Implications of extreme weather for the Australian National Electricity Market: historical analysis and 2019 extreme heatwave scenario

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About Sapere Research Group Limited

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Glossary

AEMO  Australian Energy Market Operator – it encompasses both system operations (scheduling) and market (dispatch and price setting) functions.

AMD  Annual maximum demand

BoM  Bureau of Meteorology

EHF  Excess heat factor, a measure of the combined effect of excess heat and heat stress used to define heatwave severity thresholds.

EHFx  Excess heat factor expressed as a multiple of the local severe heatwave threshold (LSHT)

EWE  Extreme weather event

Firm capacity  The minimum available generation capacity at the time of expected maximum demand for both winter and summer. For thermal generation, this relates to capacity at a given ambient temperature. For variable generation, such as wind, this is expressed as a percentage of total capacity.

LOR (1,2,3)  Lack of Reserve, when, for the nominated period, the AEMO declares there are insufficient short-term capacity reserves available. There are three levels of LOR up to customer load being interrupted automatically or manually in order to maintain or restore the security of the power system (see UFLS)

LSHT  Local severe heatwave threshold, the threshold value of EHF to identify a heatwave as severe relative to the specific climatology of each location

MPC  Market price cap, the maximum price at which electricity can be bid, offered, or scheduled in the market

MTPASA  Medium Term Projected Assessment of System Adequacy, AEMO’s forecast of supply and demand

Nameplate capacity  Nominal or rated capacity of a generator, transformer or other. Capacity may be contingent on ambient temperature.

Native demand  A broader measure of demand compared with operational demand, as it includes Small scale non-scheduled generation (SNSG), which reduces demand and may increase supply

NEM  National Electricity Market

NESA  National Energy Security Assessment

Operational demand  It is the measure of demand used for NEM dispatch and market pricing purposes

PV  Photo-voltaic panels that convert solar energy to electricity
RERT  Reliability and Emergency Reserve Trader – a security service contracted by the AEMO to maintain reserves while the demand-supply balance is restored

ROI  Reviewable Operating Incident, an unusual power system event meeting guidelines established by the Reliability Panel requiring investigation by the system operator

SNSG  Small scale non-scheduled generation (typically less than 30MW). Treatment of SNSG is a key difference between operational and native demand

UFLS  Under frequency load shedding – maintains system stability by shedding demand

USE  Unserved Energy (at bulk supply points)

VCR  Value of Customer Reliability – a measure of the economic cost of an electricity supply outage.

Comments on subsequent developments as at January 2015

Inputs for the scenario modelling in this report were finalised in the early part of July 2014. Developments between early July and January 2015 include:

•  Publication of the AEMO’s 2014 Statement of Opportunities (ESOO). The scenario modelling relied on updates from the 2013 ESOO.
•  Repeal of the carbon price in mid-July 2015 (effective from 1 July). This may increase demand and hence make the low demand alternatives in the stress scenario analysis less likely.
•  Reviews of the future profile of the Renewable Energy Target. The stress scenario analysis assumed no additional renewable capacity beyond that already committed at the time of the 2013 ESOO.
•  The announcement of the full closure of a peaking gas power station in South Australia (Pelican Point), in 2015. The stress scenario analysis assumed half of its summer rated capacity would be available.
•  An ongoing process to reduce transmission congestion in Regional Victoria (Regional Victorian Thermal Capacity Upgrade). The outcome of this process could reduce transmission congestion between South Australia and Victoria, compared to that assumed in the scenario analysis.
•  Finalisation of a network pricing rule change by the AEMC in November 2014. Along with a broader suite of demand side focused measures, this reform could place downward pressure on coincident peak demand across the NEM relative to the assumptions in the stress scenario analysis.

There is of course a high level of uncertainty over future demand and supply conditions during the stress scenario in February 2019. Some of these developments increase energy security, while others reduce it. The key conclusions in this report are not materially affected by these developments: while there are risks to energy security in early 2019, especially for South Australia and Victoria, these risks appear to be no greater than they were in January 2014.
Executive summary

Sapere has been retained by the Australian Department of Industry (the Department) to prepare a report on the impact of extreme weather events on the National Electricity Market (NEM), to inform the Department’s preparation of a third National Energy Security Assessment (NESA). Part one of the report consists of an analysis of data and reports on extreme weather events. Part two develops a “stressor” scenario to assess the resilience of the NEM's physical and market operations during prolonged, extreme heatwaves over the short- to medium-term (up to five years).

The central question to be addressed is:

*Will the security of the NEM physical and market operations be affected by the increased severity, frequency and duration of heat-wave events in the short to medium term?*

Key findings are:

- The outlook for the future security and reliability of the NEM in the summer of 2019 appears to be better than it was in January 2014 when areas of Southern Australia experienced an extreme heatwave. This finding is after taking into account both changes in the future generation mix and the increasing future probability and severity of extreme heatwaves.

- The costs attributable to extreme heatwaves could represent well in excess of a third of typical electricity retail household bills. These costs contributed to a 70 per cent real increase in retail electricity prices over the last 5 years.

- Both the frequency and severity of extreme heatwaves have measurably increased over the study period (January 1999-April 2004).

- Available power system data appear to indicate a higher number of extreme weather events affecting the NEM after 2007, relative to the period 1998-2007. This may reflect better data availability and reporting post 2007 and not represent a real trend.

- Over the last three or four years, heatwaves and bushfire events have had little significant impact on power system security. This suggests that the direct impact of heatwaves on NEM markets may be decreasing, even while their frequency and severity increases.

- The likely recent improvement in reliability is mainly attributable to forecast demand moderation, especially in the NEM regions (Victoria and South Australia) most at risk during extreme heatwaves. This moderation is in large part due to energy efficiency measures and the impact of rooftop solar Photo-Voltaic (PV) generation.

Context

For the purposes of this report, energy security is defined as the reliable, sustainable, and competitive availability of energy to support Australia’s economic, social and natural environments.

*A reliable energy system provides energy with minimal disruptions; supply is adequate to support economic and social activities; systems, operations and processes are*
dependable; governance and regulation measures are trustworthy; market conditions are stable and consistent.

A sustainable energy system is forward-looking and innovates to address changing circumstances; it plans for unexpected events and mitigates internal and external pressures; it supports social and environmental aspirations; vulnerabilities are identified and managed.

A competitive energy system provides energy at an affordable price that does not adversely affect the competitiveness of the economy, and supports continued investment in the energy sector.

The NEM consists of five major wholesale pricing and bulk supply planning regions: Queensland, NSW, South Australia, Victoria and Tasmania. Transmission “interconnectors” enable the export and import of electricity and reserve capacity between these regions. These are highlighted in orange in Figure 1 below.

The NEM transmission network is the largest continuous electricity grid in the world, by extent. It encompasses a number of climate zones from a tropical environment in Far North Queensland, warm and mild temperate climates in southern continental States, to a cool temperate climate in Tasmania and mainland alpine regions.

No historical Extreme Weather Event (EWE) has simultaneously affected all regions of the NEM. This substantially improves the systemic resilience of the grid because transmission interconnectors between regions enable the transfer of reserve capacity (security) and energy to regions that are under stress.

On the other hand, the long and often remote nature of transmission and interconnectors exposes bulk supply to environmental risks. In addition, outages in one region can sometimes cause shortfalls or outages in other regions.

