figure 16 shows an 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.

Figure 16 – Average STEM Quantity Traded (per interval)



Another factor has been a steady rise in the usage of the STEM as a tool for Market Participants to adjust their trading position around their bilateral contracts. Spikes in the quantity traded in the STEM are evident around the commencement of Capacity Years, with the quantity reducing shortly after. These are coincident with the entry of large new facilities into the WEM, suggesting that the owners of these facilities have traded energy in the STEM prior to the commencement of bilateral contracts.

The introduction of the new Balancing and Load Following Ancillary Services (LFAS) markets from 1 July 2012 will provide increased opportunities for Market Participants to compete to provide energy and ancillary services in the WEM.

3. Economic Environment

3.1 Background

Economic forecasts are an important input in electricity demand 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 important to the Western Australian economy and are a key driver in electricity demand growth. The Department of Mines and Petroleum has reported that resource projects worth an estimated $167 billion were under construction or committed as at 31 March 2012, dominated by liquefied natural gas (LNG) and iron ore developments[4].

However, given the high dependence of the Western Australian economy on the resources industry, it could reasonably be expected that growth rates in Western Australia will be more volatile than in other more diversified economies. Activity in the resources sector is highly dependent on economic activity in Asia, in an environment where the recovery has been slower than expected in the US and Europe. At present, political and economic uncertainty in Europe suggests that the recovery will remain fragile as the European economies struggle with high debt and other structural issues.

In addition, in the aftermath of the global economic slowdown some marginal resource development projects have experienced significant delays or cancellation. This reflects a continuing aversion to invest significant capital and debt in speculative projects, as well as the reduced availability and higher cost of finance since the GFC.

While the majority of the resources projects under development are located outside of the SWIS there are some projects that are located close enough to the SWIS to have a direct impact on WEM demand forecasts. Of particular relevance at present are proposed iron ore developments in the Mid-West and Great Southern regions that have substantial power needs. It is expected that the levels of existing and new investment in the resources industry should remain a key driver for energy usage in the SWIS in the medium term.

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 related to the resources industry is 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.

[4] http://www.dmp.wa.gov.au/12410.aspx

- This economic activity has boosted population growth in Western Australia, particularly through interstate and overseas migration during the last 5 years. It is estimated that the population of Western Australia (not all of whom reside in the SWIS) has increased by over 15% during this period, to the current level of approximately 2.4 million people.

This chapter includes discussion on changes in economic outlook which have occurred since the 2011 SOO. A comparison is also provided between NIEIR's forecasts and a number of other publicly available forecasts.

NIEIR's forecasts are prepared using available economic data up to the December 2011 release of the Australian National Accounts by the Australian Bureau of Statistics (ABS), which occurred on 7 March 2012.

3.2 Economic Outlook

Figure 17 and Figure 18 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 2022/23 for the Expected, High and Low growth cases.

NIEIR forecasts that Australia's annual average economic growth over the period to 2021/22 will be at an average rate of 3.0%, compared to a rate of 3.2% forecast in the 2011 SOO. Average growth in the Western Australian economy over the next ten years is forecast to be 3.8% per year, the same rate as forecast in the 2011 SOO.

A year-on-year comparison of 2011 and 2012 GDP and GSP forecasts from NIEIR for the short term is provided later in this chapter (Figure 21 and Figure 22).

While resources investment is predicted to grow significantly over the next two years, this is predicted to be partially offset by a slowing of public expenditure. Inflationary pressures are also expected to dampen domestic demand through to 2015, while the high Australian dollar is predicted to lead to slow growth in the manufacturing sector and high growth in imports. NIEIR forecasts that higher growth rates in the world economy and the easing of inflationary pressures will facilitate a higher growth period for the Australian economy in the second half of this decade.

Despite concerns in Europe and the US, Western Australia's economic growth in 2011/12 has been particularly strong with GSP growth estimated to reach approximately 6.8%, largely driven by the high rate of investment in the resources sector. This growth is forecast to continue at 6.5% into 2012/13, easing slightly to 4.8% in 2013/14 and easing further to 2.6% in 2014/15, before recovering to 4.7% in 2015/16.

Figure 17 – Forecast Australian Economic Growth

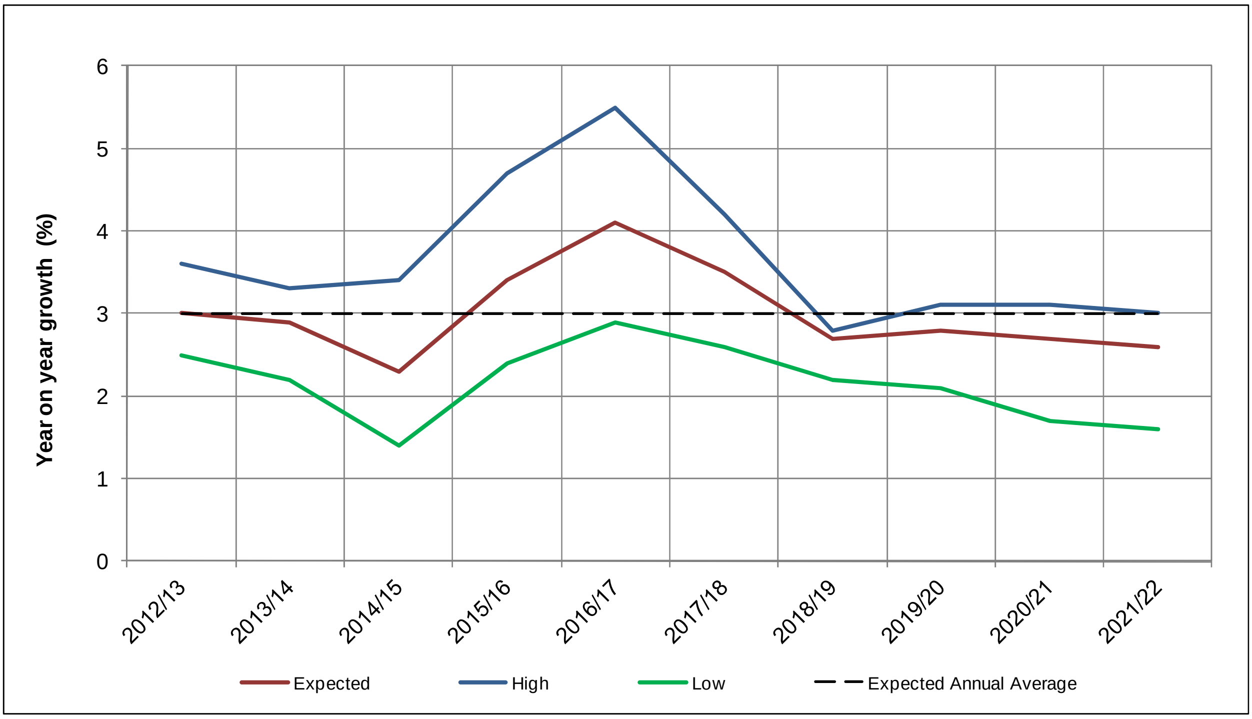
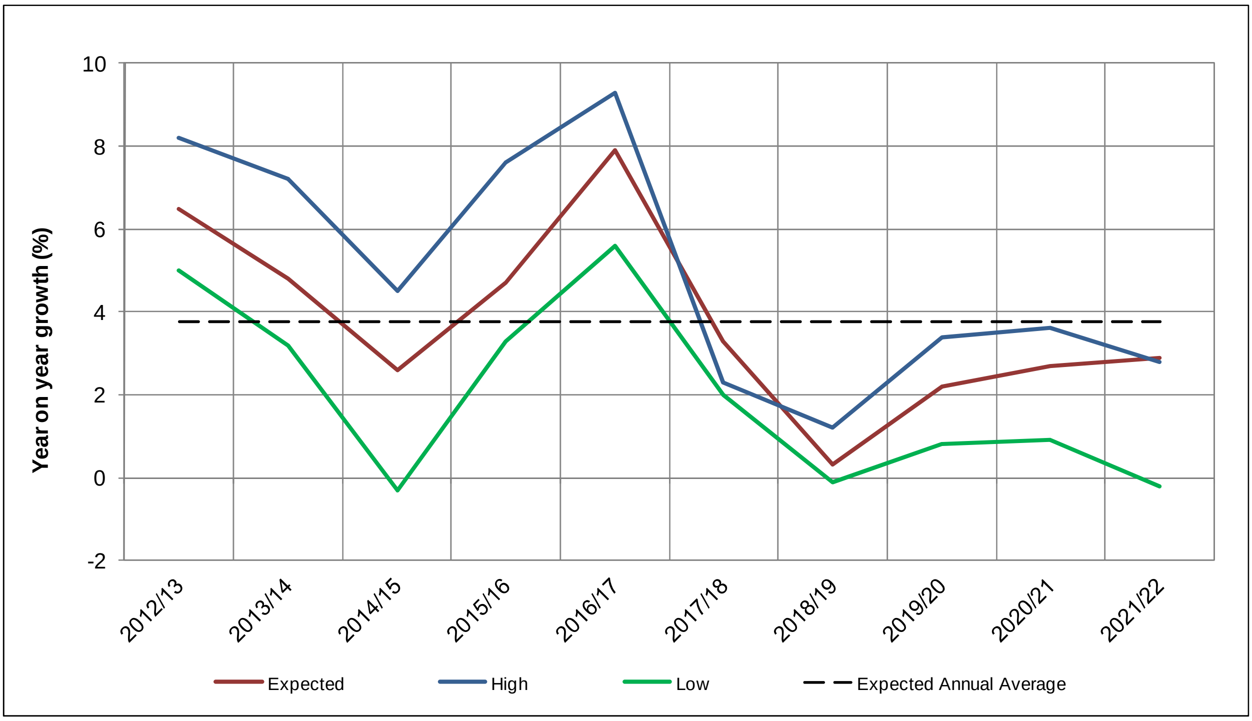


Figure 18 – Forecast Western Australian Economic Growth



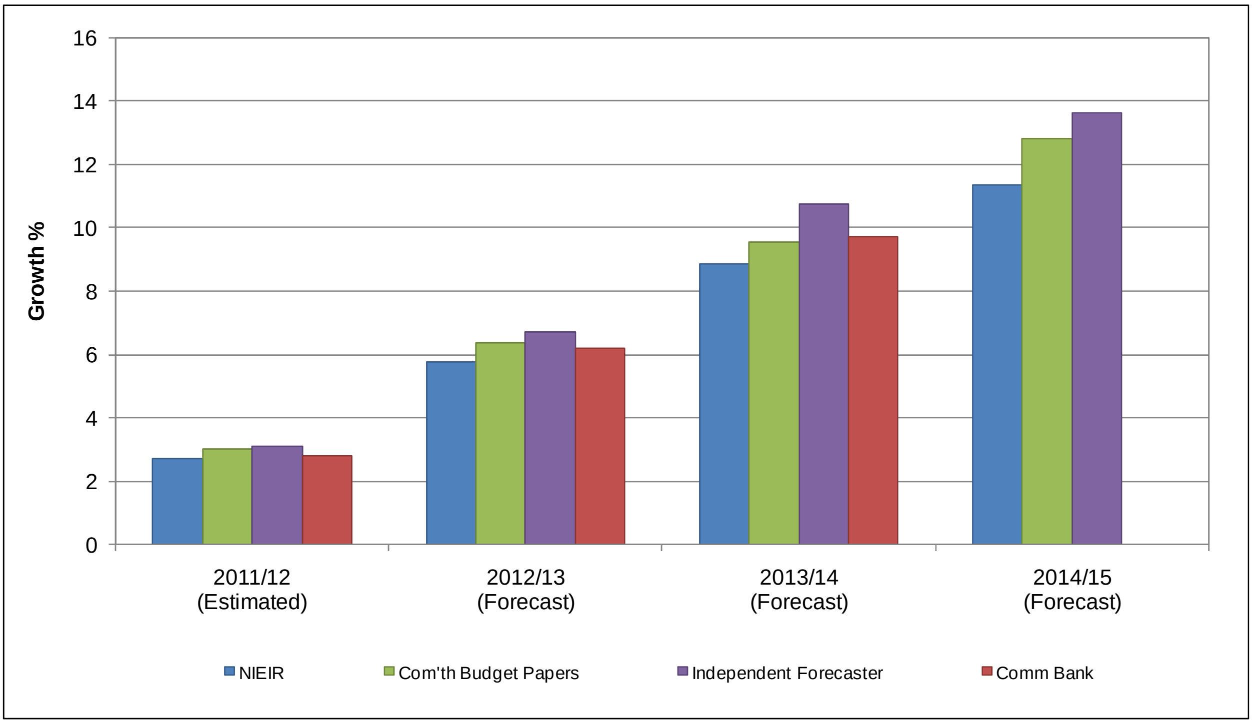
The GSP growth rates presented here are lower than the annual growth rate in State final demand of 13.6% (14.5% in seasonally adjusted terms) that was published by the ABS in the March 2012 Australian National Accounts (released on 6 June 2012). State final demand is essentially a measure of expenditure and differs from GSP, which measures state production and reflects the impact of interstate and overseas trade. The lower GSP growth rate reflects that many of the inputs used in mining investment are drawn from interstate and overseas, as well as financial transfers across the country such as "*tax payments, dividend distributions and wages paid to fly-in fly-out workers from other states*".[5]

Figure 19 compares NIEIR's Australian economic growth forecasts with those of three other organisations:

- the Commonwealth Government Budget Papers (published in May 2012);
- a major independent forecaster[6] (published in April 2012); and
- the Commonwealth Bank Economic Forecast[7] (published May 2012).

This comparison of Australian growth rate forecasts is presented on a compounded basis to smooth out the variations that occur from year to year. The comparison shows a range of forecast outcomes, with NIEIR's forecasts being the lowest displayed.

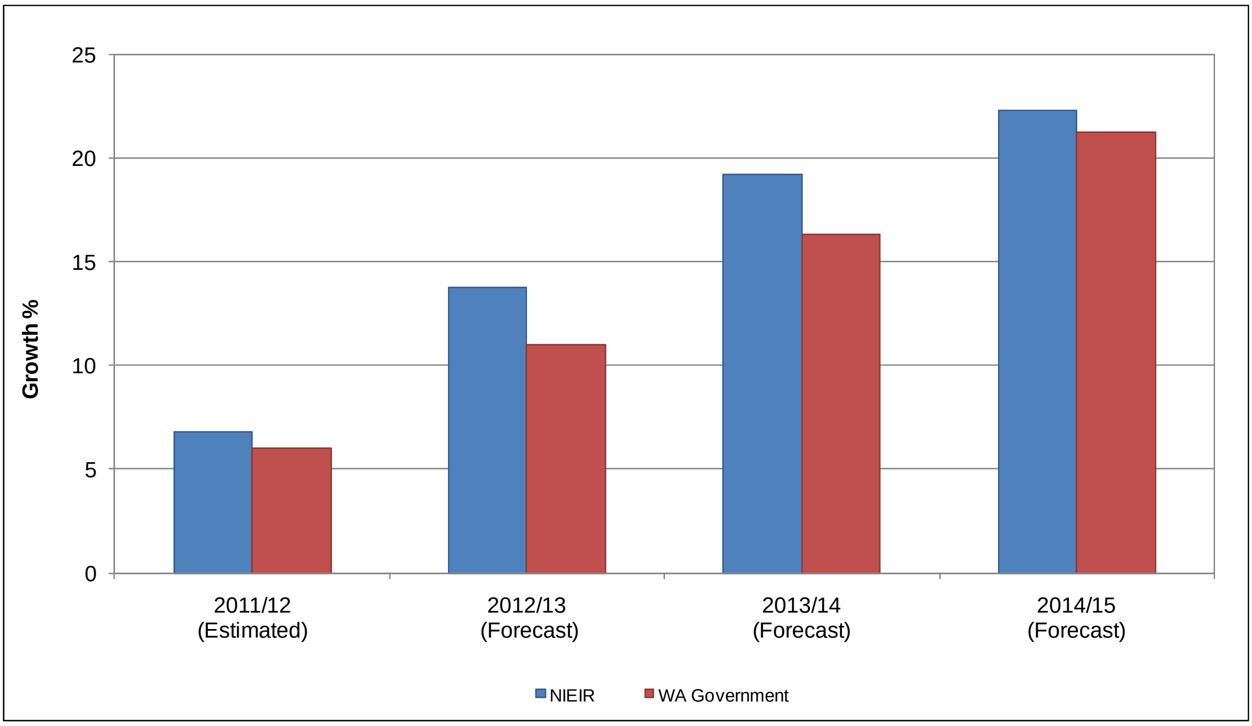
Figure 19 – Compound Australian Economic Growth Forecasts



[5] For further explanation, see Reserve Bank of Australia Bulletin, March Quarter 2012, *The Recent Economic Performance of the States*, available at http://www.rba.gov.au/publications/bulletin/2012/mar/1.html.
[6] The "Independent Forecaster" included in the graph has requested that it not be named.
[7] Note that the Commonwealth Bank forecast extends only to 2012/13, so it is excluded from the 2013/14 comparison.

Figure 20 compares the NIEIR forecasts of Western Australian GSP growth with those published by the Western Australian Department of Treasury in the May 2012 budget papers for the period from 2011/12 through to 2014/15. This comparison is also presented on a compounded basis. While NIEIR predicts higher growth rates of business investment for the 2012/13 and 2013/14 years, Figure 20 demonstrates good agreement between the forecasts over the medium term.

Figure 20 – Compound Western Australian Economic Growth Forecasts



3.3 Differences Between the 2011 and 2012 Economic Forecasts

Figure 21 and Figure 22 compare NIEIR's 2011 and 2012 short-term forecasts for GDP and GSP respectively.

Compared to the forecasts in the 2011 SOO, NIEIR predicts lower economic growth in Australia for the 2011/12 financial year. This revision downwards is largely the outcome of continuing weakness in Europe and the United States through 2011/12 as the developed world emerges more slowly than expected from the after effects of the GFC.