The current NEM reliability standard set by the NEM Reliability Panel is measured in terms of maximum expected unserved energy (USE). Since the NEM was formed in 1998, the reliability standard means that out of 100,000MWh of demand, no more than 2MWh of outage should be allowed.

The NEM reliability standard relates to bulk supply. Although severe weather disruption of the grid at the distribution level can be significant, affecting wide areas for reasonable periods of time, this impact is local. Generally, large numbers of consumers are only affected by localized extreme weather in high density urban areas. The focus of this report is on security of bulk supply relative to demand.
Expert analysis of global and Australian historical climate data indicates that the incidence and severity of extreme weather events has already increased in recent decades.1 These extreme weather events include extreme heat wave events, extreme precipitation events and extreme cyclone (wind events). In Australian conditions, there is a higher frequency and severity of conditions conducive to bushfires.

The analysis of climate data undertaken for this report also indicates that over the period since 1998, the number of extreme heatwaves has steadily increased. There were 1.2 extreme heatwave events per annum in the first five year period, 2.4 in the second and 3.0 in the third. In addition, the number of extreme heatwave days increased from 15 for 1999-2003 to 26 for 2009-2013.

Expert climate analysis suggests that further global warming implies the future rate of increase in both the frequency and severity of extreme weather events, including heatwaves, will substantially exceed the historical rate of increase in frequency and severity. This reflects a structural change in the risk profile for these events.

**Part One - Historical analysis**

Heatwaves, especially extreme heatwaves, are the most important environmental threat both to the security of the NEM's physical power system and to the market. Extreme heatwaves are strongly associated with super peaks in demand.

There have been 54 EWE’s between January 1999 and May 2014, as defined in this report. Figure 6 illustrates the type and occurrence of these EWEs.2

**Figure 2 Timeline of extreme weather events**

Available power system data appear to indicate a higher number of system events after 2007, relative to the period 1998-2007. This may reflect better data availability and reporting post 2007 and not represent a real trend.

Over the last three or four years, heatwaves and bushfire events have had little significant impact on power system security. This suggests that the direct impact of heatwaves on NEM markets may be decreasing, even while their frequency and severity increases.

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2 Cold and wet extreme weather events are depicted below the line to highlight their frequency relative to heat related extreme weather. Cold/wet events do not represent negative events. Appendix 1 provides further information for each of these events.
Lower than expected demand growth, and falling demand in recent years, are contributing to the reduced impact of extreme heatwaves. For example, there is now significant excess generation capacity in most parts of the NEM.

The reduced impact may also be attributable in part to improvements in the NEM’s operational resilience. These include improvements in system management and security related investments.

Cold and wet extreme weather has less NEM impact. This type of EWE is generally not associated with high demand. These types of EWE are generally local or at most, regional, in extent. They are damaging to distribution and occasionally to transmission assets, but not to an extent that the power system cannot be reconfigured to maintain bulk supply. Typically, in cold/wet EWE, bulk supply (transmission) is re-established before load (distribution).

Genuine shocks to the system come through unpredictable events. Although not weather related, the Latrobe Valley earthquake of 19 June 2012 is included as a power system event with a very significant impact.

The threats EWEs pose to NEM security take various forms: key physical impacts include low reserves and unserved energy. Other impacts can include damage and loss to electricity infrastructure, higher insurance premiums and reinsurance costs, and other operating and maintenance costs.

Although power system incidents caused by environmental conditions are a minority of all power system incidents identified as having “significant” physical impact on the NEM, heatwaves and bushfires are associated with three quarters of these. This includes three events where unserved energy (USE) exceeded 1000MWh.

These USE events or supply outages result in business losses and disruption to communities and families. If the cost to a typical consumer for a supply outage is $20,000/MWh, then a 30 minute 1000MW outage implies a cost of $10m. On this basis the cost of the three greatest USE events are as follows:

- $46m for the 2009 South East Australia extreme heatwave;
- $34.7m for the 2007 Great Dividing Complex fires and severe heatwave; and
- $30m for the 2001 bushfire triggered islanding event.

Even if the assumed cost of USE were doubled, the economic cost of USE is modest relative to electricity supply costs. In particular, the cost is modest relative to the cost of maintaining supply during maximum demand.

Ensuring the power system can maintain reliable supply during extreme heatwave events affects affordability/competitiveness, substantially increasing network and wholesale market costs, and therefore consumer bills. The Productivity Commission has concluded that peak demand (shown in this report to coincide with extreme heatwaves) adds $350 per year to typical power bills.

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3 The majority of power system incidents have primary causes identified as customer, transmission or generator equipment failures, protection and control issues, operating errors or inadequate processes.
This $350 per annum value is equivalent to between 22.2 per cent and 36.7 per cent of annual wholesale and network supply costs for a typical customer in the NEM. The variability reflects differences in typical annual consumption, network and wholesale costs.

The Productivity Commission’s estimate only covers infrastructure costs – network and generation capacity. If generator fuel costs and USE associated with peak demand are included, the cost would exceed $350 per year. This suggests that costs attributable to extreme heatwaves could represent well in excess of a third of typical electricity retail supply costs and household bills.

The historical analysis also found that:

- Unlike other extreme weather events, heatwaves can be widespread and able to affect up to five of the six NEM regions simultaneously.
- Heatwaves and high demand are linked, increasingly driven by the widespread penetration of air-conditioning, and in all states (except Tasmania) are associated with annual maximum demand.
- Heatwaves are strongly associated with bushfires and lightning strikes, which pose the most significant environmental threat to the power system at a bulk supply level.
- Heatwaves are associated with a reduction in transmission and generation capacity because equipment operates close to technical limits.
- High demand during extreme heatwaves results in congestion on key interconnectors – this reduces the extent surplus reserve capacity and energy in one region can be shared with another.
- Heatwaves and/or bushfires are already adversely affecting the security of the power system in terms of lost generation and load, and USE.

**Part Two - 2019 scenario**

The outlook for the future security and reliability of the NEM in the summer of 2019 appears to be better than it was in January 2014. This finding is after taking into account both changes in the future generation mix and the increasing future probability and severity of extreme heatwaves.

A number of variables and stressors are tested in the extreme heatwave scenario. This is set in February 2019 to test the impact on the NEM of a more severe repetition of the 2014 heatwave experienced in Southern Australia in January 2014.

The high demand scenario from the AEMO’s 2014 National Energy Forecast Report (NEFR) is tested as it assumes a substantially higher maximum demand compared with the other two scenarios. All three AEMO demand scenarios already seek to take into account the increasing frequency and severity of extreme heatwaves.

The scenario assumes the extreme heatwave results in maximum demand exceeding a one in 50 year event threshold in Victoria, Tasmania and NSW/ACT. A lower one in 10 year threshold is applied for South Australia. This reflects the fact that the maximum demand peak in South Australia is likely to occur more than 2 hours later than in Victoria. This difference is partly a result of the impact of rooftop PV generation, especially in South Australia, which has deferred the time of day when maximum demand occurs.
Under assumed record heatwave conditions, there is a high likelihood that critical interconnectors would be impaired, due to technical operating limits. Accordingly, it is assumed interconnector capacity is impaired in some cases, and lost altogether in others. This is especially relevant given the high probability of bushfires occurring under the stress scenario.

Low reserves could be experienced in Victoria. This reflects the impact of an assumed constraint on the Basslink interconnector alongside the more limited impact for Victoria of returning currently offline generation to service.

The modelling shows that, in some circumstances, there is a high likelihood of significant and costly outages in South Australia and Victoria. In other cases, however, there are low reserves, but possibly no outages.

It is assumed there is no new thermal generation capacity installed in Victoria or South Australia, the two jurisdictions with the tightest supply-demand balance during extreme heatwaves. The AEMO’s conservative forecasts of firm wind (8.9 per cent of installed capacity in South Australia during summer) are applied. It is also assumed there is no additional wind capacity beyond the existing and committed capacity at the time of the 2013 AEMO Electricity Statement of Opportunities.4

Under the AEMO’s high demand scenario, it seems likely that some or all of the 2,298MW of offline generation could be returned to service. While this would increase total NEM reserves, it would have relatively little impact on Victoria, where there is only 95MW of offline generation.5 The modelling highlights that, if demand tracks closer to the AEMO’s low scenario prediction, or wind output is higher, it is likely that supply is sufficient to meet maximum demand.

In addition to modelling, the scenario analysis took into account a range of other relevant considerations. These include: the evolving generation mix; regional islanding and frequency control; native and operational demand; existing generator financing risks; peaking gas generation risks; drought; risks around the return of offline generation; Reliability and Emergency Reserve Trader (RERT); and demand side participation.

### Energy security under future extreme heatwaves

#### Reliability

Based on modelling of an extreme heatwave scenario, it appears future changes in the generation mix are unlikely to reduce the security of future NEM physical and market operations. Despite the increasing frequency and severity of extreme heatwaves, the outlook for the future security of the NEM in the summer of 2019 appears to be no worse than it was in January 2014.

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4 The AEMO published its 2014 ESO after the completion of the scenario analysis. The key developments in the 2014 ESO relevant to the analysis have been taken into account, by reference to regular AEMO updates on generator withdrawals.

5 For modelling purposes, Anglesea Power station has been included in the scenario, on the assumption it continues to trade following the closure of the Port Henry Smelter.
South Australia and Victoria have the greatest risk of bulk supply losses. Taken as a whole, the modelling indicates that any outages would be within mandated reliability of supply parameters. In other words, the expected cost of outages (USE) is substantially exceeded by the cost of additional power system investment to increase security.

The likely recent improvement in reliability is attributable to forecast demand moderation, especially in the NEM regions (Victoria and South Australia) most at risk during extreme heatwaves. This moderation is partly due to energy efficiency measures and the impact of rooftop solar PV. (Solar PV output and energy efficiency is treated as negative demand for forecasting purposes.)

Another benefit of rooftop solar PV is that it defers the time of day when maximum demand would be experienced in Adelaide. This reduces the risk that maximum demand for both Adelaide and Melbourne would occur at exactly the same time during a large scale (multi-State) extreme heatwave event.

Moderating demand is partly being offset by generation capacity being withdrawn from service. Nearly 4000MW of capacity has been withdrawn since mid-2012. Any further generation withdrawals in Victoria and South Australia could pose risks to physical system security.

**Sustainability**

Existing market and planning mechanisms appear sufficient – with reservations identified below – to anticipate and respond to changing circumstances and emerging vulnerabilities. Technical changes relating to frequency control are currently in development to manage system stability under conditions where wind represents a larger share of the future generation mix.

A possible area of concern relates to the future availability of gas fired peaking generation. This reflects the falling value of this capacity, due to the flat and possibly declining outlook for maximum peak demand. This is likely to be placing downward pressure on expected revenues. At the same time, gas supply costs appear to be increasing in anticipation of Queensland liquefaction facilities coming online.

If actual demand tracked the AEMO’s high growth scenario, it could reasonably be expected that most currently offline generation could be brought back into service. This would improve the supply/demand balance but would not remove the risks of short duration outages under a stressor (1 in 50 year event) extreme heatwave, alongside generation and transmission outages.

The Reliability and Emergency Reserve Trader (RERT) provides up to a 90 minute reserve buffer to enable demand and supply to be balanced. The closure of the Port Henry aluminium smelter in Victoria implies changes to the procurement of the RERT will be required. It seems likely that alternative demand side options could be procured to supply a similar service. For example, it is possible that desalination plants or other large energy users could supply RERT services.

A number of proposals are under consideration to improve demand side participation. This includes pricing reform and other incentives to temper demand during high price periods. If these proposals were implemented and effective by the time of any 2019 extreme heatwave,
they could moderate demand, thereby increasing security reserves and reducing the risk of supply shortfalls.

For small customers, electricity prices in the NEM are averaged over time and therefore over different types of customers. This means demand side response during extreme heatwaves is limited to larger electricity consumers, rather than to all consumers.

As highlighted in the Productivity Commission’s 2012 report, retail pricing in the NEM during extreme heatwaves do not reflect the very high cost of maintaining electricity supplies during these events. This is likely to be undermining the sustainability aspect of energy security. This is because retail electricity pricing structures are likely to lead to excess use of and investment in NEM physical capacity to meet demand during extreme heatwaves. This is likely to be driven by demand from consumers who are able to ‘free ride’ during super peak price periods. At the same time, inefficient pricing suppresses demand at other (non-super peak price) times and by other users. This may be contributing to flat or falling NEM wide demand.

**Competitiveness and affordability**

Competitiveness and affordability has substantially declined in recent years due to a 70 per cent increase, in real terms, in typical retail electricity prices for small consumers between June 2007 and December 2012. While price increases for large industrial and commercial consumers is likely to be less than 70 per cent, they are nevertheless substantial.

The cost of meeting demand during extreme heatwaves is likely to exceed one third of the cost of supplying typical electricity consumers in the NEM. Extreme heatwaves appear to be a significant contributor to the decline in the competitiveness and affordability aspects of energy security over the last five years.

**Possible threats to future energy security**

As discussed above, if retail electricity pricing for residential and small business consumers reflected the underlying costs, then better trade-offs between reliability, on the one hand, and competitive, affordable and sustainable electricity supplies, on the other could be possible. Because these prices are not cost reflective there may have been excess power system security investment relative to the risk of supply shortfalls and outages.

Substantial retail electricity price rises compared with prices in the broader economy are encouraging consumers to increase energy efficiency and investment in alternative sources of electricity, notably rooftop PV and other forms of distributed generation. As a consequence, both maximum (MW) and annual demand (MWh) are falling in many parts of the NEM.

Falling demand has in turn contributed to the economic stranding and withdrawal of nearly 4000MW of generation capacity. This is equivalent to more than nine per cent of total NEM generation capacity.

It is possible that a significant portion of network infrastructure is also economically stranded. Due to the regulation of network prices, decreases in demand have led to an increase in per unit prices. While consumers do not pay for stranded generation, under the current NEM rules for the economic regulation of networks, they continue to pay for any
stranded network infrastructure. As a consequence of rising unit network prices, the attractiveness of alternative options may increase and demand could be reduced yet further.