Figure 21 shows that GDP growth is predicted to be lower in 2012/13 but higher in 2013/14, in comparison to last year's forecasts. This reflects the anticipated delay in the economic recovery.

Growth in the Western Australian economy in 2010/11 was weaker than expected. However, the GSP growth forecasts for 2011/12 onwards are significantly higher than what was expected in last year's forecasts, showing significantly higher forecast growth rates up to 2014/15.

The stronger Western Australian growth rates from 2011/12, compared to last year's forecast, reflect:

- continuing strength in private consumption along with low unemployment;
- recovery in property investment from 2012/13 onwards, and
- substantial increases in business investment through to 2013/14 predominantly in the resources industry.

Figure 21 – Comparison of 2011 and 2012 Australian Economic Growth Forecasts

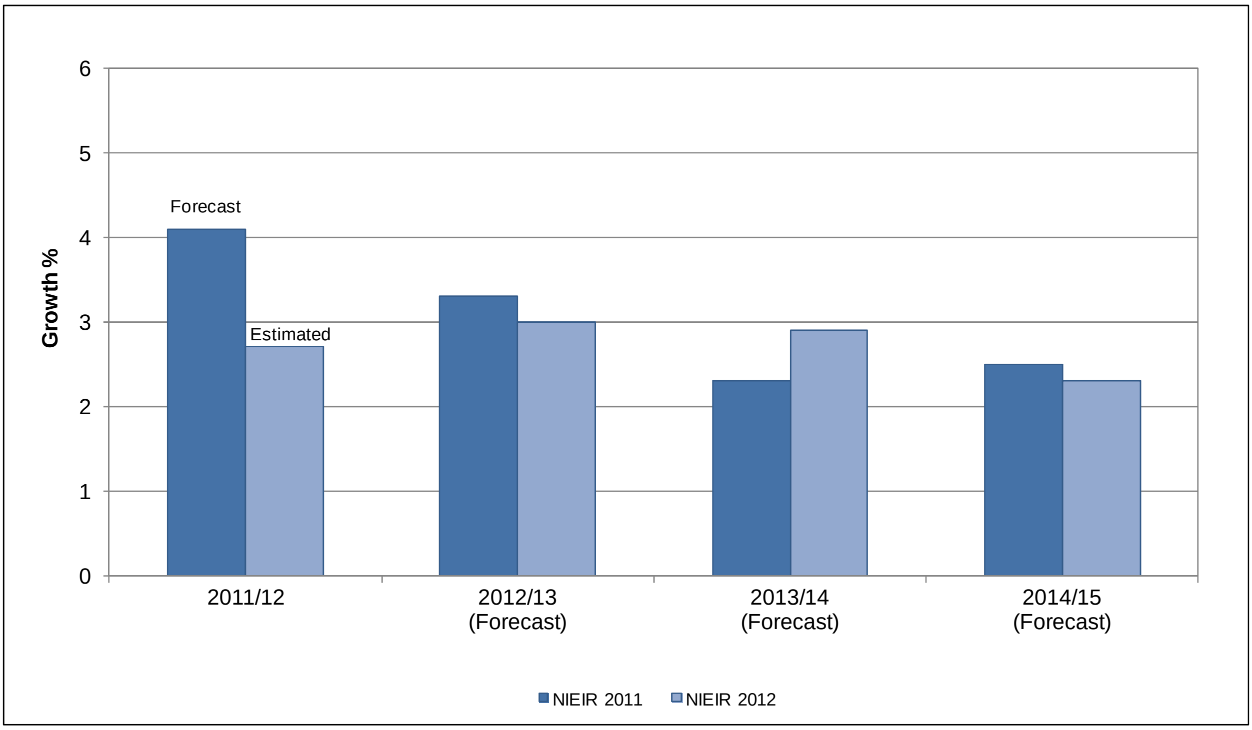
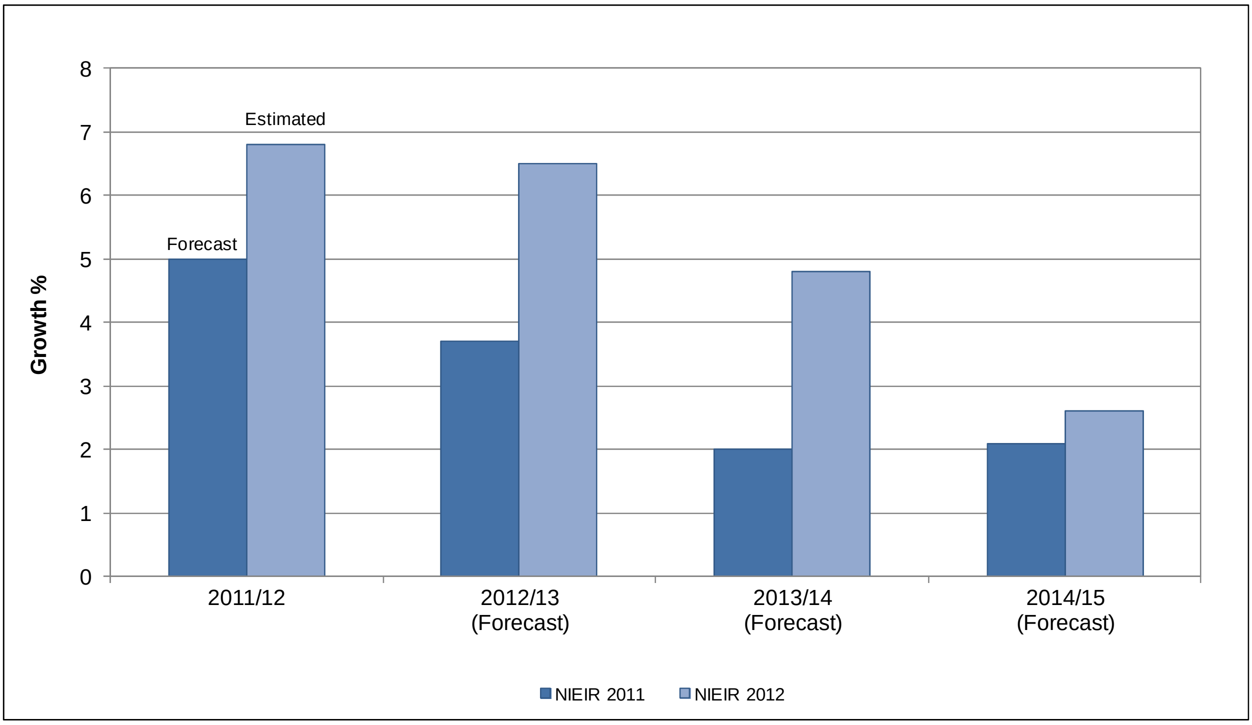


Figure 22 – Comparison of 2011 and 2012 Western Australian Economic Growth Forecasts



4. Peak and Demand and Energy Forecasts 2011/12 to 2022/23

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, underlying economic-based drivers are key inputs to electricity consumption forecasts. 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).

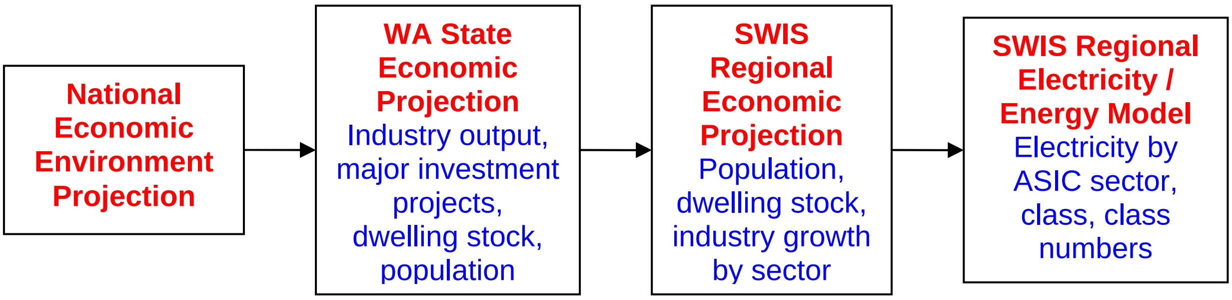
As noted in Section 2.1, mean daily temperatures of 34.6°C, 32.7°C and 31.4°C correspond to the 10%, 50% and 90% PoE temperature conditions respectively.

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 nine 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 23 shows the relationships between the major components of NIEIR's integrated energy modelling systems.

Figure 23 – 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 ABS 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 Modelling of Temperature Sensitive Load

NIEIR's forecasting models include separate consideration of temperature sensitive and non-temperature sensitive load. Temperature sensitive load is dominated by space cooling appliances such as air conditioners, with contributions from refrigeration and ventilation devices.

NIEIR's methodology for estimating the temperature sensitive component of the summer peak demand considers actual air conditioner sales data and the characteristics of available air conditioners. The observed increase in temperature sensitive load is reconciled with this data using a switching regression model[8]. Forecasts of future sales are then developed based on an econometric equation that takes account of construction activity, real income growth and replacement demand.

The impact of air conditioner sales on future peak demand depends on factors such as:

- the proportions of air conditioners that are installed within and outside the SWIS;
- the proportion of air conditioners that are purchased as replacements for older, potentially less efficient, units; and

[8] Switching regression models are described in Stephen M. Goldfeld and Richard E. Quandt, "The Estimation of Structural Shifts by Switching Regressions", *Annals of Economic and Social Measurement*, Volume 2 number 4, October 1973, available at http://www.nber.org/chapters/c9938.pdf.

- the level of utilisation, which may depend on dwelling size, the number of existing air conditioners within the dwelling and consumer behaviour.

The penetration of air conditioning equipment in the SWIS increased dramatically during the first decade of this century, coincident with a period of strong growth in household incomes. Perth also experienced a consistent run of relatively warm summers, excluding 2001/02 and 2005/06. The average annual increase in summer temperature sensitive load from 1999/2000 to 2009/10 was more than four times the annual increase during the early 1990's.

However, more recent market data has indicated that this growth trend in temperature sensitive load has materially changed in the last few years. In response to this change, NIEIR recalibrated its forecasting model in 2011 to:

- lower the assumed quantity of existing air conditioners within the SWIS, recognising that the historical rates of non-SWIS installations and unit replacements may have been higher than originally predicted;
- increase the forecast rates of replacement and non-SWIS installations; and
- lower the assumed utilisation rate.

This recalibration was implemented last year and resulted in reductions in the 10% PoE peak demand forecasts of approximately 300 MW for each year in the ten year forecast horizon.

4.4 New Major Loads

The demand forecast developed by NIEIR incorporates several new major loads identified by the IMO through consultation with the industry. Generally, the IMO considers 20 MW to be minimum threshold for new major block loads.

To assess the size and likelihood that various projects will go ahead, the IMO enters into discussions with developers of these major projects. However, there is always some uncertainty in this assessment relating to:

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

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 dominated by four major mining projects, three of which are magnetite iron ore projects in the Mid West and Great Southern regions. While one of the four projects has now commenced operation, only one of the other three is under construction. The other two have yet to be formally committed.

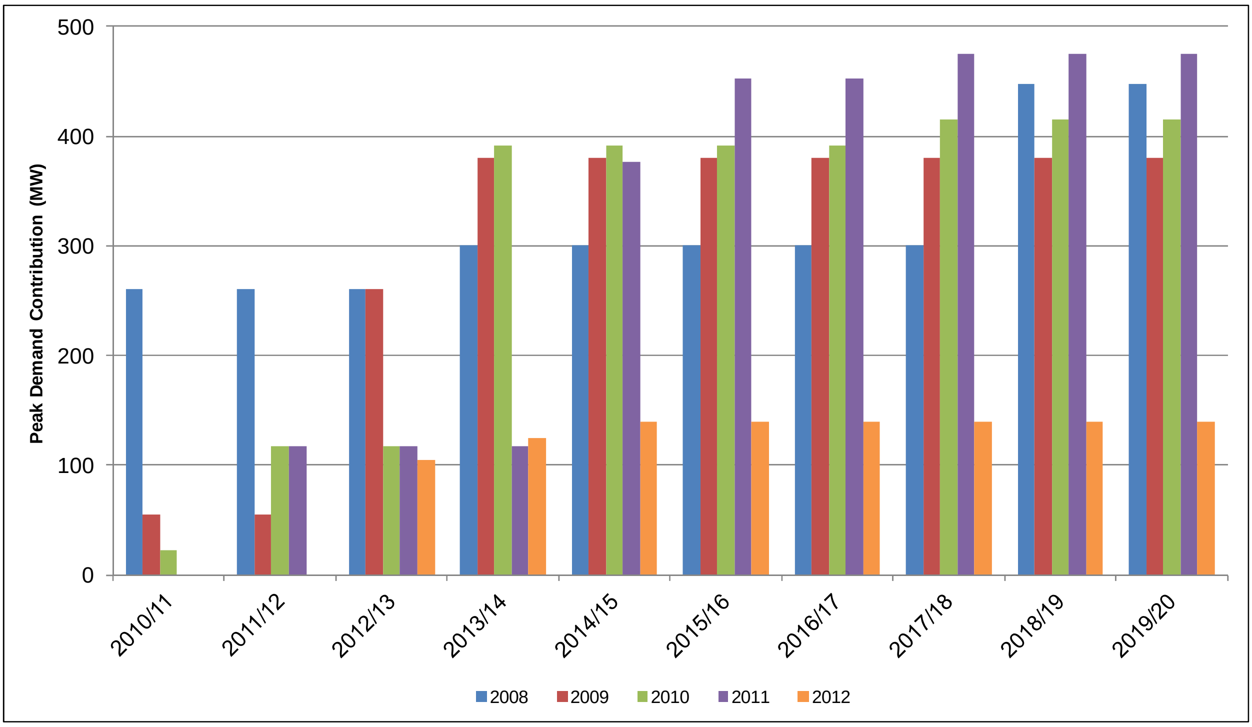
These projects have appeared to be well advanced at the time of their inclusion in previous forecasts. However, large, capital-intensive projects such as these are inherently exposed to delays due to external factors. In response to these project delays and delays in the schedule of Western Power's Mid West Energy Project (MWEP) (Southern Section), the IMO delayed the expected commencement dates for these projects in its forecasts from 2009 to 2011.

Following reassessment of the status of the iron ore developments that have yet to be committed, and considering the lack of demonstrable progress, the IMO has shifted these projects into the High growth forecasts this year and delayed their introduction into the forecasts. As a result, the IMO has considered that the Mid West Energy Project (Southern Section) will be in operation in advance of these projects being completed.

In addition, the IMO has observed that energy consumption at the projects that have commenced operation has been lower than originally projected. Consistent with this observation, the IMO has reduced the allowance for each of the new mining loads in this year's forecasts.

The impact of these delays on the peak demand forecasts is shown in Figure 24. This graph shows the total allowance for large loads that has been included in the peak demand forecasts from 2008 to 2012, after excluding any loads that have now commenced operation.

Figure 24 – New Block Load Allowances for Future Projects



4.5 Small-scale Solar PV

The penetration of small-scale solar photovoltaic (PV) generation has increased markedly in the last few years. Government subsidies, including feed-in tariff schemes, and reducing system costs have contributed to this growth.

Forecasts developed in previous years have not specifically considered the impact of small-scale PV generation, largely due to the lack of available information from Government agencies and State owned utilities.

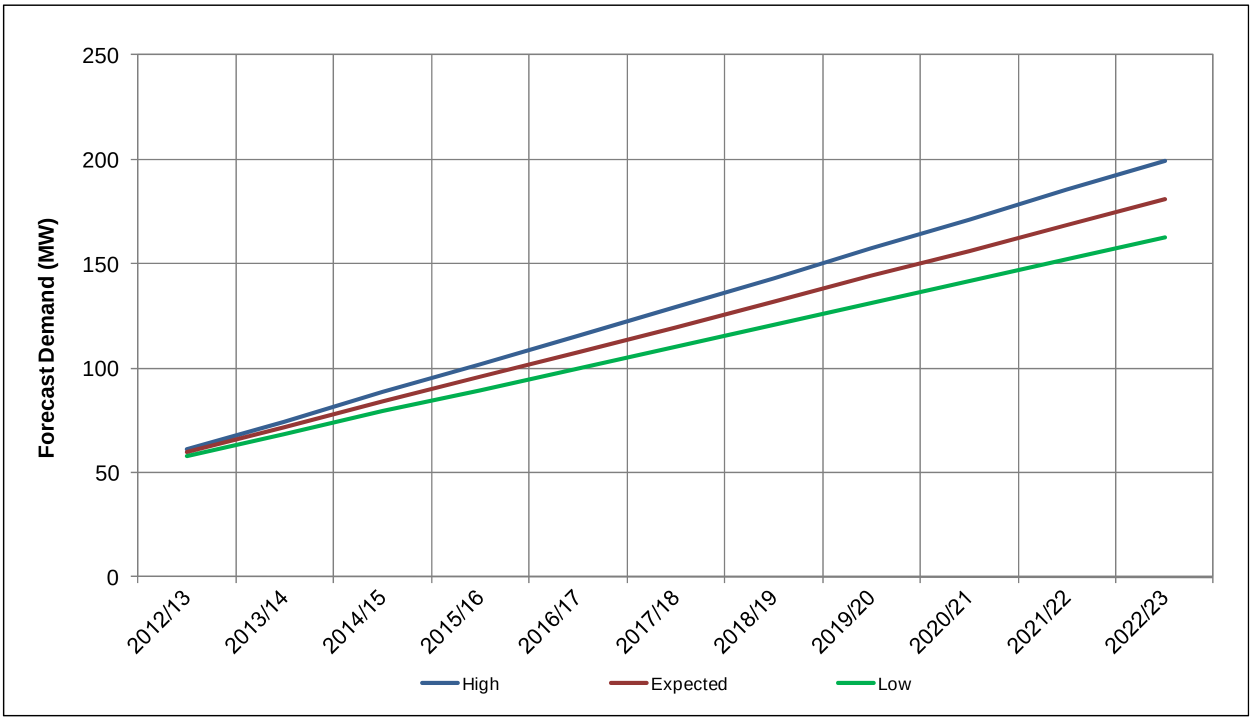
Small-scale PV generation is not separately measurable by the IMO and is observed as reduced consumption. Consequently, these systems are expected to reduce the future requirement for generation and DSM capacity from registered facilities.