The sustainability component of energy security is forward looking. The test is whether internal and external pressures are effectively mitigated, and future vulnerabilities are identified and managed. The developments identified in this report suggest parts of the sustainability aspect of energy security may be at risk.
1. Introduction

Sapere has been retained by the Australian Department of Industry (the Department) to prepare a report on the impact of extreme weather events on the National Electricity Market (NEM), to inform the Department’s preparation of a third National Energy Security Assessment (NESA). The central question to be addressed is:

*Will the security of the NEM physical and market operations be affected by the increased severity, frequency and duration of heat-wave events in the short to medium term?*

The project has two parts:

- Part one consists of an analysis of data and reports on extreme weather events, including but not limited to heatwave events, since the formal start of the NEM in 1998. The aim is to review the type, number and frequency of past extreme weather events, analyse the outcomes, and use these findings to inform the second stage of the study.
- Part two consists of the development of a “stressor” scenario to assess the resilience of the NEM’s physical and market operations during prolonged, extreme heat-waves over the short- to medium-term (up to five years), with a focus on the influences of an increasingly diversified generation mix.

Sections two and three of this report relate to Part one. Sections four and five relate to Part two. Section six draws both parts together to develop general conclusions and findings. Additional supporting material is provided in the Appendix, including a summary description of all of the identified major EWEs.

For the purposes of this report, energy security is defined as the reliable, sustainable, and competitive availability of energy to support Australia’s economic, social and natural environments.

A **reliable** energy system provides energy with minimal disruptions; supply is adequate to support economic and social activities; systems, operations and processes are dependable; governance and regulation measures are trustworthy; market conditions are stable and consistent.

A **sustainable** energy system is forward-looking and innovates to address changing circumstances; it plans for unexpected events and mitigates internal and external pressures; it supports social and environmental aspirations; vulnerabilities are identified and managed.

A **competitive** energy system provides energy at an affordable price that does not adversely affect the competitiveness of the economy, and supports continued investment in the energy sector.

The current NEM reliability standard set by the Reliability Panel is measured in terms of maximum expected unserved energy (USE). Since the NEM was formed in 1998, the reliability standard has been set at 0.002 per cent per region or regions per year. This means that out of 100,000MWh of demand, no more than 2MWh of outage should be allowed in any given year.
The NEM reliability standard defines reliability incidents for generation and bulk supply. Although severe weather disruption of the grid at the distribution level can be significant, affecting wide areas for reasonable periods of time, this impact is local. Generally, large numbers of consumers are only affected by localised extreme weather in high density urban areas. Similarly, the focus of this report is on bulk supply relative to demand.

Expert analysis of global and Australian historical climate data indicates that the incidence and severity of extreme weather events has already increased in recent decades. These extreme weather events include extreme heat wave events, extreme precipitation events and extreme cyclone (wind events). In Australian conditions, there is a higher frequency and severity of conditions conducive to bushfires.

The analysis of climate data undertaken for this report also indicates that over the period since 1998 the number of extreme heatwaves has steadily increased. There were 1.2 heatwave events per annum in the first five year period, 2.4 in the second and 3.0 in the third. In addition, the number of extreme heatwave days increased from 15 for 1999-2003 to 26 for 2009-2013.

Expert climate analysis suggests that further global warming implies the future rate of increase in both the frequency and severity of extreme weather events, including heatwaves, will substantially exceed the historical rate of increase in frequency and severity. This reflects a structural change in the risk profile for these events.

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2. Framework, scope and data for historical analysis

2.1 Introduction

Extreme weather events of potential interest are approached from both meteorological and power system perspectives. This enables the identification of both these types of events, their significance to energy security, and to the points where the two intersect.

An iterative identification process produced a core list of 54 extreme weather events and their associated power system impact, detailed in Table 12 in Appendix 1. This process involved:

- identifying potential extreme weather events of interest from meteorological and emergency management data;
- identifying environmental threats to the power system, and significant power system events with environmental causes from AEMO reviewable operating incidents reports and reclassification data;
- excluding localised events unlikely to have widespread impact on the power system, while including extensive heatwaves;
- where extreme weather events were not already associated with power system events, obtaining AEMO daily operating reports to identify supply-side power system issues (loss of generation, load or reserve); and
- identifying where localised heatwaves not associated with supply-side issues are nonetheless associated with peak demand and/or prices.

Some other groups of events, such as all local severe heatwaves, are considered for context. The period of events of interest is generally 1998 to May 2014. The availability of power system data prior to 2007 is more limited. The following discussion elaborates on the significance of extreme weather events from metrological and power system perspectives.

2.2 Extreme weather events

From a meteorological perspective there are no general definitions of extreme weather events (EWE) as distinct from severe weather events. The ‘extremity’ of severe weather is largely related to its impact on human society (and to a lesser degree the environment in general, e.g. widespread bushfires).

---

7 By the definition of heatwaves discussed below, heatwaves are local events based on temperatures measured in capital cities, so at this stage concurrent heatwaves in adjacent NEM regions are separate events.

8 Hence, for example, a heatwave in starting in South Australia and moving across Victoria and Tasmania is identified as a single event.
Candidate events have been identified from Bureau of Metrology (BoM) and Australian Emergency Management (AEM) data from 1998 to May 2014. BoM temperature data has been used to identify significant heatwaves. Severe bushfires, storms, cyclones and other events have been identified from the AEM Knowledge Hub database, including events where significant deaths, injury or property losses occur.

**Definition of a heatwave**

A heatwave is typically defined as a period of excessively hot weather. As heatwave events in Australia, America and Europe have become increasingly associated with poor health and heightened mortality there has been increasing interest in developing a robust definition of a heatwave and the severity of heatwaves.

The BoM has been developing a robust method for defining, and hence forecasting and warning of such events, and piloted heatwave forecast map service in the summer of 2014.\(^9\) This applied an emerging definition of severe heatwaves developed by the Centre for Australian Weather and Climate Research (CAWCR, a partnership of CSIRO and BoM).\(^10\) This metrological approach, suitable for forecasting, aligns with historical studies based on health outcomes.

The emerging definition combines the concept of excess heat, the build-up of heat over a three day period measured relative to the 95\(^{th}\) percentile of historical data, and heat stress that arises from a period where temperatures are hotter, on average, than the recent past, say one month. This accommodates both the stress induced by hotter temperatures and the acclimatization to higher temperatures over an extended period.

The combined effect of excess heat and heat stress measured in this excess heat factor (EHF) provides a comparative measure of intensity, load, and duration of a heatwave event. The EHF is positive when a heatwave is in progress meaning the three-day period is hot in an absolute sense, being in the top 5\(^{th}\) percentile of temperature range, and additionally large when the three-day period is substantially warmer than the preceding month.

Using the EHF metric, definitions can be provided for heatwave events:

- A heatwave is a period of at least three days where the combined effect of excess heat and heat stress is unusual with respect to the local climate (EHF is positive).
- A severe heatwave is an event where EHF values exceed a threshold for severity that is specific to the climatology of each location (85\(^{th}\) percentile of the distribution of positive EHF values).
- An extreme heatwave is an event where EHF values are well in excess of the severity

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\(^10\) John Nairn and Robert Fawcett, Defining heatwaves: heatwave defined as a heat impact event servicing all community and business sectors in Australia, CAWCR Technical Report No. 060, The Centre for Australian Weather and Climate Research (CSIRO and the Bureau of Meteorology), March 2013
threshold.