NIEIR has incorporated forecasts of small-scale solar PV generation in the demand forecasts for the first time this year. Assumptions have been based on data provided from State owned utilities and NIEIR's experience in similar forecasting assignments in other Australian states.

The Expected growth scenario assumes an installation rate of 2,000 systems per month initially[9] before reducing to 1,750 systems per month as market penetration increases. The average system size is projected to increase across the forecast horizon, from below 2 kW currently to approximately 2.5 kW by 2020.

Figure 25 shows the forecast contribution from small-scale solar PV generation.

Figure 25 – Forecast Contribution to Peak Demand of Small-Scale Solar PV



The IMO notes that changes in government policy and significant movements in the prices of PV systems could lead to a wide range of outcomes. While the recent growth has been dominated by the residential sector, there is the potential for that dominance to shift to the commercial and industrial sectors. This may result in significant increases to the average system size and the total contribution from small-scale PV generation.

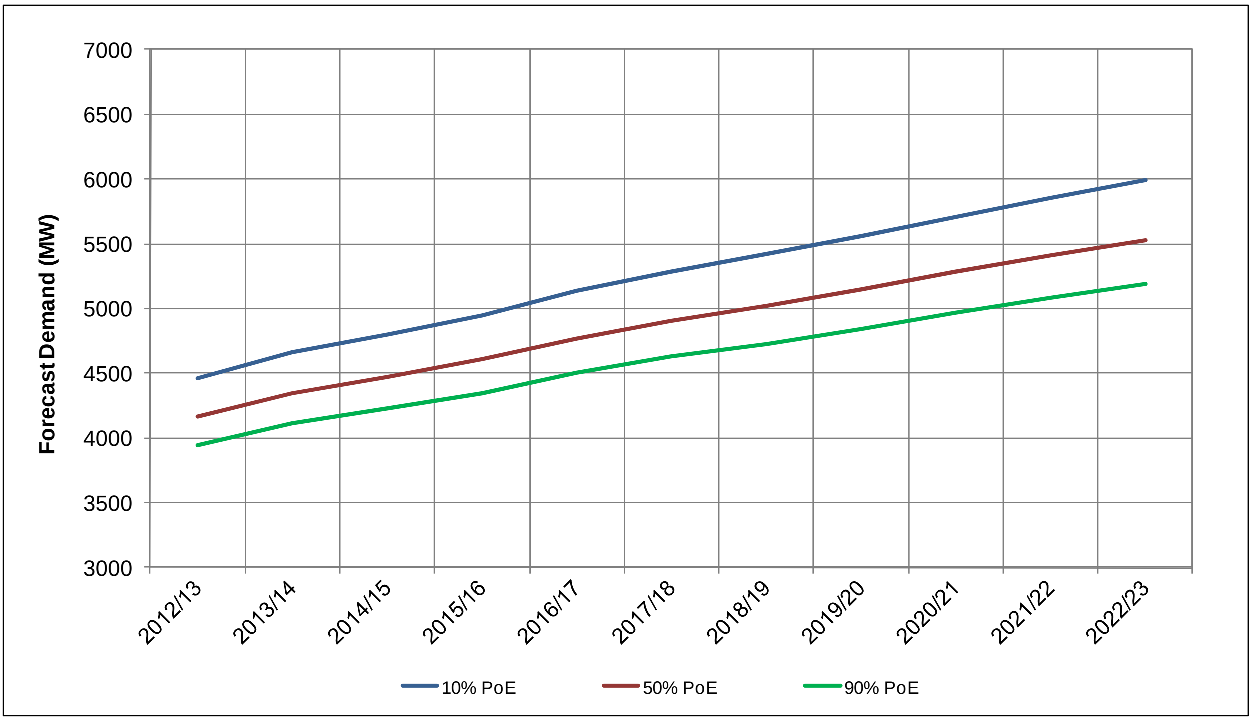
[9] This assumption is consistent with forecasts published by Western Power at http://www.westernpower.com.au/documents/reportspublications/7976363_2011_pv_forecast.pdf

4.6 Maximum Demand Forecasts

NIEIR has forecast that the maximum demand will increase at an annual compound growth rate of 3.0% over the ten-year period from 2011/12 to 2021/22. In 2014/15, the main year of focus in this report, the maximum demand in a 10% PoE scenario is forecast to be 4,804 MW.

Figure 26 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 26 – Forecast Maximum Demand – Expected Economic Growth



The peak demand forecasts include the new block loads identified by the IMO. New block loads have a considerable impact on the rate of growth. Presently the IMO has allowed for approximately 140 MW of additional major block loads through to 2022/23, which represents 3.6% of the 2011/12 summer peak demand.

The sensitivity of maximum demand to temperature can be seen in the differences between the PoE values in Figure 26. For the 2014/15 Capacity Year, if average (50% PoE) temperature conditions are experienced, the maximum demand is forecast to be 6.9% lower (330 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 11.9% lower (573 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 27. The 10% PoE forecasts for the Expected, High and Low economic growth scenarios are shown.

Figure 27 – Impact of Economic Growth on Maximum Demand for the 10% PoE Forecast

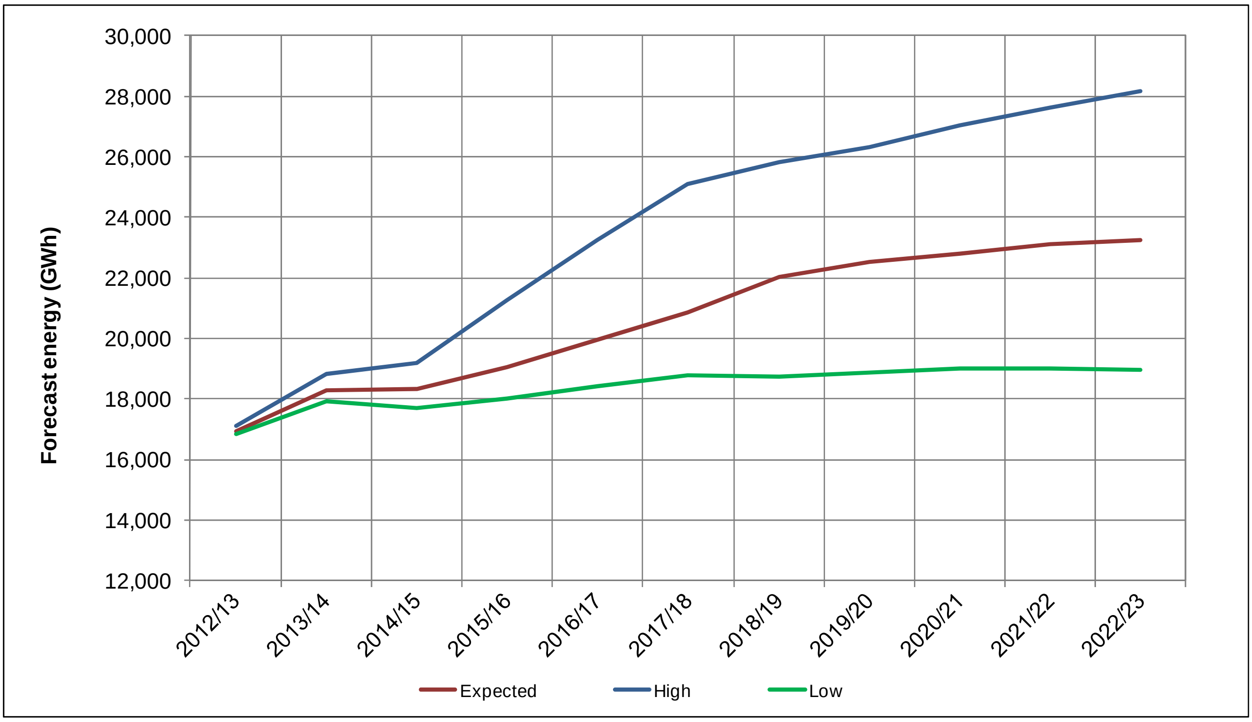
Sensitivity analysis of the economic assumptions on maximum demand shows that if conditions similar to the High economic case are experienced up to 2014/15, the maximum demand is forecast to be approximately 102 MW (2.1%) higher than for the Expected case. Should economic growth be aligned with the Low scenario, the 10% PoE maximum demand is forecast to be approximately 104 MW (2.2%) lower than the Expected case.

4.7 Energy Forecasts

Figure 28 presents the energy consumption forecasts for the SWIS through to 2022/23. Over this period, energy consumption is forecast to grow on average by approximately 2.1% 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 1.0% per annum on average. Approximately one-third of the variation between the High and Low forecasts is caused by different assumptions for new major loads.

Figure 28 – Forecast Sent Out Energy



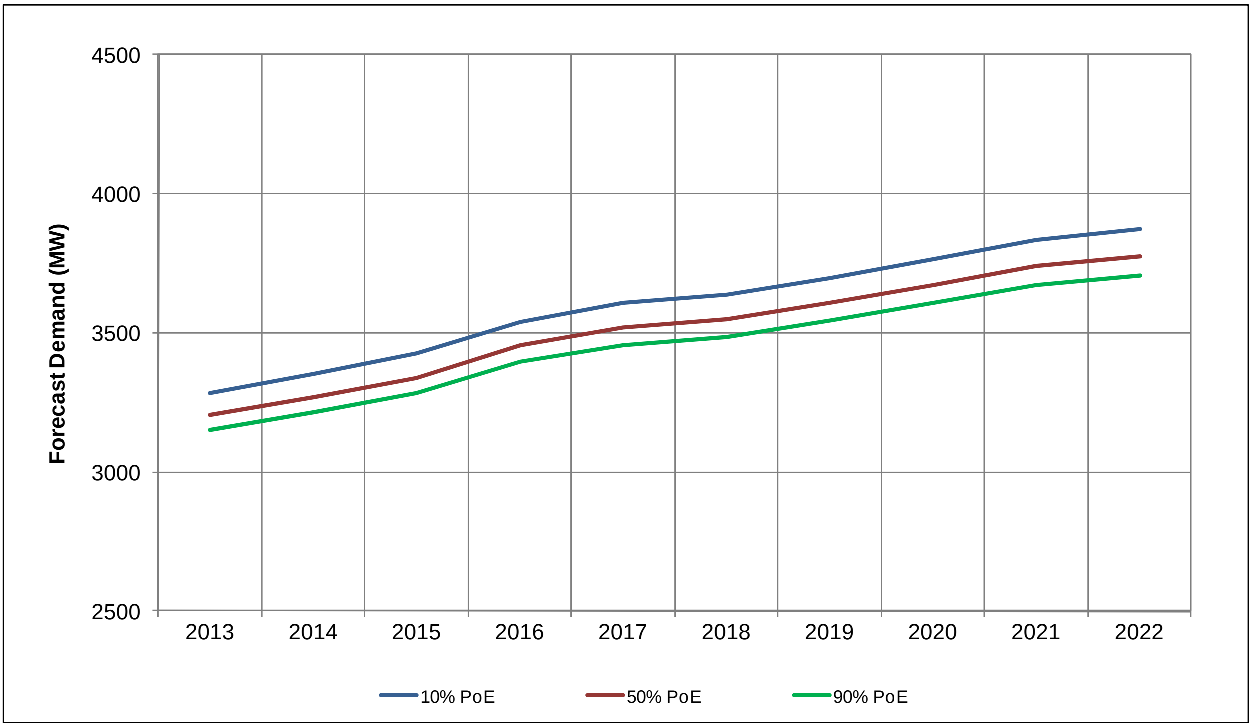
The Expected energy requirements of the SWIS in 2014/15 are forecast to be 18,711 GWh. The energy forecasts are tabulated in Appendix 5.

4.8 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 29, 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 29 – Winter Maximum Demands



Residential and commercial lighting is a significant component of the maximum demand. These, coupled with demand for domestic heating and cooking, cause the winter peak to occur 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 50% PoE winter peak demand is forecast to grow at an average rate of 2.0% to reach a level of 3,740 MW in 2022. This is 68% of the forecast 50% PoE summer maximum demand, reinforcing that the SWIS is a summer peaking system.

4.9 Differences between the 2011 and 2012 Forecasts

The forecasts provided this year for 2014/15 are significantly lower than those presented in the 2011 SOO. A number of significant factors have contributed to the lower peak demand predictions.

- As described in Section 4.4, the IMO has reduced the allowance for new block loads in 2014/15 by 237 MW. This reduction increases to 335 MW from 2017/18 onwards.
- As described in Section 4.5, this year's forecasts incorporate the impact of small-scale PV as a reduction in the future requirement for generation and DSM capacity from

registered facilities. The impact during the summer peak is estimated to be 84 MW in 2014/15, growing to 169 MW by 2021/22.

- A lower level of non-temperature sensitive load has been assumed, reflecting the flat growth in energy sales as described in Section 2.2. This has led to a reduction of approximately 76 MW in 2014/15, growing to 115 MW by 2021/22.

Table 2 compares the 10% PoE maximum demand forecasts prepared in 2011 and 2012.

Table 2 – Comparison of 2011 & 2012 10% PoE Peak Demand Forecasts

Year	2011 10% PoE Forecast (MW)	2012 10% PoE Forecast (MW)	Change in 10% PoE Demand from 2011 to 2012 Forecast (MW)
2012/13	4,635	4,460	-175
2013/14	4,802	4,659	-143
2014/15	5,219	4,804	-415
2015/16	5,448	4,950	-498
2016/17	5,625	5,135	-490
2017/18	5,818	5,290	-528
2018/19	5,978	5,419	-559
2019/20	6,154	5,563	-592
2020/21	6,316	5,711	-605
2021/22	6,481	5,859	-622

The factors listed above have also contributed to lower energy forecasts in the 2012 SOO. The expected energy consumption forecast for 2014/15 of 18,554 GWh is 17.7% below the corresponding forecast in the 2011 SOO of 22,537 GWh. The most significant factors are:

- changes to the forecast for new major loads, which have contributed a reduction of approximately 2,600 GWh (11%)[10]; and
- lower initial levels of residential and commercial demand, reflecting the flat growth in energy sales as described in Section 2.2. The lower starting point results in a reduction of approximately 900 GWh (4%) in 2014/15, two-thirds of which is contributed by solar PV.

4.10 Influences on future electricity consumption

The current rapid rate of technological change in the electricity sector, particularly change that impacts electricity demand management, is having a material influence on Western Australia's load forecasts and has the potential to transform electricity consumption patterns in the coming decades.

[10] This quantity includes a reduction of approximately 300 GWh due to a reduced consumption forecast for a recently completed project for which consumption. As described in Section 4.4, consumption at this project has not reached the level that was initially expected.

Commercial and industrial PV systems

As noted in Section 4.5, the rapid reduction in PV system costs has contributed to the growth in PV installations in over the last 2 years. While the uptake of PV systems at the residential level is expected to continue, there is now the potential for a significant up-take of embedded PV generation in the commercial and industrial sectors.

The sizes of system installation in this sector would be considerably larger than the average residential system size (below 2 kW).

The timing and extent of this growth in commercial and industrial PV installations is currently uncertain. External factors, such as supportive Government policy and the availability of grants[11], and the ability of Western Power to connect these larger systems to the distribution grid cost effectively will impact the pace and scale of this growth.

The impact of smart-grid

Trials conducted by Western Power have also demonstrated the ability to materially impact consumer behaviour and drive energy efficiency through a range of initiatives, some of which are enabled by smart meter technology.

The Perth Solar City trial conducted by Western Power has provided some valuable insights on the impacts of improved information for customers (through methods such as in-home displays), direct load control of air conditioners, time-of-use tariffs, home consultations and behavioural change programs.

The Western Power trial measured the impacts of various measures related to the installation of various smart grid or smart meter technologies. These measures are shown in Table 3.

Table 3 – Reported impact on demand, Perth Solar City trial[12]

Measure	Reported impact
In-Home Displays	6.8% reduction in energy consumption
Living Smart behaviour change program	8.5% reduction in energy consumption
Direct Load Control of air-conditioners	20% reduction at peak time
Time of use tariffs	10.9% reduction at peak time
Home Eco-Consultations	7.8% reduction in energy consumption

If these trial impacts are reflective of what can be achieved across the larger Western Australian electricity consumers base then these impacts will materially transform electricity consumption in the SWIS.

[11] For example, the Clean Technology Program (http://ausindustry.gov.au/programs/CleanTechnology/Pages/default.aspx) provides grants to qualifying businesses to support clean technology and energy efficiency measures, which may include the installation of PV systems.
[12] Data sourced from Perth Solar City, Annual Report 2011, available at http://www.perthsolarcity.com.au/annual-report/

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[13] 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[14] 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 4, 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 2013/14 were developed following consultation with System Management.
- The values from 2014/15 onwards have been set so as to increase by 5 MW per year. The IMO notes that the introduction of a large Intermittent Generator could result in a larger increase in the requirement within a year, though the size and timing of future

[13] Clause 4.5.9(a) of the Wholesale Electricity Market Rules
[14] Clause 4.5.9(b) of the Wholesale Electricity Market Rules

Intermittent Generator projects is uncertain. These values have been reduced since last year.

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. This review is currently being undertaken by the IMO and is expected to be completed in late 2012.

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 capacity to accommodate this required maintenance throughout the year. This year, the IMO has appointed PA Consulting 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 provided 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, such as the commencement of 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 2014/15 Capacity Year, the peak demand-based capacity requirement exceeds the energy-based requirement by more than 700 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 appears to be reducing and plant availability remains high during the summer months, as reported in section 2.5.4.