While the definition of a severe heatwave is numerically precise, the definition of an extreme heat wave is not. Comparison of international extreme heat waves shows peak EHF two to four times the severe threshold.  

In the current study we have used temperature data for capital cities, combined with the local severe heatwave threshold (LSHT) given by CAWCR\textsuperscript{12}, to calculate the EHF metric expressed as a multiple of the LSHT, or ‘EHFx’ (i.e. a value of 1.0x is at the LSHT).

Considering each State as a separate event, from the 108 severe heatwaves between January 1999 and March 2014, 5 per cent are higher than 4.0x, 31 per cent are higher than 2.0x and 33 per cent are greater than 1.9x LSHT. For present purposes an EHFx greater than 1.9x LSHT is indicative of an extreme heatwave.

2.3 Environmental risks to the power system

2.3.1 Overview

The NEM transmission network is the largest continuous electricity grid in the world, by extent. It encompasses a number of climate zones from a tropical environment in Far North Queensland, warm and mild temperate climates in southern continental States, to cool temperate climate in Tasmania and mainland alpine regions.

Due to its extent, no historical Extreme Weather Events (EWE) have simultaneously affected all regions of the NEM. This substantially improves the systemic resilience of the grid because transmission interconnectors between regions enable the transfer of reserve capacity (security) and energy to regions that are under stress.

On the other hand, the long and often remote nature of transmission and interconnectors exposes bulk supply to environmental risks. In addition, outages in one region can sometimes cause shortfalls or outages in other regions.

Severe weather that is localised, remote and generally of low impact either economically or on human populations can be acutely threatening to grid critical infrastructure. In particular, electrically energized infrastructure is susceptible to lightning strikes and bushfires underneath lines. Consequently, the AEMO specifically monitors lightning and bushfires and continuously assesses threats to grid assets.

\textsuperscript{11} Page 23, op. cit.
\textsuperscript{12} Table 3, page 20 op. cit.
Figure 3 NEM transmission grid


2.3.2 Power system events

The NEM is operated within reliability and security standards set by the governance of the power system, and specifically the Reliability Panel operated by the Australian Energy Market Commission. Every year there are hundreds of power system events of greater or lesser consequence for reliability and security.
Business-as-usual is to operate the system to deliver system load reliably and securely even with the loss of any single generation, transmission or load element in each region. Loss of any single element is defined as a credible contingency event. These make up over 90 per cent of the total number of contingency events in the power system.

Simultaneous loss of more than one supply element is by definition a non-credible contingency event. On average each year 44 non-credible contingency events qualify as reviewable operating incidents (ROI) for investigation by AEMO (see box below).

In March 2014 AEMO published Statistics of Operating Incidents analysing 314 reviewable operating incident reports from 2007 to 2014. Twenty one per cent have a primary cause identified as environmental, two thirds of which (14 per cent) are due to lightning.

### Reviewable Operating Incident Reports

As required by the National Electricity Rules (NER) Clause 4.8.15 and the guidelines established by the Reliability Panel, AEMO conducts investigations of 'unusual power system events' within the NEM. These events are known as ‘reviewable operating incidents’ and are generally not considered as ‘credible contingency events’. As such, these events are not normally taken into account in the operation of the NEM.

AEMO conducts these investigations to assess the adequacy of the provision and response of facilities or services, and the subsequent appropriateness of actions taken to restore or maintain power system security. AEMO then publishes a report on each incident. AEMO classifies each ROI according to event type, primary cause and level of impact.

Classifications of cause include a range of equipment failure, control and procedural classes and two ‘environmental’ classes, one for lightning strike and one for other environmental issues.

Classifications of impact are rated by loss of load or generation:

<table>
<thead>
<tr>
<th>Impact</th>
<th>Explanation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nil</td>
<td>No loss of load or generation</td>
</tr>
<tr>
<td>Not Significant</td>
<td>Loss of load or generation less than 50MW</td>
</tr>
</tbody>
</table>

13 Higher mandated security (redundancy) standards apply in many parts of the NEM, in particular to ensure transmission access by major generation or to maintain supply to major load centres including aluminium smelters and central business districts.

14 Note that AEMO does not collate data about credible contingency events.

15 Examples include a single conductor or transformer on a transmission line, or a single generating unit.


18 The Reliability Panel Guidelines were reviewed in 2012 with the intention to focus investigations on incidents of significance to the operation of the power system. One of the key changes was the introduction of ‘critical transmission elements’, those above 220 kV or lower voltage that have been identified by AEMO as critical for the supply of electricity in or between regions.
Significant | Loss of load or generation exceeding 50MW but less than 250MW  
Very Significant | Loss of load or generation exceeding 250MW

Under certain circumstances, such as lightning or bushfires in the vicinity of critical equipment, non-credible contingency events may be recognized as distinctly possible (if not probable). In such cases these possible events may be reclassified as credible contingency events—so called power system reclassification events. When an event is reclassified the power system must be configured to maintain system reliability and security in the eventuality the event does occur. Hence reclassification data provide an indicator of power system management decisions to ensure resilience in the face of environmental threats.

**Power system data provided by AEMO**

AEMO data includes publicly available demand and price data and published reports. In addition to these, the AEMO provided several sources of additional data to support the identification and investigation of the core list of extreme weather events for this project and listed in Appendix 1. These included:

- Data summaries underlying the analysis in *Statistics of Operating Incidents*;
- AEMO publishes biannual reviews of power system reclassification events, including tables of events in the six month review period. In addition, the AEMO provided the total table of reclassification events over six years to May 2014.
- ROI reports for all the incidents included in *Statistics of Operating Incidents* as well as those coinciding with additional EWE dates identified were provided. Prior to 2007 some ROI reports were unavailable.
- Where no ROI reports were available, the AEMO provided Power System Operator Manager’s Daily Reports – where available. This report logs power system and market events, in particular frequency management and power system security events and actual and forecast lack of reserve conditions.

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19 Some ROI are reclassified during their investigation until their cause and the likelihood of reoccurrence is understood. This means that the power system is operated as if ROI would reoccur even if it is later determined that reoccurrence is unlikely.
3. Results of historical analysis

3.1 Introduction

This section summarises the results of the historical analysis of extreme weather events and power system events. The first part focuses on the impact of extreme weather events on the security of NEM physical operations (supply). The second part focuses on the impact of extreme weather events on the security of NEM market operations (cost).

3.2 Intersection of extreme weather and power system events

The findings with regard to extreme weather-power system events, while significant, constitute a minority of events considered potential or actual threats to the reliability and security of the power system. The core list of 54 EWEs between January 1999 and May 2014 identified in Appendix 1 overlaps with approximately 660 significant power system events in the same period.

The overlap of extreme weather events and power system events is illustrated in Figure 4. Significant power system events, represented by reviewable operating incidents, overlap with recognised environmental threats to the power system, represented in part by reclassification events. Significant power system events are further subdivided by their impact on the power system being significant or insignificant.

In a rough hierarchy of events, in order of decreasing power system significance and relevance, there are:

1. EWE causing ROI with load shedding and unserved energy;
2. ROI with load shedding and unserved energy independent of EWE;
3. EWE causing ROI without load shedding;
4. ROI without load shedding independent of EWE;
5. EWE threats prompting reclassification events;
6. Environmental threats that are not EWE prompting reclassification events; and
7. EWE of no significant consequence for the power system (at generation and transmission level).