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

Table 4 – 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
2012/13	4,460	366	90	15	4,931
2013/14	4,659	382	90	15	5,146
2014/15	4,804	394	95	15	5,308
2015/16	4,950	406	100	16	5,472
2016/17	5,135	421	105	16	5,677
2017/18	5,290	434	110	16	5,850
2018/19	5,419	444	115	16	5,994
2019/20	5,563	456	120	17	6,156
2020/21	5,711	468	125	17	6,321
2021/22	5,859	480	130	17	6,486
2022/23	5,990	491	135	17	6,633

The figure of 5,308 MW, as shown in Table 4, is therefore the Reserve Capacity Requirement for the 2012 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, 2014/15 and 2015/16 is shown in Table 5.

Table 5 – Availability Curve

Availability Curve Information	2013/14 (MW)	2014/15 (MW)	2015/16 (MW)
Market Rule 4.5.12(a):			
Capacity required for more than 24 Hours	4,469	4,605	4,741
Capacity required for more than 48 Hours	4,300	4,429	4,561
Capacity required for more than 72 Hours	4,188	4,314	4,441
Market Rule 4.5.12(b):			
Minimum Generation Required	4,281	4,438	4,592
Market Rule 4.5.12(c):			
Capacity associated with Availability Class 1	4,281	4,438	4,592
Capacity associated with Availability Class 2	19	0	0
Capacity associated with Availability Class 3	169	167	150
Capacity associated with Availability Class 4	677	703	731

Due to the complexity of the Availability Curve determination, the IMO has provided a more detailed explanation and graphs of the capacity requirements in Appendix 8. As is noted in the explanation, the method for determining the Availability Curve has evolved since last year. In particular, the treatment of the reserve margin and the availability restrictions of DSP's have the effect of increasing the capacity associated with Availability Class 1 (i.e. generation).

However, this year's demand forecasts predict a lower load factor compared to last year, driven by the changes to new block load forecasts, solar PV and a lower level of non-temperature sensitive load (reflecting the flat growth in energy sales as described in Section 2.2). This has the effect of reducing the capacity associated with Availability Class 1.

Consequently, the total capacity associated with Availability Classes 2, 3 and 4 (i.e. DSM) is similar to the values presented in the 2011 SOO, albeit with a shift towards the higher Availability Classes as a result of Rule Change RC_2011_14[15].

The Availability Curve does not limit the amount of Capacity Credits assigned to any Availability Class where there is intent to bilaterally trade. The quantities shown are not expected to be binding in the 2014/15 and 2015/16 Capacity Years.

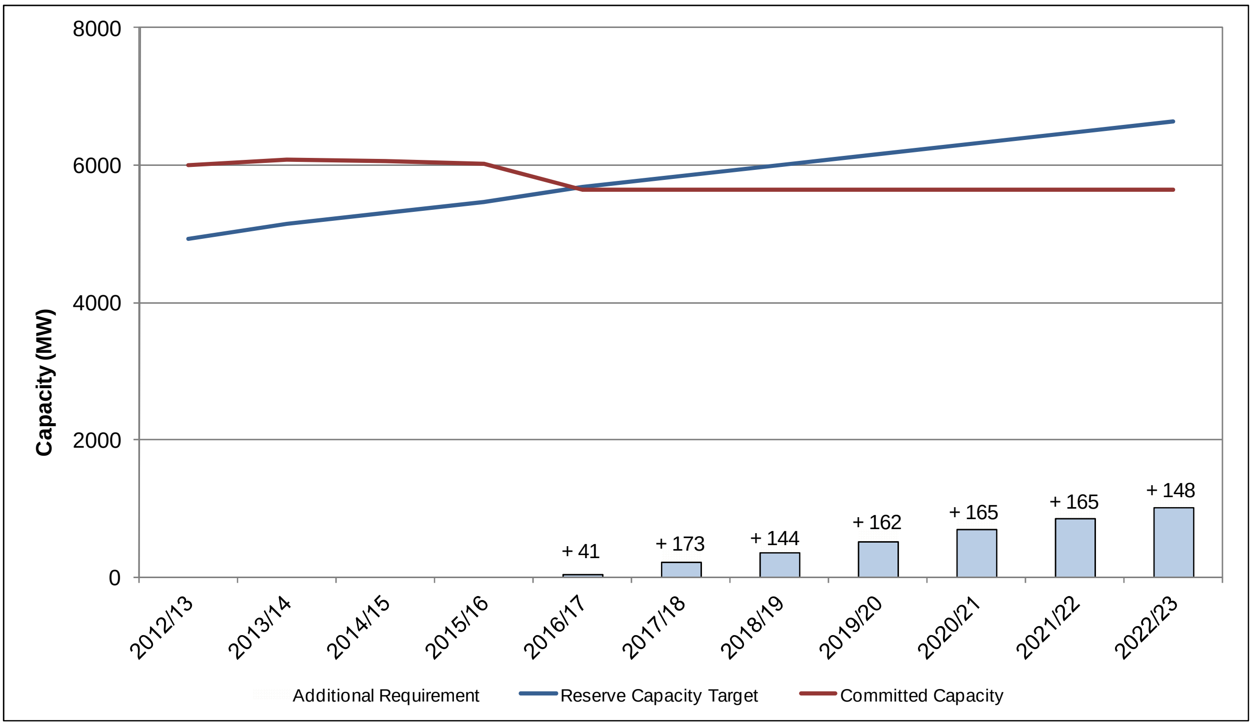
[15] More information on the Rule Change is available at http://www.imowa.com.au/rc_2011_14.

5.5 The Supply-Demand Balance

The supply-demand balance for the period to 2022/23 in the SWIS is presented in Figure 30.

- The blue line in this figure shows the Reserve Capacity Target, increasing from 4,931 MW in 2012/13 to 6,633 MW by 2022/23.
- The red line shows the level of generation and DSM capacity which is in place or committed.
    - For the 2012/13 and 2013/14 Capacity Years, the level of capacity is set by the assigned Capacity Credits. The increase in capacity from 2012/13 to 2013/14 represents the continued commitment of new facilities made in the 2011 Reserve Capacity Cycle.
    - For subsequent years, the level of capacity that is currently in service or committed is assumed to reduce from the levels shown in Appendix 9. The IMO has forecast a reduction over three years from 2014/15 to 2016/17 due to the likely reduction in Capacity Credits for Intermittent Generators following the implementation of Rule Change RC_2010_25. In addition, the IMO has anticipated the decommissioning of Verve Energy's Kwinana Stage C facilities (361.5 MW) for the 2016/17 Capacity Year, 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 30 – Required Generation and DSM Capacity



Key points to note from Figure 30 are:

- Sufficient Capacity Credits have been procured to meet the Reserve Capacity Requirement through to 2015/16.
- In-service and committed facilities, prior to the introduction of any new capacity, will provide surplus capacity of 749 MW in 2014/15.
- A further 998 MW of Capacity Credits will be needed to meet the increase in the Reserve Capacity Target from 2014/15 to 2022/23 after accounting for the likely retirement of Kwinana Stage C (361.5 MW).

This figure illustrates the opportunities, in the longer term, for investment in generation and DSM capacity in Western Australia. Almost 1,000 MW of new capacity is forecast to be required in the latter half of 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 2022/23. Project proponents, investors and developers should 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 5,308 MW and 5,472 MW of generation and DSM capacity must be available to meet the Reserve Capacity Requirements in 2014/15 and 2015/16 respectively.

It is estimated that capacity already in place or under construction will provide an excess of 749 MW of capacity in 2014/15 and 555 MW in 2015/16, prior to the introduction of any new capacity. 41 MW of new capacity will be required by 2016/17 in order to satisfy the requirement for that year. This is summarised in Table 6.

Table 6 – Opportunity for Investment

	2014/15	2015/16
Existing Capacity	5,284 MW	5,284 MW
Committed Generation and DSM Committed	803 MW	803 MW
Estimated Capacity Credit reductions[16]	30 MW	60 MW
Reserve Capacity Requirement	5,308 MW	5,472 MW
Surplus Capacity	749 MW	555 MW

The most recent Expressions of Interest process identified proposals for 213.7 MW of new Reserve Capacity for the 2014/15 Capacity Year. It should be noted, however, that the

[16] These figures represent a preliminary estimate of the potential reduction in Capacity Credits for Intermittent Generators following the commencement of Rule change RC_2010_25, which was implemented with a three-year transition. The actual reductions, which will be calculated by the IMO when determining Certified Reserve Capacity, may differ from these values.

proponents of these developments have not necessarily indicated any level of commitment to proceed.

While the Expression of Interest process provides an indication of potential future capacity, the submission of an Expression of Interest does not necessarily translate into certified capacity. In 2011, Expressions of Interest were received for 337 MW of new capacity but only 42 MW of this capacity was assigned Capacity Credits for the 2013/14 Capacity Year.

The IMO has analysed the Expressions of Interest 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 67 MW of available Capacity Credits in 2014/15 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 31 and Figure 32. In these figures "Proposed Projects" relates to the 67 MW of planned projects identified above as "potential".

As these graphs and Figure 30 show, existing and committed capacity is more than sufficient to meet the capacity requirements of the SWIS beyond the middle of this decade. Consequently, there is limited opportunity for new investment in the near term.

Figure 31 – Opportunity for Investment – 2014/15

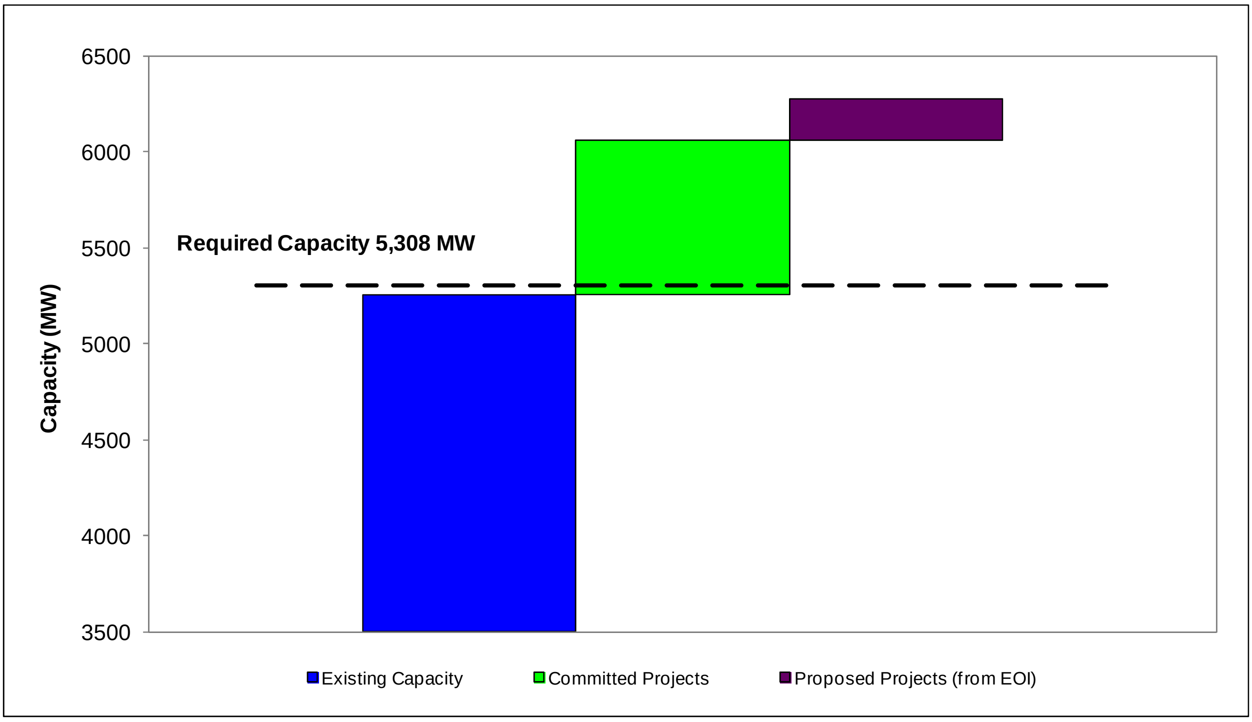
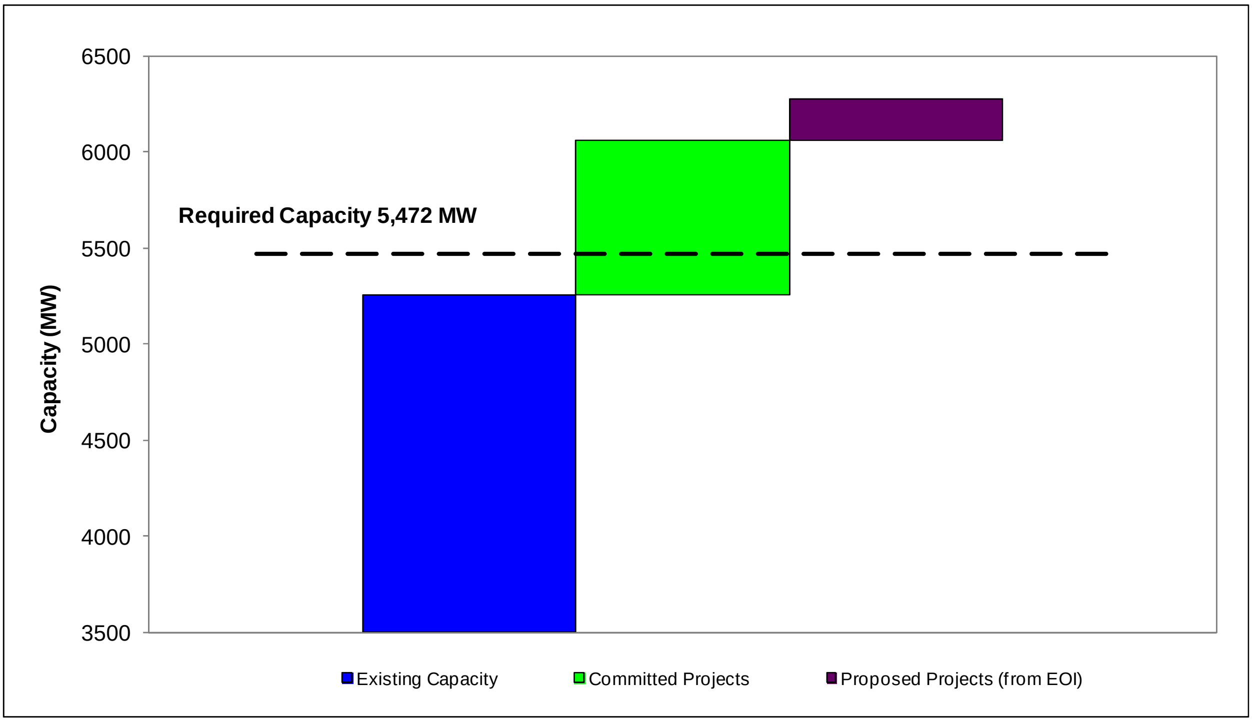


Figure 32 – Opportunity for Investment – 2015/16



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.

The timetable for the 2012 certification process is as follows:

- Applications for certification of Reserve Capacity are now open and must be provided to the IMO by 5:00 PM WST on Friday, 29 June 2012.
- By 5:00 PM on Friday 17 August 2012 the IMO must advise each applicant of the Certified Reserve Capacity to be assigned for the 2014/15 Capacity Year.
- Market Participants with facilities that are granted Certified Reserve Capacity must then indicate whether they intend to trade capacity bilaterally or 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, 31 August 2012.
- On Monday 3 September 2012, the IMO will advise Market Participants who have indicated their intention to trade their capacity bilaterally as to how many Capacity Credits will be assigned to their facilities.
- By 5:00 PM on Tuesday 4 September 2012, 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 5 September and Friday 14 September 2012. The IMO would run the Reserve Capacity Auction on Monday 17 September 2012.

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.

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[17], and the procedure for Declaration of Bilateral Trades and the Reserve Capacity Auction[18], are available on the IMO website.

[17] http://www.imowa.com.au/crc
[18] 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 was required to deal with emerging issues in the energy industry.

The Strategic Energy Initiative was intended to develop:

- an energy vision for 2031, including a range of demand scenarios and potential supply options;
- a set of clear goals to guide decisions by policy makers and investors;
- a range of flexible strategies to allow industry and the community to adapt to emerging opportunities and challenges; and
- a policy and regulatory framework to promote investment and competitiveness and remove barriers to technological change.

An Issues Paper was released in December 2009 and was followed by a public consultation process. The Office of Energy then published the *Energy2031* Strategic Energy Initiative Directions Paper in March 2011. The public consultation process following the release of the Directions Paper closed on 6 May 2011.

A final paper had been scheduled for release in mid-2011. However, it has yet to be published and no updated timing has been provided.

More information on the SEI can be found on the Public Utilities Office website[19].

7.2 Network Transmission Restrictions on the SWIS

To assist potential developers, Western Power, in collaboration with the Department of Planning and the Western Australian Planning Commission, has prepared a geospatial map viewer called the Network Capacity Mapping Tool (NCMT)[20].

The NCMT is an information service that is available to all external parties. It provides access to some of Western Power's electricity network planning information, including a 20 year outlook of the annual forecast remaining capacity available at Western Power zone substations. This enables the customer to view Western Power's current and proposed electrical network and understand how it may affect their development plans and investment options.

As is indicated in the NCMT, the transmission system is nearing capacity in several locations. Western Power advises that this is due to the increase in overall electricity demand, requests for connections for new generators and to accommodate differing energy flows across the system.

[19] http://www.finance.wa.gov.au/cms/content.aspx?id=13638
[20] http://www.westernpower.com.au/ldd/ncmtoverview.html

Consequently, as noted in its Annual Planning Report[21], Western Power is planning a range of transmission augmentations to alleviate constraints.

The most significant new project underway is the Mid West Energy Project (MWEP) (Southern Section) 330 kV double circuit transmission line from Neerabup to Eneabba. This project is expected to facilitate the connection of new generation and additional load.

Western Power has provided the IMO with the following information in relation to the MWEP (Southern Section) as at 13 June 2012:

- The project will provide a double circuit 330 kV line (initially operated as one 330 kV and one 132 kV circuit) from Neerabup to Eneabba where it will connect to a 330 kV line already constructed to provide an initial supply to the Karara mining load. A 330/132 kV terminal station will also be established at Three Springs.
- Regulatory assessment of the MWEP was finalised in January 2012 when the ERA determined that the project satisfied the New Facilities Investment Test.
- Funding for the project has been secured from the State Government[22] and Western Power is in the process of obtaining final approval from the State Government to execute a contract with a line construction contractor. Western Power expects to execute the contract by the end of June 2012, with line construction and related works expected to commence in October 2012.
- Western Power has undertaken considerable preparatory works in advance of full approval, including line corridor selection and preparation and environmental approvals.
- The 330 kV line is scheduled to be energised in June 2014, with remaining works (including 132 kV connection to Three Springs 132/33 kV Substation via Three Springs 330/132 kV Terminal Station) to be completed by August 2014. However, Western Power notes that this timeline is subject to execution of the line construction contract by the end of June 2012, and indicates that the major threat to the timeline is prolonged adverse weather conditions.
- Western Power is now able to consider connection applications from generators wishing to connect to the transmission network in the Mid West region south of Three Springs, but notes that the connection of a generator may trigger the need to reconfigure the network to allow operation of both circuits of the new line at 330 kV.

Transmission access is a key determinant in assessing the eligibility of new capacity for Reserve Capacity Certification. 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.

[21] Available at http://www.westernpower.com.au/aboutus/publications/2011apr/index.html.
[22] Ministerial media statement, 18 May 2012, "*State Budget 2012/13: Building the State – Government to power up Mid-West*", available at http://www.mediastatements.wa.gov.au/Pages/WACabinetMinistersSearch.aspx?ItemId=150110&minister=Collier&admin=Barnett

To be certified in the 2012 Reserve Capacity Cycle, a new facility must be capable of fully meeting its Reserve Capacity obligations by 1 October 2014. Thus, proponents must provide evidence that firm access will be available prior to that date.

Given the information provided by Western Power, including the risks to the project schedule, and the expectation that additional works would be required to connect a generator that is reliant on the MWEP, the IMO does not consider it likely that such a generator could be granted firm access by 1 October 2014.

Consequently, the IMO will be unable to assign Certified Reserve Capacity for the 2014/15 Capacity Year to any proposed new generators which rely on the new transmission works.

Generation projects reliant on the MWEP (Southern Section) would be able to apply for certification in future years once firm 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. This could result in a lower allocation of Capacity Credits to facilities compared with facilities with unconstrained network access.

In the *Energy2031* Strategic Energy Initiative Directions Paper, the Office of Energy 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).

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 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 process 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 design and implementation of such a model is a significant undertaking, with some previous estimates indicating many years of development as well as dedicated staff required for ongoing maintenance. A 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.

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 of implementation time.

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.

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

7.3 Availability of Fuel for Generation

Capacity in the SWIS is dominated by conventional generation facilities, which burn some form of non-renewable fossil fuel. As was shown in Figure 11, about 50% of Capacity Credits for the 2013/14 Capacity Year are allocated to gas fuelled plants or gas-liquids dual fuelled plant. Coal and dual fuelled coal-gas/liquids plant account for a further 35% 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 as base-load capacity. Mid-merit operations are typically performed by gas-fired plant, though some cycling of coal-fired plant overnight has been required. Peak-load plants are dominated by gas, dual-fuelled gas-liquids and liquids plant.

Figure 33 – Proportion of Total SWIS Generation by Fuel Type, 2011

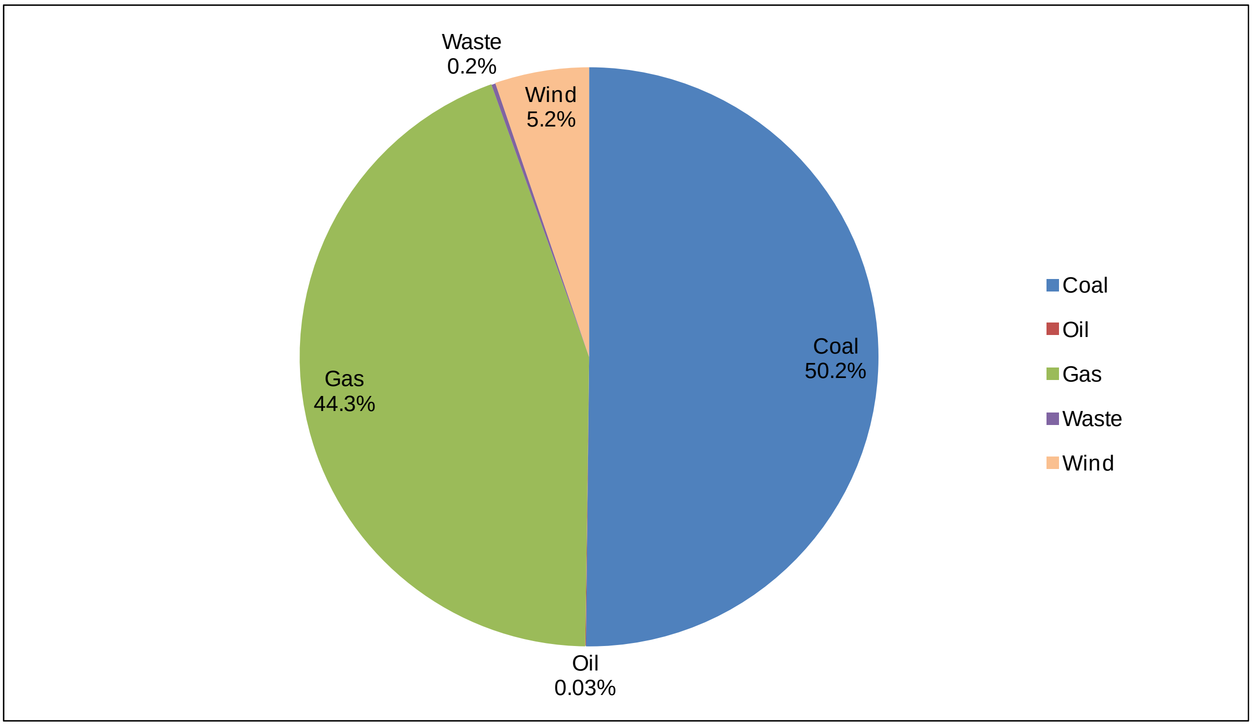


Figure 33 indicates the total sent out electricity in the SWIS by fuel type[23]. As can be seen, about 50% of the total energy produced was from coal, gas accounts for 44% while renewable resources (wind and landfill gas) contributed around 5.5% of the total generation. As shown in the chart, the proportion of energy generated from liquids is very small as dispatch of these facilities is extremely rare. Operation of liquid-fuelled plant in 2011 was predominantly for commissioning and compliance testing purposes.

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: Premier Coal (purchased by Yancoal Australia in 2011) and Griffin Coal (purchased by Lanco Infratech Limited in December 2010). 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.

[23] Data aggregated from individual facility data. For gas-liquid dual-fuel generation facilities, gas has been assumed. For coal-gas dual-fuel generation facilities, energy has been allocated equally to coal and gas based on advice from Verve Energy. Embedded generation, including small-scale solar PV generation, is not included.

For the 2011 calendar year, Western Australia's coal production was close to 7 million tonnes[24]. The vast majority of this is consumed within Western Australia, with almost 80% of that consumption being for power generation[25]. All Western Australian coal-fired power generation is located in the SWIS, mostly adjacent to or very close to the producing coal mines. In 2010-11, some 1.1 million tonnes of coal was exported[26] with the remainder of Western Australia's consumption occurring in manufacturing and mineral processing.

The two coal mine operators have indicated that substantial coal resources remain. Premier Coal has indicated resources of 535 million tonnes with an estimated reserve (proved and probable) of 138 million tonnes[27], while Lanco has estimated resources of 1.1 billion tonnes[28]. Some of these reserves will be committed under long term contracts, while Lanco in particular has indicated its commitment to expansion of exports from Griffin Coal[29].

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. In February 2012, the Devil Creek Gas Plant added to this diversity, which is expected to expand further in 2013 by the Macedon Project[30].

Domestic gas (domgas) consumption in Western Australia has grown significantly from about 100 terajoules per day (TJ/d) in 1984, when gas from the north west of the state was introduced, to around 1,000 TJ/d in 2011.

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 lists the gas-fired generation facilities commissioned since 2000.

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[24] http://www.dmp.wa.gov.au/1525.aspx
[25] *Australian Energy Statistics - Energy Update 2011*, Bureau of Resources and Energy Economics (BREE), Table F5, http://bree.gov.au/data/energy/AES-2011.html
[26] *Fremantle Ports 2011 Annual Report*
[27] *Page 7, Wesfarmers Annual Report 2011,* http://www.wesfarmersinsurance.com.au/Documents/wes_ar11_asx_220911.pdf
[28] *Lanco Infratech Limited, Annual Report 2010-11*
[29] http://lancogroup.com/DynTestform.aspx?pageid=45
[30] http://www.dmp.wa.gov.au/documents/StatsDigest1011.pdf

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	2012	200

Several gas developments, namely Macedon, Gorgon and Wheatstone are anticipated to supplement the existing domgas production in the coming years. Figure 34 summarises the existing, committed and announced potential domgas processing capacity in Western Australia.

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 from 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 8, accompanied by a detailed summary of available information related to current and future domestic gas production and processing capacity.

Figure 34 – Existing, Committed and Potential WA Domgas Processing Capacity

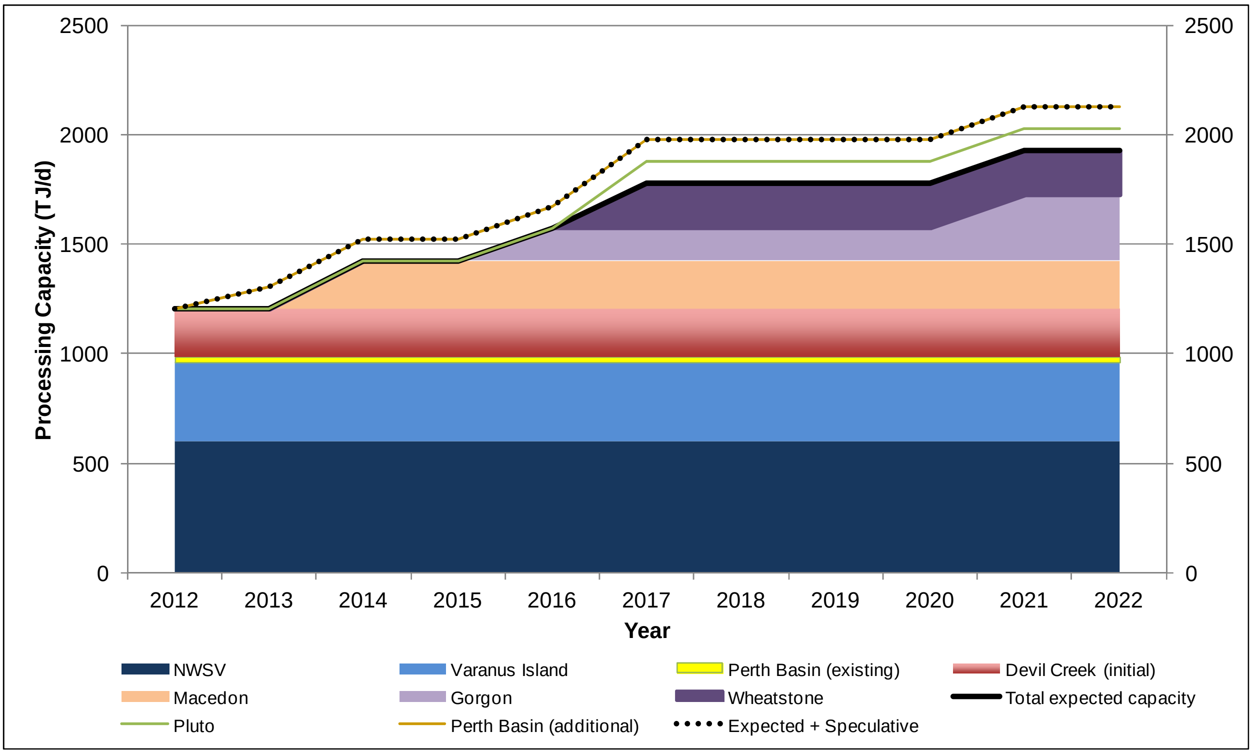

Table 8 – Summary of Available Information Related to Current and Future Domestic Gas Production and Processing Capacity

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
• Current domgas processing capacity around 600 TJ/d. *Source: Woodside Website*[31]	
• 2011 average output was approximately 575 TJ/d. *Sources: Woodside, Second Quarter Report, 2011*[32] *and Woodside, Fourth Quarter Report, 2011*[33]	
• The original domgas obligation for the project is anticipated to be satisfied by the end of 2013. *Source: ACCC website,* "North West Shelf – Authorisations – A91220	

[31] http://www.woodside.com.au/our-business/north-west-shelf/onshore-production-facility/productionfacilities/pages/production-facilities.aspx

[32] http://www.woodside.com.au/Investors-Media/Announcements/Documents/19.07.2011%20Second%20Quarter%202011%20Report.pdf

[33] http://www.woodside.com.au/Investors-Media/Announcements/Documents/21.01.2011%20Q4%202010%20Quarterly%20Report.pdf

– A91223*", Application Attachment 1 ("*Western Australia Gas Market Study*")*[34].	utilisation of existing facilities.
• North Rankin redevelopment is underway and the Greater Western Flank development has been approved, with expected completion dates of 2013 and 2016 respectively. Both developments are anticipated to enable production to be maintained "beyond 2020". *Source: Woodside 2011 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, 2011 production around 355 TJ/d. *Sources: Speech by Premier Colin Barnett to Baker Institute, 13 Apr 2010[35]; Apache Corporation website[36].*	
• Future production of the Halyard & Spar fields expected to sustain domgas production in the coming years. • Halyard commenced production in June 2011, with Spar expected to be online in 2013. *Source: Santos website[37].*	
Devil Creek	
• Operated by Apache, all gas for domestic use.	The IMO considers that production 120 TJ/d could be maintained for at least 10 years. Timing of an increase in production to 215 TJ/d is uncertain, and will likely be driven by customer demand and connection of additional gas fields.
• Plant operational since December 2011 with production capacity of 220 TJ/d. • Production initially expected to ramp up to 110 TJ/day. *Source: Project Fact Sheet, Devil Creek Domestic Gas Project[38].*	
• 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.*	

[34] *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.
[35] http://www.mediastatements.wa.gov.au/Pages/default.aspx?ItemId=133337&
[36] Apache share of production (55%) of 185 Mcfd from http://www.apachecorp.com/Operations/Australia/Region_overview/index.aspx, conversion factor of 1.06 TJ/ Mcfd from http://www.santos.com/conversion-calculator.aspx.
[37] http://www.santos.com/exploration-acreage/production-processing/spar.aspx
[38] http://www.apachecorp.com/Resources/Upload/file/AEL/Devil_Creek_Fact_Sheet_201202.pdf

<table>
<tr><td colspan="2">Macedon</td></tr>
<tr><td>• 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. 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”.</td><td rowspan="3">The IMO expects gas production in 2014. The IMO considers that production of 220 TJ/d could be sustained for 7-10 years. Production levels after this time may depend on field performance and the connection of other gas fields.</td></tr>
<tr><td>• 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[39].</td></tr>
<tr><td>• 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[40].</td></tr>
<tr><td colspan="2">Gorgon</td></tr>
<tr><td>• LNG project, operated by Chevron. Construction underway.</td><td rowspan="5">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.

• The Gorgon Project is due to deliver domestic gas to the market end of 2015 or at the time of first LNG production from the third train, whichever is earlier.
Source: Department of State Development website[41].</td></tr>
<tr><td>• Verve and Synergy have entered into contracts for a combined 125 TJ/d for 20 years, starting in 2015.
Source: Chevron press release, 30 November 2011, “Chevron Secures Gorgon Domestic Gas Sales Contracts”[42].</td></tr>
<tr><td>• The domestic gas plant is expected to progressively supply up to 300 TJ/d.
Source: Chevron website[43].

• “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”.</td></tr>
</table>

[39] http://files.shareholder.com/downloads/APA/1282234980x0x469895/6c5e8d07-a5ec-4cdf-8f75-43a293236bbb/Apache_InvestorDay_20110517-06-Australia.pdf
[40] Available from http://www.epa.wa.gov.au/EIA/prop/Pages/3221_EPS-MacedonGasDevelopment.aspx?pageID=76&url=EIA/prop
[41] http://www.dsd.wa.gov.au/7599.aspx
[42] http://www.chevronaustralia.com/media/mediastatements.aspx?NewsItem=28486d1c-f2a8-4109-97f5-c731fd0520d0
[43] http://www.chevronaustralia.com/ourbusinesses/gorgon/downstream.aspx

<table>
<tr><td>Source: The West Australian, 16 June 2009, “Barnett opens door to gas reserve changes”, published in Domgas Alliance submission to Strategic Energy Initiative[44].</td><td></td></tr>
<tr><td colspan="2">Wheatstone</td></tr>
<tr><td>• LNG project, operated by Chevron. Construction underway.</td><td rowspan="2">The IMO considers that the domestic gas plant will be available by 2017, with a capacity of 200 TJ/d.</td></tr>
<tr><td>• First domestic gas production is estimated in 2016. Estimated domgas capacity of 200 TJ/d.
Source: Chevron website[45].</td></tr>
<tr><td colspan="2">Pluto</td></tr>
<tr><td>• Single train LNG project, operated by Woodside. Woodside continues to pursue expansion plans.
• LNG production commenced April 2012, with forecast production capacity of 4.3 million tonnes per annum (Mtpa).
• 15-year LNG sales agreements in place with Kansai Electric and Tokyo Gas.
Source: Woodside Press Release[46] and website[47]</td><td rowspan="3">The IMO considers that around 100 TJ/d could become available during 2017. In the absence of confirmation to develop a domestic gas plant, the IMO has classified this capacity as speculative.</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 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[48].</td></tr>
</table>

[44] 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

[45] http://www.chevronaustralia.com/media/mediastatements.aspx?NewsItem=e84ba4ad-bdc6-4d90-ad3d-177af7a69cab and http://www.chevronaustralia.com/ourbusinesses/wheatstone/downstream.aspx

[46] http://www.woodside.com.au/Investors-Media/Announcements/Documents/30.04.2012%20Pluto%20Begins%20LNG%20Production.pdf

[47] http://www.woodside.com.au/Our-Business/Pluto/Pages/default.aspx

[48] http://www.climatechange.gov.au/publications/projections/~/media/publications/projections/acil-tasman-stationary-energy-modelling-pdf.pdf

Perth Basin	
• Alcoa and Transerv Energy pursuing development of Warro tight gas field in Perth Basin. Target production from the field is 100 TJ/d. Transerv is the operator. *Source: PetroleumNews.net, 7 May 2010,* "Latent likes chances of tight gas success."[49]	Due to technological challenges, the IMO has classified the Warro project and shale gas production as speculative at this stage. Existing Perth Basin production is expected to remain relatively constant.
• AWE is planning evaluation of shale gas reserves in the Perth Basin. This work is scheduled to commence in June/July 2012.[50].	