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20 See discussion on “reclassification” events in Section 2.3.2 above.
Figure 4 Intersection of extreme weather and power system events

The intersection of extreme weather and power system events is shaded identifying the three main EWE groups listed above.

<table>
<thead>
<tr>
<th>Reviewable Operating Incidents</th>
<th>No significant or nil Impact</th>
</tr>
</thead>
<tbody>
<tr>
<td>Extreme Weather Events</td>
<td>1</td>
</tr>
<tr>
<td>Environmental threats to the power system</td>
<td>3</td>
</tr>
</tbody>
</table>

The proportions of all ROI and reclassification events based on six years of data are shown in Figure 5.21

Figure 5 Broader ROI and reclassification events

<table>
<thead>
<tr>
<th>ROIs</th>
<th>Reclassification Events</th>
</tr>
</thead>
<tbody>
<tr>
<td>31%</td>
<td>Lightning 93.7%</td>
</tr>
<tr>
<td>12%</td>
<td>Bushfire 1.9%</td>
</tr>
<tr>
<td>48%</td>
<td>Other 4.6%</td>
</tr>
</tbody>
</table>

The majority of ROI (79 per cent) have primary causes identified as customer, transmission or generator equipment failures, protection and control issues, operating errors or inadequate processes. A total of 21 per cent have a primary cause identified as environmental, two thirds of which (14 per cent) are lightning. Bushfires account for most of the ‘other environmental causes’ category (in one instance the cause was vermin).

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21 Proportions based on the data from 2007 to 2014 reported in the AEMO report, Statistics of Operating Incidents, 31 March 2014, and the table provided by AEMO of reclassification events over six years to May 2014.
A sizable minority of ROI (43 per cent) have significant or very significant impact on the power system. ROI with both environmental causes and significant or very significant impact on the power system constitute 12 per cent of all ROI.

Nearly all of the 1,973 reclassification events over six years to May 2014 were due to lightning, and just 1.9 per cent due to bushfires. Reclassification events due to lightning are more prevalent in summer months; three quarters of these events occur between October and March. Of these 1,973 events, just 16 lightning strikes and no bushfire threats were actually realised.

3.3 Extreme weather-power system events

3.3.1 Timeline of extreme weather events that affected the NEM

There have been 54 EWE’s between January 1999 and May 2014. Figure 6 illustrates the occurrence of these EWEs. Appendix 1 provides greater detail of these events. Multi-State extreme heatwaves and single State heatwaves associated with demand peaks each make one quarter of these events. Bushfires represent 21 per cent of EWEs. Together, severe storms, floods and cyclones make up the remaining 28 per cent of identified EWEs.22

Figure 6 Timeline of extreme weather events

This timeline indicates a higher frequency of these events in the latter half of this period relative to the first half. This may, however, reflect variation in the availability of power system data before and after 2007 and not a real trend.

Figure 7 illustrates a timeline based wholly on meteorological data for heatwaves. This is based on the total number of heatwaves with a maximum excess heat factor as severe (EHFx >1.0) and extreme (EHFx > 1.9). Concurrent heatwaves in separate capital cities are treated as distinct.

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22 Wet/cold events are depicted below the line to aid interpretation.
While the average number of severe heatwaves per 5-year period is stable (4.4 to 4.6), the number of extreme heatwaves has steadily increased (from 1.2 to 2.4 to 3.0). In addition, the number of heatwave days (days with an EHFx indicator above the severe/extreme thresholds) has increased from 15 for 1999-2003 to 26 for 2009-2013. This is consistent with expert analysis of global and Australian historical climate data indicating a trend of increasing incidence and severity of extreme heatwaves.\textsuperscript{23}

### 3.3.2 Impact of extreme weather-power system events

As noted in Figure 5, power system events of environmental origins and significant impact constitute only 12 per cent of reviewable operating incidents. An overview of the impact of the 54 EWEs on the power system is given in Figure 8. Of these:

- only 16 EWE or 30 per cent led to ROI; and
- 12 of those 16 events have significant or very significant impact as classified by AEMO.

Figure 9 quantifies the impact of the EWE in Figure 8 on the power system classified as significant or very significant (noting that data is infrequently available prior to 2006). This includes lost generation (LG in MW), lost load (LL in MW) and, where reported or estimable, unserved energy (USE in MWh).

\textsuperscript{23} See for example Australian Climate Council and the IPCC Fifth Assessment Report
The events associated with the most lost load and unserved energy were seven bushfires and two heatwaves. Three events associated with USE in excess of 1000MWh include:

- The 2007 Great Dividing Complex fires and severe heatwave. This caused the largest lost load and USE by triggering a separation between Snowy and Victoria and subsequently Victoria and South Australia, triggering under-frequency load shedding (UFLS).
- The January 2009 ‘1 in 100’ year South East Australia extreme heatwave. This led to the Black Saturday bushfires and involved a series of significant power system events over several days in both Victoria and South Australia. The heatwave lack of reserve conditions included the partial separation of Melbourne from significant generation sources and interconnectors.
- The January 2001 NEM islanding event. Triggered by grass fires in severe weather conditions, NSW and Victoria were separated, with cascading control and frequency control load shedding.

Three other bushfires and an extreme heatwave across Tasmania, Victoria and South Australia in 2007 are associated with very significant lost load and/or generation, but generally no quantified USE. More recently, EWEs such as the 2013 Angry Summer, the October 2013 Sydney/Blue Mountains bushfires and January 2014 heatwave have had no or negligible impact on NEM physical or market operations.

In contrast to heatwaves, ‘wet’ weather events generally have no significant impact on NEM bulk supply. For example, although Cyclone Yasi damaged seven transmission lines, both load and generation were substantially reduced in advance of the cyclone’s landfall and no load was lost or interrupted.24

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24 Demand was reduced due to business closures and some distribution outages before landfall. Some generation was powered down along with two substations.
Figure 9 EWE with significant/very significant power system impact

1. Neither ROI nor Daily Reports were available for the period associated with the 2003 Victorian Alpine Region and Canberra bushfires that formed the largest conflagration since 1939 Black Friday bushfires and resulted in four deaths and hundreds of destroyed homes in Canberra. Given the location it is likely these bushfires threatened some critical transmission and interconnector assets.

2. In the 2007 bushfire-islanding event load restoration commenced 40 minutes after the incident and final load was restored after 3 ¼ hours. An estimate of USE at 7300MWh is provided in the introduction of the ROI report - no guide as to how this was calculated is included in the report.
The largest impact resulting from flooding in Gippsland was indirect. During extensive flooding in the Latrobe Valley, the failure of the levee bank of the Morwell River diversion flooded Yallourn coal mine. This disrupted coal conveyers and therefore limited Yallourn’s output for nearly a month.

The impact of even the Gippsland flood is exceeded by the strongest earthquake recorded in Victoria for three decades. The quake struck near Moe at 8.55 pm on 19 June 2012, at a shallow depth of 9.9 km. Multiple generators in Victoria (Loy Yang and Snowy) and South Australia (Torrens Island) tripped amounting to the loss of approximately 1955 MW of generation and 400 MW of load in Tasmania and Victoria.