7.3.3 Gas Transportation

Gas is transported into the SWIS via three routes:

- Dampier to Bunbury Natural Gas Pipeline (DBNGP), which receives gas from the KGP, Varanus Island and Devil Creek facilities, and will receive gas from other new offshore developments when they are commissioned, such as Macedon, Gorgon and Wheatstone;
- 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%[51]. 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[52], 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.

[49] http://www.petroleumnews.net/storyview.asp?storyid=1135396&sectionsource=s90&highlight=latent
[50] http://www.awexp.com.au/IRM/Company/ShowPage.aspx/PDFs/2604-40127605/AWEsJune2012Presentation
[51] Discussions with DBP Transmission
[52] Discussions with DBP Transmission

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 Pilbara (through the DBNGP interconnect at Mondarra). The pipeline extends from Dongara, through Perth and Kwinana to Pinjarra, south of Perth[53].

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[54].

7.3.4 Gas Storage

Gas storage capacity can enhance the security of gas supply, lessening the impact of upstream gas supply disruptions and reducing the pressure on liquid fuel supplies. 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.

APA Group has recently committed to an expansion of its commercial underground gas storage facility at Mondarra[55], which is connected to both the Parmelia Gas Pipeline and the DBNGP. 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 to 15 PJ, more than five times its current level. 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"[56].

7.3.5 Gas Information Services Project (GISP)

The Gas Information Services Project (GISP) is being undertaken by the IMO, comprising a Gas Bulletin Board (GBB) and Gas Statement of Opportunities (GSOO). These initiatives will bring greater transparency to the natural gas market in Western Australia.

The objectives of the GBB and GSOO are to promote the long term interests of consumers of natural gas in relation to:

- the security, reliability and availability of the supply of natural gas in the State;

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[53] Provided by APA Group
[54] Provided by APA Group
[55] http://www.openbriefing.com.au/AsxDownload.aspx?pdfUrl=Report%2FComNews%2F20110526%2F01183952.pdf and http://www.mediastatements.wa.gov.au/Pages/default.aspx?ItemId=140541&page=2.
[56] http://www.mediastatements.wa.gov.au/Pages/default.aspx?ItemId=140541&page=2

- the efficient operation and use of natural gas services in the State;
- the efficient investment in natural gas services in the State; and
- the facilitation of competition in the use of natural gas services in the State.

The GBB will consist of a website to publish information about short and near term natural gas supply, transmission, storage and demand in Western Australia. The GBB will also provide an emergency management page to assist in the management of supply disruptions. It may also include information about other fuels, and later could be developed into a platform to facilitate the introduction of buyers and sellers of gas.

The GSOO will be an annual planning document providing a comprehensive medium to long term outlook of gas supply and demand in Western Australia, highlighting potential shortfalls or constraints.

The timing of the project is subject to the implementation of the first stage of the Gas Services Information Regulations 2012 and the approval of funding for the IMO. Assuming that these requirements are met by July 2012, the GBB is scheduled to go live and the first GSOO is scheduled to be published in mid-2013.

7.3.6 Liquid Fuel

Diesel is the dominant liquid fuel used for power generation in the SWIS. Generators typically 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 10-15 days consumption[57], 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. As noted in its submission to the Directions Paper[58], the IMO has previously recommended a design concept to the Office of Energy. The IMO has since followed up with the then Office of Energy and, since its establishment, the Public Utilities Office and is awaiting feedback. The

[57] *Maintaining Supply Reliability in Australia*, Australian Institute of Petroleum, April 2008
[58] http://www.finance.wa.gov.au/cms/uploadedFiles/Public_Utilities_Office/WAs_Energy_Future/Independent%20Market%20Operator.pdf

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 Commonwealth 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 various schemes and their eligibility for any associated funding.

- The Commonwealth Government's carbon pricing mechanism commences operation on 1 July 2012, with a transition to a cap-and-trade emissions trading scheme after three to five years. Further information is available from the Department of Climate Change and Energy Efficiency[59].
- In addition to the carbon pricing mechanism, the Commonwealth Government has a range of additional programs and initiatives within its Clean Energy Future package. Details of these are available from the Clean Energy Future website[60].
- The Commonwealth 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. The RET is split into two parts: the Large-scale Renewable Energy Target (LRET) and the Small-scale Renewable Energy Scheme (SRES). Large-scale renewable energy generators receive incentives in the form of Large-scale Generation

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[59] http://www.cleanenergyfuture.gov.au/clean-energy-future/carbon-price/
[60] http://www.cleanenergyfuture.gov.au/clean-energy-future/programs-and-initiatives/

Certificates (LGCs) that can be traded. Further information is available from the Clean Energy Regulator[61].

- The State Government's Low Emissions Energy Development (LEED) Fund has been established to support the development of low-emission electricity generation technology. Further information is available from the Department of Environment and Conservation[62].

7.7 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.

Since the final meeting of the REGWG was held on the 2 September 2010, one rule change has commenced and another proposal is under review:

- Rule Change Proposal, RC_2010_25[63] has amended the method for calculating Certified Reserve Capacity Credits for Intermittent Generators. The new methodology, which will be employed for the first time in 2012, assigns Capacity Credits based on the expected output of the Intermittent Generator during periods of highest system stress and incorporates an adjustment for the variability of the Intermittent Generator. This new methodology is expected to be beneficial for developers of solar generation, but may result in a reduction in Capacity Credit allocations for some Intermittent Generators, such as wind farms. A three-year transition path has been incorporated into the Market Rules.
- A pre-rule change discussion paper (PRC_2010_27) 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 IMO expects to progress PRC_2010_27 into the rule change process following the implementation of the new LFAS Market in July 2012.

Parties considering development of Intermittent Generators should familiarise themselves with the details of the Rule Change proposals and the potential impact on new facilities.

7.8 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 (MRCP).

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61 http://www.cleanenergyregulator.gov.au/Renewable-Energy-Target/Pages/default.aspx
62 http://www.dec.wa.gov.au/content/view/6499/2369/
63 http://www.imowa.com.au/RC_2010_25

The MAC convened the Maximum Reserve Capacity Price Working Group (MRCPWG) to undertake this review. The MRCPWG completed its review in 2011 and recommended a number of changes in the methodology, which were implemented through Procedure Change PC_2011_06[64] and contributed a reduction of 23% in the MRCP.

These methodology changes were compounded by a year-on-year reduction in the calculated Weighted Average Cost of Capital (WACC). This reduction was not the result of any methodological change, rather being driven by the higher demand for bonds, and falling bond yields, as a result of turbulence in global financial markets during 2011.

The majority of submissions on the 2014/15 MRCP have suggested that the WACC assumptions with regard to the capital structure of a generation business may not be appropriate for the current composition of the WEM. The IMO is committed to undertaking a review of these assumptions in 2012.

Stakeholders can find more information on the proceedings of the MRCPWG on the IMO's website[65].

7.9 Reserve Capacity Mechanism Review

The Reserve Capacity Mechanism Working Group (RCMWG) has been constituted by the MAC to consider, develop and assess changes to the Market Rules associated with various issues that have been identified in relation to the Reserve Capacity Mechanism.

The issues to be considered by the RCMWG are:

- The definition of capacity;
- Issues that impact surplus capacity, including the pricing of capacity in oversupply conditions;
- Harmonisation of supply-side and demand-side resources, including consideration of the fuel requirements for generation facilities and availability limits for DSM;
- The allocation of capacity costs to Market Customers;
- The impact of forecasting inaccuracy on the RCM;
- The alignment of the implementation of a dynamic Reserve Capacity refund regime and the potential changes to the RCM resulting from the deliberations of the RCMWG; and
- The timeline and scope of a periodic review of the RCM.

Work has commenced on the first three issues. The first RCMWG meeting took place in February 2012 and the group is required to provide its recommendations to the IMO Board by November 2012. Further information may be found at http://www.imowa.com.au/RCMWG.

[64] http://www.imowa.com.au/PC_2011_06
[65] http://www.imowa.com.au/MRCPWG

7.10 Review of the Planning Criterion and Demand Forecasting Process

The Market Rules require the IMO to undertake reviews at least once in every five years of the Planning Criterion and the process by which if forecasts SWIS peak demand.

The IMO has commenced these reviews, which are being undertaken in parallel. The IMO expects to publish draft reports by August 2012. This will be followed by a public consultation process, including stakeholder workshops.

Further information, including reports from the previous reviews conducted in 2007, may be found at http://www.imowa.com.au/rcreviews.

7.11 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 issues and identify solutions.

The RDIWG developed proposals for competitive Balancing and Load Following Ancillary Services (LFAS) markets and the Market Evolution Program (MEP) was established to introduce the ensuing changes.

The goal of the MEP has been to deliver a more efficient WEM for Western Australia. The MEP marks a significant evolutionary step for the WEM. Not only does it represent a significant volume of work undertaken by the industry and the IMO over a two year period, but it heralds the most significant evolutionary step in the WEM since Market start in 2006.

The IMO Board approved the Final Rule Change Report for RC_2011_10 in February 2012. The new Balancing and LFAS markets are scheduled to commence transitional operation on 1 July 2012, will full market implementation in December 2012.

The MEP delivers:

1. a new Balancing market that:
   - (i) ensures the most economically efficient options are used to provide Balancing services – whether it be IPP or Verve Energy generation; and
   - (ii) ensures that Verve Energy can be increasingly treated like other Market Participants over time even though it remains as the default balancer.
2. a new LFAS market that:
   - (i) ensures the most economically efficient options are used to provide LFAS – whether it be IPP 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 and resilient IT system with a longer life that:

(i) enables the MEP changes to be rolled out successfully; 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 implemented.

Further details can be found on the IMO's website[66].

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

Appendix 1 Abbreviations

ABS – Australian Bureau of Statistics

CCGT – Combined Cycle Gas Turbine

DBNGP – Dampier to Bunbury Natural Gas Pipeline

DSM – Demand Side Management

DSP – Demand Side Programme

EMC – Energy Market Commencement

ERA – Economic Regulation Authority

GBB – Gas Bulletin Board

GDP – Gross Domestic Product (for Australia)

GFC – Global Financial Crisis

GGP – Goldfields Gas Pipeline

GISP – Gas Information Services Project

GSEMC – Gas Supply & Emergency Management Committee

GSOO – Gas Statement of Opportunities

GSP – Gross State Product (for Western Australia)

GWh – Gigawatt-hour

IMO – Independent Market Operator

IPP – Independent Power Producer

KGP – Karratha Gas Plant

kV – Kilovolt

LEED – Low Emissions Energy Development (Fund)

LFAS – Load Following Ancillary Service

LGC – Large-scale Generation Certificate

LNG – Liquefied Natural Gas

LRET – Large-scale Renewable Energy Target

LT PASA – Long Term Projected Assessment of System Adequacy

MAC – Market Advisory Committee

MEP – Market Evolution Project

MRCP – Maximum Reserve Capacity Price

MRCPWG – Maximum Reserve Capacity Price Working Group

Mt – Megatonne

Mtpa – Million tonnes per annum

MW – Megawatt

MWEP – Mid West Energy Project

MWh – Megawatt-hour

NCMT – Network Connection Mapping Tool

NCS – Network Control Services

NEM – National Electricity Market

NIEIR – National Institute of Economic and Industry Research

NWSV – North West Shelf Venture

OCGT – Open Cycle Gas Turbine

PASA – Projected Assessment of Supply Adequacy

PJ – Petajoule

PoE – Probability of Exceedance

PV – Photovoltaic

RCM – Reserve Capacity Mechanism

RCMWG – Reserve Capacity Mechanism Working Group

RDIWG – Rules Development Implementation Working Group

REGWG – Renewable Energy Generation Working Group

RET – Renewable Energy Target

SEI – Strategic Energy Initiative

SOO – Statement of Opportunity Report

SRES – Small-scale Renewable Energy Scheme

STEM – Short Term Energy Market

SWIS – South West interconnected system

TJ – Terajoule

WACC – Weighted Average Cost of Capital

WEM – Wholesale Electricity Market

Appendix 2 Forecasts of Economic Growth

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

Year	Expected	High	Low
2007/08	3.8		
2008/09	1.4		
2009/10	2.3		
2010/11	2.0		
2011/12	2.7		
2012/13	3.0	3.6	2.5
2013/14	2.9	3.3	2.2
2014/15	2.3	3.4	1.4
2015/16	3.4	4.7	2.4
2016/17	4.1	5.5	2.9
2017/18	3.5	4.2	2.6
2018/19	2.7	2.8	2.2
2019/20	2.8	3.1	2.1
2020/21	2.7	3.1	1.7
2021/22	2.6	3.0	1.6
Average Growth %	**3.0**	**3.7**	**2.2**

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

Year	Expected	High	Low
2007/08	4.0		
2008/09	3.9		
2009/10	4.3		
2010/11	3.1		
2011/12	6.8		
2012/13	6.5	8.2	5.0
2013/14	4.8	7.2	3.2
2014/15	2.6	4.5	-0.3
2015/16	4.7	7.6	3.3
2016/17	7.9	9.3	5.6
2017/18	3.3	2.3	2.4
2018/19	0.3	1.2	-0.1
2019/20	2.2	3.4	0.8
2020/21	2.7	3.6	0.9
2021/22	2.9	2.8	-0.2
Average Growth %	**3.8**	**5.0**	**2.0**

Appendix 3 Forecasts of Summer Maximum Demand

Summer Maximum Demand Forecasts with Expected Economic Growth (MW)

Year	10% PoE	50% PoE	90% PoE
2007/08		3,392	
2008/09		3,515	
2009/10		3,766	
2010/11		3,831	
2011/12		3,854	
2012/13	4,460	4,164	3,946
2013/14	4,659	4,344	4,112
2014/15	4,804	4,474	4,231
2015/16	4,950	4,605	4,350
2016/17	5,135	4,772	4,505
2017/18	5,290	4,910	4,630
2018/19	5,419	5,023	4,730
2019/20	5,563	5,150	4,845
2020/21	5,711	5,281	4,965
2021/22	5,859	5,413	5,084
2022/23	5,990	5,528	5,187
Average Growth %	3.0	2.9	2.8

Summer Maximum Demand Forecasts with High Economic Growth (MW)

Year	10% PoE	50% PoE	90% PoE
2012/13	4,528	4,230	4,011
2013/14	4,743	4,425	4,191
2014/15	4,906	4,572	4,327
2015/16	5,095	4,747	4,490
2016/17	5,366	4,999	4,729
2017/18	5,694	5,310	5,027
2018/19	5,975	5,574	5,278
2019/20	6,151	5,733	5,425
2020/21	6,330	5,895	5,574
2021/22	6,502	6,050	5,717
2022/23	6,670	6,201	5,855
Average Growth %	3.9	3.9	3.9

Summer Maximum Demand Forecasts with Low Economic Growth (MW)

Year	10% PoE	50% PoE	90% PoE
2012/13	4,420	4,126	3,910
2013/14	4,587	4,275	4,046
2014/15	4,700	4,374	4,134
2015/16	4,820	4,480	4,229
2016/17	4,973	4,617	4,354
2017/18	5,108	4,735	4,461
2018/19	5,225	4,836	4,550
2019/20	5,345	4,941	4,644
2020/21	5,467	5,047	4,739
2021/22	5,581	5,146	4,826
2022/23	5,691	5,241	4,909
Average Growth %	2.6	2.4	2.3

Appendix 4 Forecasts of Winter Maximum Demand

Winter Maximum Demand Forecasts with Expected Economic Growth (MW)

Year	10% PoE	50% PoE	90% PoE
2007	2,705		
2008	2,774		
2009	2,944		
2010	3,029		
2011	3,008		
2012	3,186	3,108	3,055
2013	3,284	3,204	3,150
2014	3,351	3,269	3,213
2015	3,424	3,340	3,283
2016	3,542	3,455	3,396
2017	3,607	3,518	3,458
2018	3,637	3,547	3,486
2019	3,698	3,606	3,543
2020	3,767	3,673	3,609
2021	3,834	3,738	3,673
2022	3,872	3,774	3,708
Average Growth %	2.0	2.0	2.0

Appendix 5 Forecasts of Energy Sent Out

Forecasts of Energy Sent Out for the SWIS (GWh) – Capacity Year

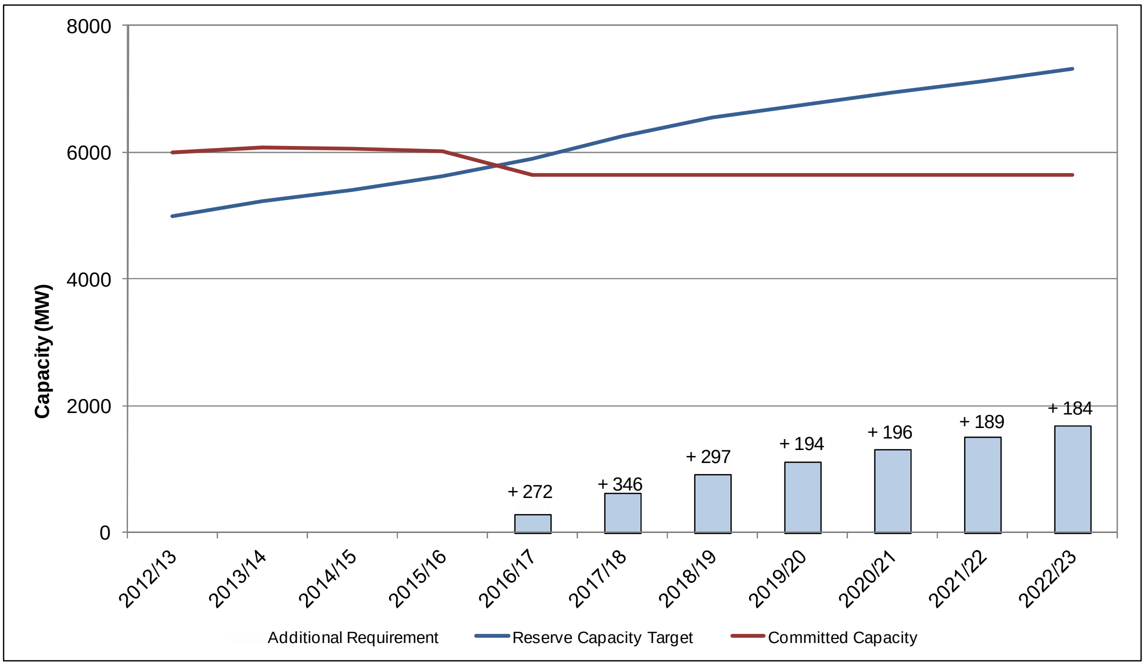
Year	Expected	High	Low
2007/08	16,519		
2008/09	16,690		
2009/10	17,500		
2010/11	17,857		
2011/12	17,611 (Projected)		
2012/13	17,563	17,938	16,961
2013/14	18,433	19,198	17,945
2014/15	18,711	19,647	17,889
2015/16	19,122	20,656	18,116
2016/17	19,814	22,095	18,521
2017/18	20,083	23,803	18,674
2018/19	20,141	25,191	18,685
2019/20	20,476	25,733	18,800
2020/21	20,827	26,397	18,920
2021/22	21,162	26,982	18,929
2022/23	21,277	27,525	18,906
Average Growth %	1.9	4.4	1.1

Forecasts of Energy Sent Out for the SWIS (GWh) – Financial Year

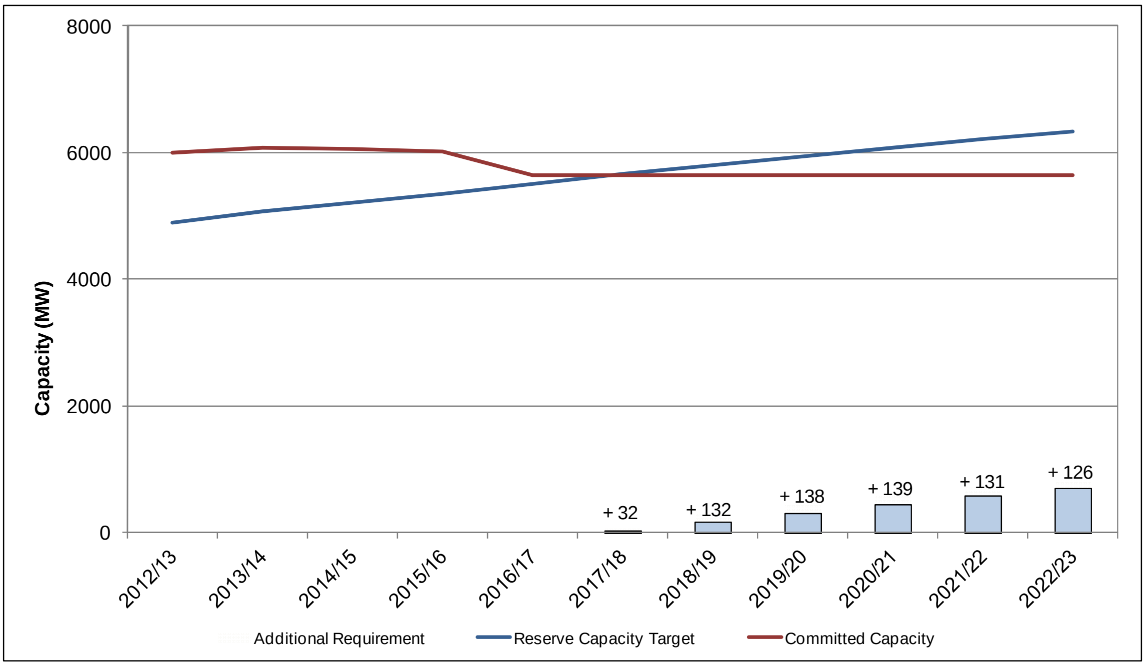
Year	Expected	High	Low
2007/08	16,387		
2008/09	16,628		
2009/10	17,342		
2010/11	17,925		
2011/12	17,673 (Projected)		
2012/13	17,585	17,884	17,099
2013/14	18,258	18,923	17,770
2014/15	18,619	19,498	17,865
2015/16	19,020	20,416	18,065
2016/17	19,651	21,742	18,429
2017/18	19,996	23,366	18,625
2018/19	20,112	24,808	18,673
2019/20	20,403	25,544	18,775
2020/21	20,741	26,223	18,891
2021/22	21,077	26,828	18,922
2022/23	21,237	27,383	18,909
Average Growth %	1.9	4.4	1.0

Appendix 6 Supply Demand Balance for High and Low Economic Forecasts

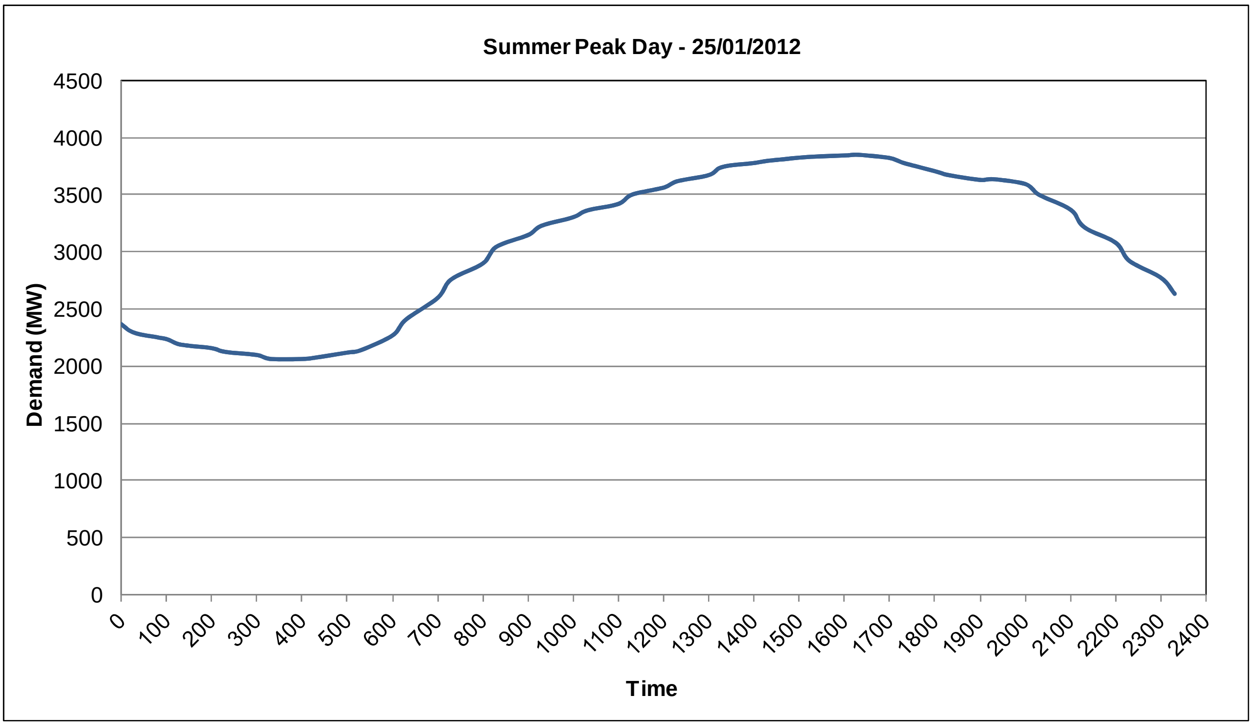
Required Generation and DSM Capacity in High Economic Growth Scenario

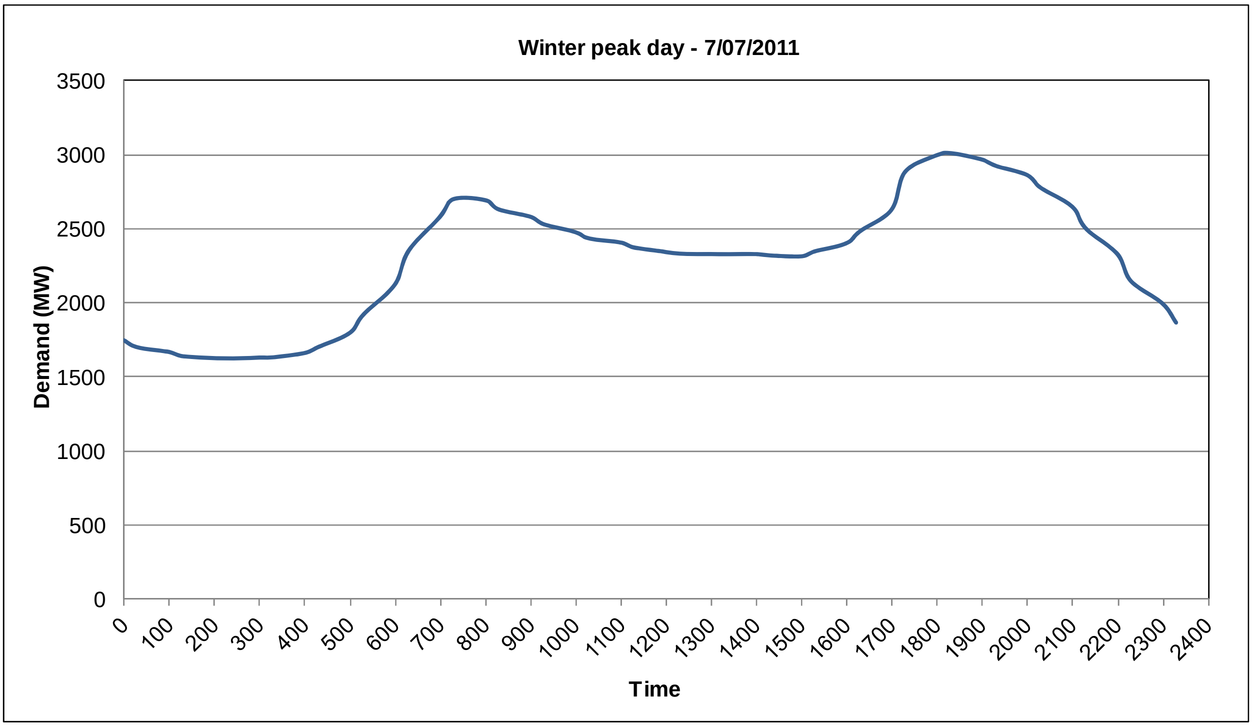


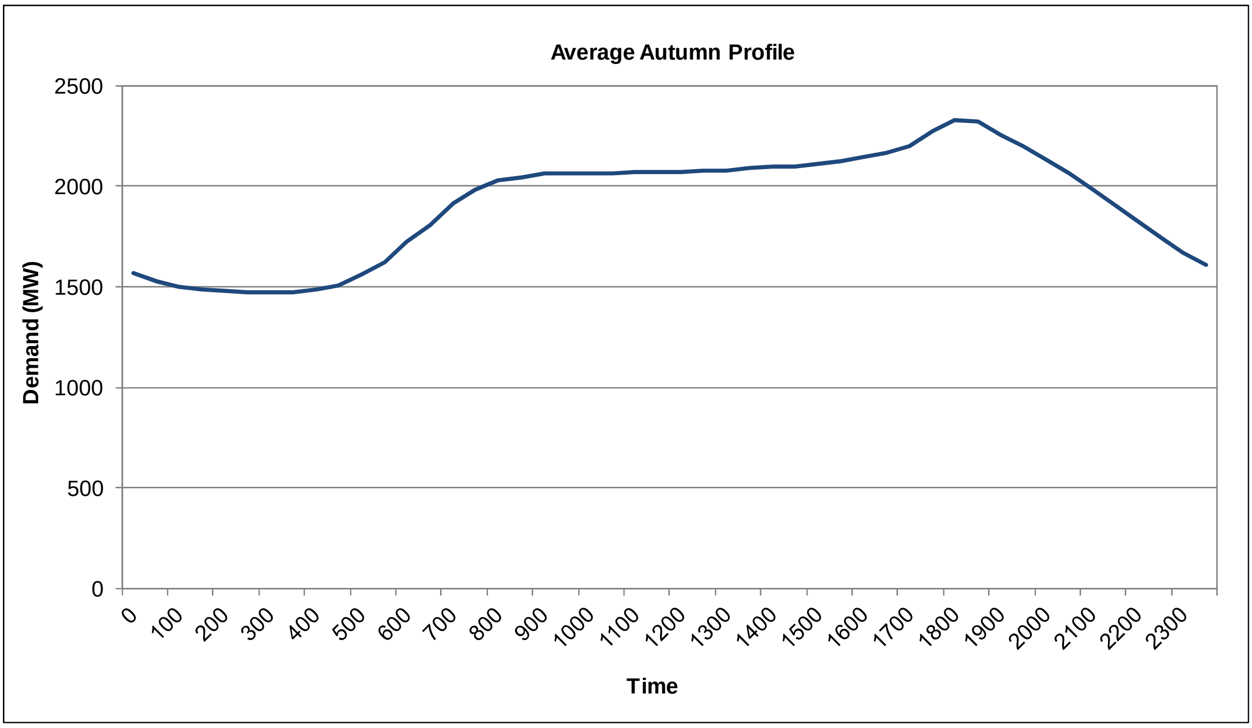
Required Generation and DSM Capacity in Low Economic Growth Scenario

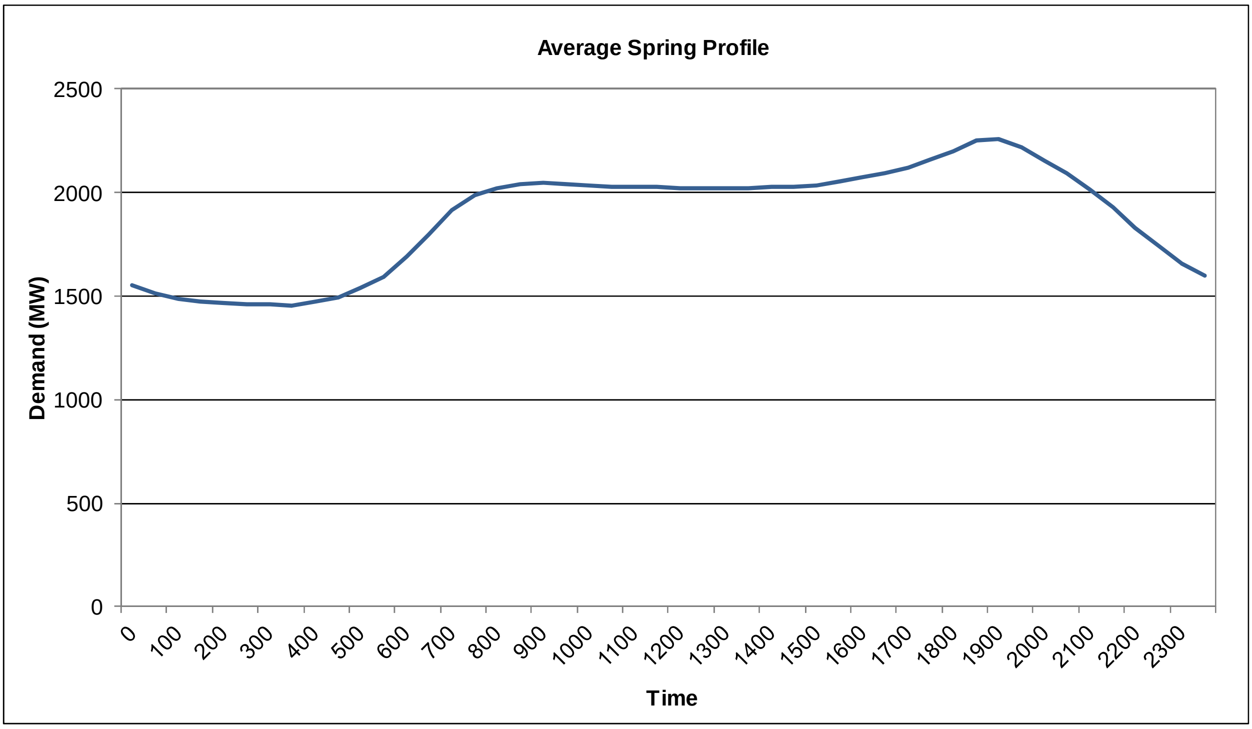


Appendix 7 Typical Daily Load Curves






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 from the average of the annual load curves from the last five years. The shape of this average load curve would be expected to approximate a 50% PoE demand profile, so it is then scaled up to match the 50% PoE peak demand and expected energy consumption forecasts for the relevant year.