**Power system events in Victoria and South Australia**

As noted in Section 2.3.2, power system events with environmental causes are a minority of events with significant and very significant impact, and such events are a minority of all ROI. To place the impact of extreme weather-power system events in context, regarding ROI in Victoria and South Australia: 26

- there were 19 incidents of significant impact and 12 of very significant impact for ROI with non-environmental causes;
- there are seven incidents of significant impact and four of very significant impact for ROI with environmental causes (the 2007/2009 bushfire/heatwave events comprise six and two of these events respectively);
- for ROI with non-environmental causes,
  - an average 186MW and maximum 330MW load was lost, and
  - an average 227MW and maximum 753MW generation was lost;
- the 2007 separation event had the largest impact in terms of MW lost and duration (USE); and
- there were separation events in 2009 and 2012 with nil impact.

### 3.3.3 System demand and extreme weather

**Demand during hot weather EWE**

There is a strong correlation between extreme hot weather events and peaks in demand. Annual maximum demand (AMD) typically occurs during summer extreme heatwaves in all States of the NEM except Tasmania where AMD occurs during winter.

Figure 10 illustrates the extent peak demand varies with the excess heat factor measure of heatwave severity for all local heatwaves in the study period. The key point highlighted in Figure 10 is the more severe the heatwave, the more likely demand approaches AMD. For

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91 per cent of extreme heatwaves, peak demand is more than 90 per cent of AMD. This compares with severe heatwaves where 76 per cent of events exceed 90 per cent of AMD.

The maximum excess heat factor of each heatwave is expressed as EHFx, the multiple of the local severe heatwave threshold, with lines showing the severe heatwave threshold and indicative extreme heatwave threshold for the top third of severe heatwave events. As LSHT is particular to the local environment, heatwaves are also distinguished by NEM region.

**Figure 10** Demand and heatwave severity (January 1999-April 2014)

1. **Note:** Annual maximum demand is reached in summer in all NEM regions except Tasmania.

The complexity of peak demand during local heatwaves is not clearly visible in Figure 10. Figure 11 provides the count of heatwaves for each State in bands of demand approaching annual maximum demand.

This illustrates some of the climate differences between capital cities, as well as varying implications for peak demand.\(^{27}\) The key points of Figure 11 include:

- Heatwaves are a general driver of demand in all mainland states, with over 80 per cent of demand peaks during heatwaves above 90 per cent of annual maximum demand.
- Heatwaves are particularly demand drivers in South Australia, Victoria and Queensland, where a significant majority of demand peaks during heatwaves are in the top 5 per cent of annual maximum demand.
- Heatwaves are particularly important in South Australia, which has both the most heatwave events (more than double those in NSW), and more extreme demand events (the top 1 per cent of AMD) associated with heatwaves.

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\(^{27}\) Demand and other NEM data are by NEM region. Temperature data is local and in this case capital city weather stations represent regions/States and Territories.
3.4 Impact of extreme weather on NEM markets

The previous section discussed the impact of extreme weather on the physical NEM. The remainder of this section focuses on the impact of extreme weather on NEM markets. This also relates to economic aspects of reliability, as well as competitiveness and affordability, aspects of energy security, as defined in Section One.

An economic metric for reliability is the value of customer reliability (VCR). VCR is the direct dollar economic impact of loss of electricity supply where this is attributable to the loss of bulk supply. The latter part of the discussion below discusses the impact of extreme weather on NEM markets, focusing on wholesale and network costs, as well as consumer bill impacts.

3.4.1 Cost of peak demand related to hot weather events

Figure 11 above established that heatwaves are a major driver of demand peaks. The relationship between hot weather events and daily demand is extended to NEM spot prices in Figure 12. The events depicted include all bushfires, local heatwaves and local hot days in excess of 40°C in the period 1999 to 2014.28

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28 These are preliminary groups of metrological events utilised in the initial stage of identifying the final master list of 54 EWEs.
There is a high frequency of hot weather events with price spikes peaks that exceed $300/MWh. Key points of note include the following.

- 52 per cent (12) of major bushfires led to price spikes. 26 per cent (six) of major bushfires were associated with demand peaks.
- 71 per cent (79) of local severe and extreme heatwaves led to price spikes. 73 per cent (82) of these had demand peaks.
- 71 per cent of local hot days (90) led to price spikes. 57 per cent (94) of those in excess of 40ºC had demand peaks.

In addition to representing the operational limit of the power system, AMD is a key driver of the overall cost (and hence affordability) of secure electricity supplies – as well as the risk of USE. Figure 12 provides an indication of the frequency of peak wholesale prices during peak demand events. Figure 11 provides an indication of the association of heatwaves and the top centile of annual maximum demand, a major driver of network costs.

### 3.4.2 Cost of demand during cold/wet weather EWE

Figure 13 presents the relationships of peak demand and peak NEM spot price (similar to Figure 12) for cold/wet weather events including severe storms, cyclones, hail and floods. The frequency of these events is far lower than “hot” events. Moreover, few “cold” events are associated with either peak demand or price, and none with AMD. Of “cold” extreme weather, cyclones most frequently coincide with demand and price peaks.

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29 As with hot weather events, these are preliminary groups utilised in the initial stage of identifying the final master list of 54 EWEs.
The event analysis above highlights the strong correlation between high temperatures, especially heatwaves, demand peaks and price peaks. This relationship is further illustrated in Figure 14 for a specific EWE, in this case the 2009 SE Australia extreme heatwave in South Australia.

The pattern for this specific example applies equally to other years and other States (excluding Tasmania where AMD occurs in winter). Demand peaks generally fall after a period of high maximum temperatures, and higher demand peaks and AMD occurs when night-time temperatures are also elevated. Likewise, price spikes often occur during days of high demand.

The effect of heatwaves on NEM wholesale prices is significant. The impact can be estimated from the impact on volume weighted wholesale prices of trading intervals greater than $300/MWh. Over summer, prices above this threshold are often associated with heatwaves. While representing only a small number of trading intervals in a year, wholesale price spikes represent contribute 26 per cent of South Australia wholesale prices and 14 per cent of Victorian wholesale prices in a typical year, based on data for 2000 to 2014.
Figure 14 High demand in South Australia in 2009

This chart shows a period 30 days before and after the day of annual maximum demand for 2009.

1. Daily maximum demand expressed as a percentage of annual maximum demand (AMD); daily maximum price expressed as a percentage of market price cap (MPC).

The network component of electricity supply costs is broadly similar in scale (for a typical small consumer) to the wholesale cost component. The impact of extreme heatwaves on incremental network costs also needs to be considered.

The added cost of network capacity can be estimated from utilization above 90 per cent of maximum reliable capacity during extreme heatwave events. This capacity is typically utilised for a fraction of one per cent of the year, and often entirely during a single extreme heatwave event.

Ten per cent of regulated annual revenue can be attributed to the cost of the last 10 per cent of required capacity, and then allocated in proportion to the number of ½ hour intervals above 90 per cent AMD. This is 98 and 94 per cent respectively in Victoria and South Australia in the case of the 2009 heatwave, 86 and 75 per cent respectively in the case of the 2014 heatwave. The results are given in Table 1 below.