   Experience from the most recent year with a 10% PoE peak demand event in the SWIS (2003/04) indicates that the 50% PoE load level was exceeded for less than 24 hours. Consequently, the Availability Curve outcome would be the same whether the 50% PoE peak demand forecast or 10% PoE peak demand forecast was used for the peak interval.

2. The reserve margin is added to the load curve (including the allowances for frequency keeping and Intermittent Loads) to form a “capacity requirement curve”. The capacity required for more than 24 hours per year, 48 hours per year and 72 hours per year is determined from this curve (clause 4.5.12(a)).

3. 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 plant outages and for variation in the output of Intermittent Generators. For existing facilities, future outage plans (based on information provided by Market Participants under clause 4.5.4) are included in this consideration.

4. 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 be 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 515 MW[67], thus breaching the criteria for evaluating Outage Plans.

The Availability Curve (the capacity associated with each Availability Class in Table 5) is then calculated from the capacity requirement curve and the Minimum Generation according to the method outlined in clause 4.5.12(c) of the Market Rules.

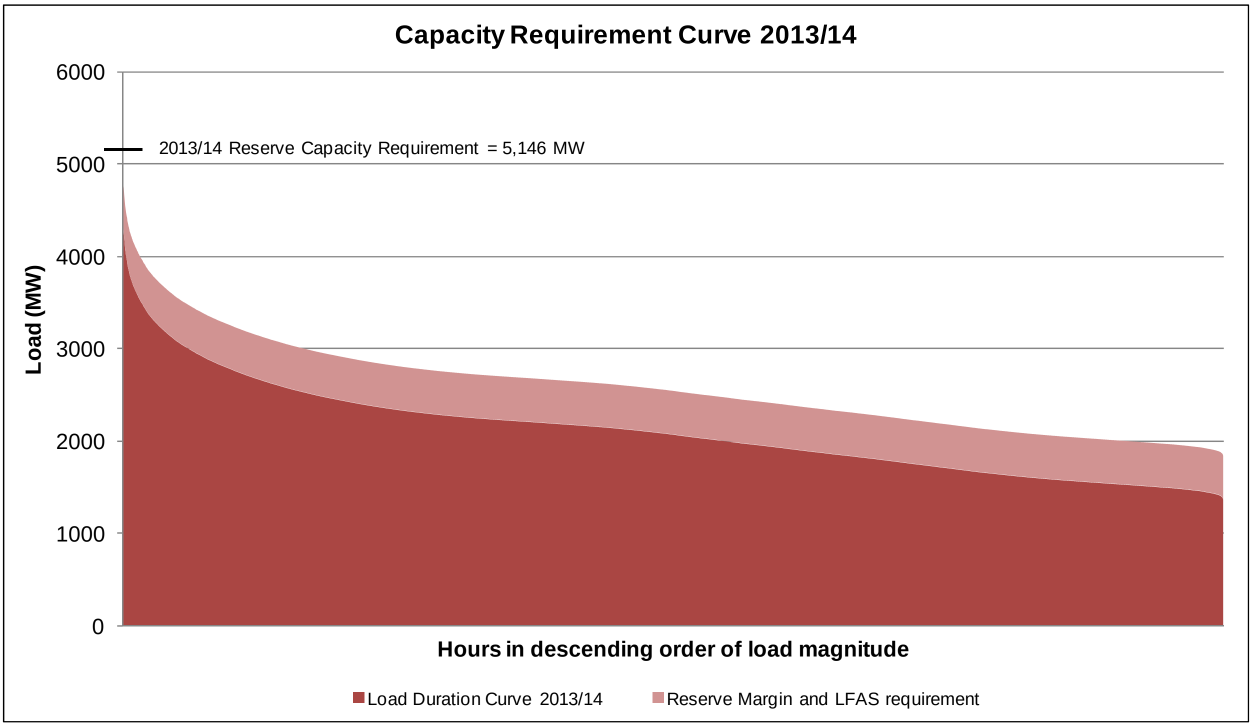
- Availability Class 4 is defined as the Reserve Capacity Requirement less the greater of the capacity required for more than 24 hours and the Minimum Generation;
- Availability Class 3 is defined as the Reserve Capacity Requirement less the greater of the capacity required for more than 48 hours and 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 more than 72 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.

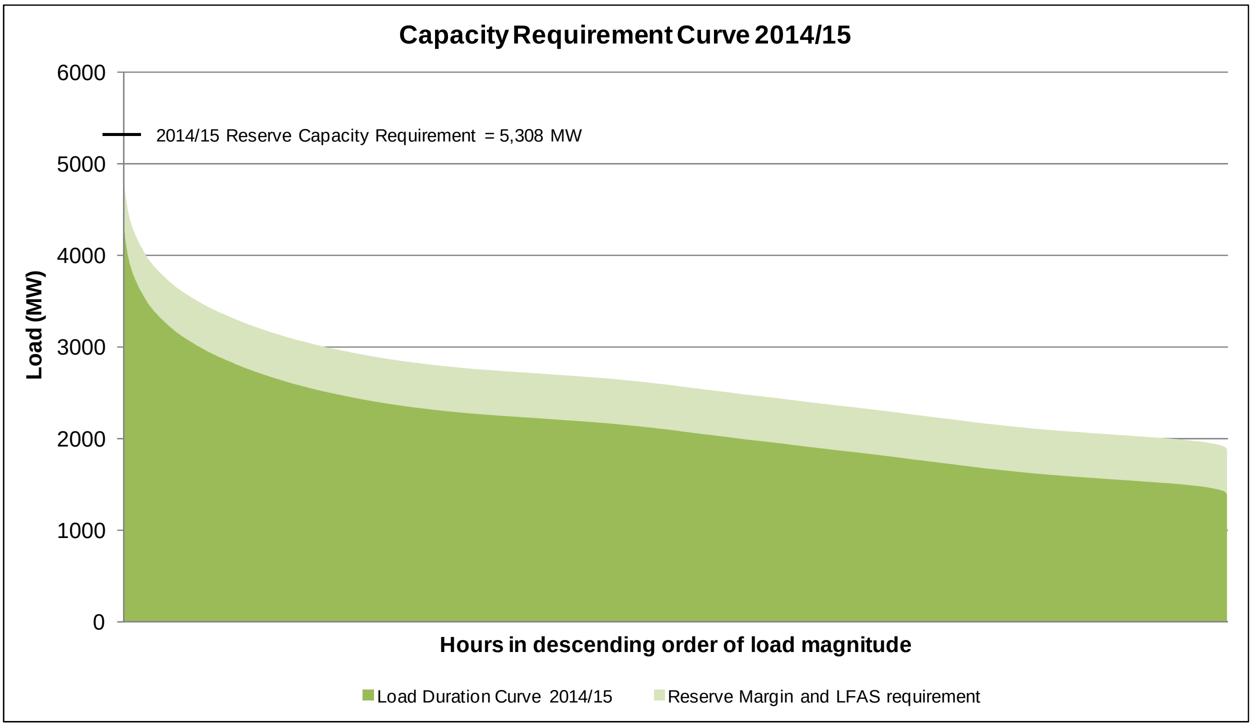
The IMO notes that the methodology for determination of the Availability Curve has evolved in recent years. A number of refinements have been introduced since last year.

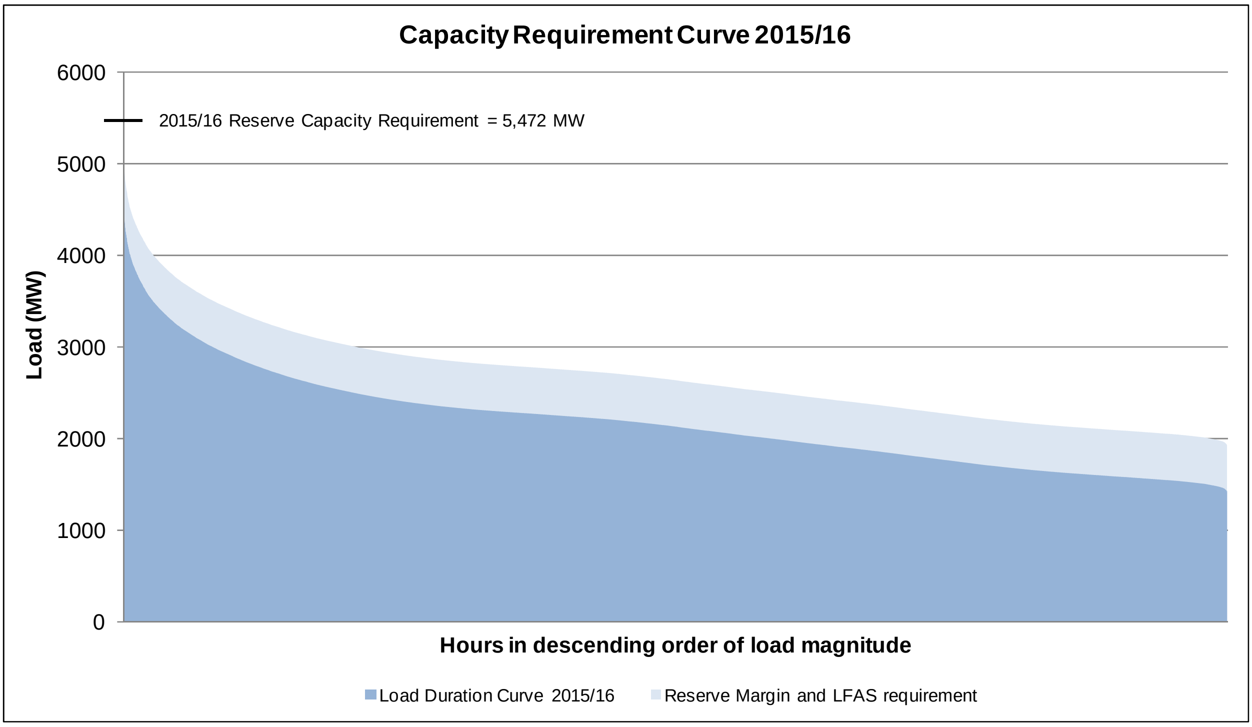
- Previous determinations accounted for the annual limitation on the availability of DSP's, but did not consider the other limitations such as the maximum number of hours of curtailment per day that is specified by providers of DSM capacity, or the potential unavailability of DSM on the third consecutive day as allowed under clause 4.12.8 of the Market Rules. PA Consulting has modelled these restrictions this year.
- The IMO previously determined the capacity required for 24 hours per year, 48 hours per year and 72 hours per year based on the forecast load duration curve. However, this implied that the full reserve margin was only required for less than 24 hours. As noted in point 2 above, the reserve margin has been included in the capacity requirement curve this year. This approach is consistent with both the current Market Rules, and with Pre-Rule Change Proposal PRC_2012_09 that was presented by System Management at the MAC meeting on 13 June 2012[68].
- Rule Change RC_2011_14[69] commenced on 6 June 2012 and has amended the calculation of the Availability Requirements in clause 4.5.12(c) of the Market Rules. The earlier methodology implicitly assumed that the capacity in each Availability Class would be available for the maximum number of hours applicable to that class. The amended Market Rules assume that the capacity is available for minimum number of hours applicable to the Availability Class, which is consistent with observed behaviour in the market.

The capacity requirement curves for the 2013/14, 2014/15 and 2015/16 Capacity Years are shown below.

[67] The quantity required to provide Ancillary Services and satisfy the Ready Reserve Standard, consistent with the information published in the Medium Term Projected Assessment of Supply Adequacy (PASA) at http://www.imowa.com.au/mtpasa.html.
[68] Available at http://www.imowa.com.au/MAC_50
[69] Available at http://www.imowa.com.au/rc_2011_14


Capacity Requirement Curve 2013/14
6000
5000
4000
3000
2000
1000
0
Load (MW)
2013/14 Reserve Capacity Requirement = 5,146 MW
Hours in descending order of load magnitude
Load Duration Curve 2013/14
Reserve Margin and LFAS requirement


Capacity Requirement Curve 2014/15
6000
5000
4000
3000
2000
1000
0
Load (MW)
2014/15 Reserve Capacity Requirement = 5,308 MW
Hours in descending order of load magnitude
Load Duration Curve 2014/15
Reserve Margin and LFAS requirement


Capacity Requirement Curve 2015/16
6000
5000
4000
3000
2000
1000
0
2015/16 Reserve Capacity Requirement = 5,472 MW
Load (MW)
Hours in descending order of load magnitude
Load Duration Curve 2015/16
Reserve Margin and LFAS requirement

Appendix 9 Facility Capacities

Registered Generation Facilities - Existing and Committed

Participant Name	Facility Name	Capacity Credits (2013/14)
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	179.063
Alinta Sales	ALINTA_WGP_U2	179.063
Alinta Sales	ALINTA_WWF	39.059
Blair Fox	BLAIRFOX_KARAKIN_WF1	1.008
Collgar Wind Farm	INVESTEC_COLLGAR_WF1	90
EDWF Manager	EDWFMAN_WF1	28.639
Goldfields Power	PRK_AG	61.4
Griffin Power	BW1_BLUEWATERS_G2	215.9
Griffin Power 2	BW2_BLUEWATERS_G1	215.9
Landfill Gas & Power	CANNING_MELVILLE	0.789
Landfill Gas & Power	KALAMUNDA_SG	1.3
Landfill Gas & Power	RED_HILL	3.04
Landfill Gas & Power	TAMALA_PARK	3.814
Mt.Barker Power Company	SKYFRM_MTBARKER_WF1	0.935
Mumbida Wind Farm	MWF_MUMBIDA_WF1	14.75
Namarkkon	NAMKKN_MERR_SG1	82
NewGen Power Kwinana	NEWGEN_KWINANA_CCG1	320
NewGen Neerabup Partnership	NEWGEN_NEERABUP_GT1	330.6
Perth Energy	ATLAS	0.834
Perth Energy	GOSNELLS	0.486
Perth Energy	ROCKINGHAM	1.711
Perth Energy	SOUTH_CARDUP	2.688
Skyfarming	DCWL_DENMARK_WF1	0.61
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
Tiwest	TIWEST_COG1	36
Verve Energy	ALBANY_WF1	6.573
Verve Energy	BREMER_BAY_WF1	0.098
Verve Energy	COCKBURN_CCG1	231.8

Participant Name	Facility Name	Capacity Credits (2013/14)
Verve Energy	COLLIE_G1	316
Verve Energy	GERALDTON_GT1	15.8
Verve Energy	GRASMERE_WF1	4.482
Verve Energy	GREENOUGH_RIVER_PV1	2.733
Verve Energy	KALBARRI_WF1	0.538
Verve Energy	KEMERTON_GT11	145.5
Verve Energy	KEMERTON_GT12	145.5
Verve Energy	KWINANA_G5	177.5
Verve Energy	KWINANA_G6	184
Verve Energy	KWINANA_GT1	15.1
Verve Energy	KWINANA_GT2	92.156
Verve Energy	KWINANA_GT3	92.156
Verve Energy	MUJA_G5	195
Verve Energy	MUJA_G6	186.5
Verve Energy	MUJA_G7	211
Verve Energy	MUJA_G8	211
Verve Energy	MUNGARRA_GT1	33
Verve Energy	MUNGARRA_GT2	32.25
Verve Energy	MUNGARRA_GT3	32
Verve Energy	PINJAR_GT1	32.15
Verve Energy	PINJAR_GT10	109
Verve Energy	PINJAR_GT11	118
Verve Energy	PINJAR_GT2	31.45
Verve Energy	PINJAR_GT3	37
Verve Energy	PINJAR_GT4	37
Verve Energy	PINJAR_GT5	37
Verve Energy	PINJAR_GT7	37
Verve Energy	PINJAR_GT9	109
Verve Energy	PPP_KCP_EG1	80.4
Verve Energy	SWCJV_WORSLEY_COGEN_COG1	107
Verve Energy	WEST_KALGOORLIE_GT2	34.25
Verve Energy	WEST_KALGOORLIE_GT3	18.4
Vinalco Energy	MUJA_G1	55
Vinalco Energy	MUJA_G2	55
Vinalco Energy	MUJA_G3	55
Vinalco Energy	MUJA_G4	55
Western Energy	PERTHENERGY_KWINANA_GT1	108

Participant Name	Facility Name	Capacity Credits (2013/14)
Waste Gas Resources	HENDERSON_RENEWABLE_IG1	2.34

Registered DSM Facilities - Existing and Committed

Participant Name	Facility Name	Capacity Credits (2013/14)	Availability (hr / year)
Alinta Sales	ALINTA_DSP_01	3	24
Alinta Sales	ALINTA_DSP_02	8.2	24
Alinta Sales	ALINTA_DSP_03	3.6	24
Alinta Sales	ALINTA_DSP_04	1	24
Alinta Sales	ALINTA_DSP_05	0.5	24
Amanda Australia	AMAUST_DSP_01	9.9	24
Barrick (Kanowna)	KANOWNA_DSP_01	11	24
EnerNOC Australia	ENERNOC_DSP_01	90	24
EnerNOC Australia	ENERNOC_DSP_02	100.086	24
EnerNOC Australia	ENERNOC_DSP_03	50	24
EnerNOC Australia	ENERNOC_DSP_04	36	24
Griffin Power	GRIFFIN_DSP_01	20	48
Premier Power Sales	PREMPWR_DSP_01	10	24
Premier Power Sales	PREMPWR_DSP_03	23	48
Premier Power Sales	PREMPWR_DSP_04	6	24
Premier Power Sales	PREMPWR_DSP_05	3	24
Premier Power Sales	PREMPWR_DSP_06	2	24
Premier Power Sales	PREMPWR_DSP_07	2	24
Synergy	SYNERGY_DSP_01	10	32
Synergy	SYNERGY_DSP_02	5	32
Synergy	SYNERGY_DSP_03	5	32
Synergy	SYNERGY_DSP_04	40	48
Water Corporation	WATERCORP_DSP_01	20.5	24
Water Corporation	WATERCORP_DSP_02	18	24
Water Corporation	WATERCORP_DSP_03	22	24