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30 This is a simplification and does not take into account possible differences in network capacity costs over time and as capacity approaches maximum demand. See further discussion on network costs in Appendix 2.
Table 1 Network cost of key extreme heatwaves ($million)

<table>
<thead>
<tr>
<th>Network regions</th>
<th>Annual regulated revenue</th>
<th>10% annual revenue</th>
<th>2009 heatwave</th>
<th>2014 heatwave</th>
</tr>
</thead>
<tbody>
<tr>
<td>Victoria (6 networks)</td>
<td>2,246</td>
<td>224.6</td>
<td>220</td>
<td>187</td>
</tr>
<tr>
<td>South Australia (2 networks)</td>
<td>780</td>
<td>78.0</td>
<td>73</td>
<td>57</td>
</tr>
</tbody>
</table>

3.5 NEM economic impacts

Estimating the NEM cost impact of extreme weather events is complex and in addition is likely to vary depending on network area and a range of other factors. There are three main areas of interest:

- The impact on NEM infrastructure ownership, operations and maintenance costs;
- The direct economic cost to consumers of supply outages – indicated by a VCR metric; and
- The impact on power bills.

3.5.1 Economic cost of supply outages

Supply outages impose substantial economic costs. If the value of customer reliability (VCR) were $20,000.00 per MWh, then the cost of a 1000MW outage for 30 minutes would be $10m. On this basis, VCR for the three greatest USE events is:

- $46m for the 2009 South East Australia extreme heatwave;
- $34.7m for the 2007 Great Dividing Complex fires and severe heatwave; and
- $30m for the 2001 bushfire triggered islanding event.

The Black Saturday bushfires, with $5m VCR, are the next largest EWE that resulted in USE.

The AEMO is reviewing estimates of the Value of Customer Reliability for power system planning purposes. Estimating VCR is complex and estimates vary substantially.

In some cases, VCR is related to the incremental cost of alternative electricity supplies. This is the case for facilities that have their own back up generating systems. Rooftop PV facilities need to be shut off or islanded from the grid to avoid safety risks from energising otherwise de-energised distribution networks.

More readily quantifiable costs can include loss of business revenue. For example, a business may be forced to close or otherwise lose business (cash only transactions). Other costs include loss of stock, for example the contents of supermarket freezers. Yet other costs might include inability to maintain critical operations, for example a milking, harvesting or other process.
Costs that are more difficult to quantify include threats to public health and safety. Notable examples include life support machines, security systems and home or business water and sewage pumping systems. During extreme heatwaves, the loss of cooling systems may cause severe health problems and possibly lead to higher mortality rates.

Economic impacts of supply outages for the operation and wellbeing of households and families are especially difficult to quantify. Impacts will vary depending on the time of day and other factors. It is possible that costs to households will be substantially higher during extreme heatwave and high bushfire risk events.

### 3.5.2 Impact of extreme heatwaves for power bills

The Productivity Commission has found that peak demand, especially during extreme heatwaves, adds $350 per year to power bills:

> ‘…a household running a 2kilowatt (electricity input) reverse cycle air conditioner, and using it during peak times, receives an implicit subsidy equivalent of around $350 per year from other consumers who don’t do this.’

The PC estimate refers to infrastructure costs – network and generation capacity. It also excludes any costs associated with loss of supply (VCR) that may be attributable to excess demand. In addition, if fuel costs, which are higher during peak periods, are included, the cost would exceed $350 per year.

This $350 per annum value is equivalent to between 22.2 per cent and 36.7 per cent of annual wholesale and network supply costs for a typical customer in the NEM. The variability reflects differences in typical annual consumption, network and wholesale costs.

The Productivity Commission estimate only covers infrastructure costs – network and generation capacity. If fuel costs and USE are included, the cost would exceed $350 per year. This suggests that costs attributable to extreme heatwaves could represent well in excess of a third of typical electricity retail supply costs and household bills.

The estimate is based in part on customer weighted average volume for NEM states. This was derived by combining benchmark data by household size weighted by Australian Bureau of Statistics (ABS) census data regarding typical household size. The resulting unit value is compared with the authors’ database of per-unit cost of supplying typical small residential or business consumers for each network area in the NEM.

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3.5.3 Possible impacts for infrastructure ownership, operation and maintenance costs

Extreme weather events could be associated with damage to electricity infrastructure and in some cases the loss of this infrastructure altogether. Examples include major equipment failures in specific generation or transmission assets.

Historical data on the incidence and size of any damage or destruction costs in the NEM were not sought or available in the course of the project. The discussion below refers to possible costs, drawing on broad experience and evidence from domestic and international energy sector distribution and bulk supply outages including gas supply outages.

If damage to or destruction of assets occurs, infrastructure owners will incur repair or replacement costs. Replacement implies incurring accelerated depreciation costs as well as the cost of the replacement assets. Asset replacement itself can lead to additional procurement costs, as well as the cost of operating interim solutions and work-arounds.

For generators, impaired or lost assets may impair capacity or availability (or both). This can lead not only to loss of revenue but also the crystallisation of financial liabilities under forward contracts. Where generators have offtake commitments to fulfil, they may be exposed to wholesale spot prices for any shortfall between the commitment and their production. While generators would seek to recover losses and other costs, this is constrained by competition. In some cases, generators may be unable to recover costs fully.

The very reduction in a major generator’s capacity/output may result in higher wholesale and forward contracts than otherwise. As a consequence of these developments, part of the costs from any impaired or lost assets may be a general increase in wholesale spot and forward contract prices. In this case there could be windfall gains for some (alongside windfall losses for others).

For transmission companies, in the event of a very large asset failure, existing regulated revenue caps may be insufficient to fund accelerated depreciation and procurement of additional assets. Where this occurs, a possible outcome is for future regulated transmission prices to increase.

Extreme weather events are likely to contribute to additional operations and maintenance costs. An immediate aspect is a need to maintain systems and resources required to monitor assets in the lead up to and during an EWE. Following an event, infrastructure owners may be required to undertake enhanced asset condition monitoring to ensure any and all associated damage has been identified.

Some damage or loss may be insurable, but this is not always the case. In any event, insurance costs are already likely to have been affected by risks from extreme weather events, along with other threats.
4. **Approach to scenario modelling**

4.1 **Introduction**

This section sets out the nature of a future heatwave scenario designed to identify some of the key variables that are likely to influence the reliability and security of the electricity system when it is under extreme stress. The heatwave scenario is drawn from a synthesis of the following elements:

- The relationships between heatwaves, demand, supply and other variables identified in the previous Section;
- The experience from the January 2014 heatwave affecting Victoria and South Australia; and
- Forecast supply and demand for the period to which the 2014 NESA applies, taking into account expected demand and supply trends, including a more diversified generation mix.

4.2 **January 2014 extreme heatwave**

The impact of the January 2014 heatwave is described in a special report prepared by the AEMO and dated 26 January 2014. The following represents a précis of that report.

Victoria and South Australia experienced record temperatures between Monday 13 January and Friday 17 January 2014. South Australia experienced the first ever five day period above 42°C while Victoria experienced the first ever four day period above 41 °C.

During the heatwave, Victoria and South Australia both experienced near-record demands on the NEM power system. The level of demand had not been experienced since a previous extreme heatwave in 2009, when record operational demands were set.

The NEM power system was able to supply demand at all times. Although minimum reserve levels were sometimes low, AEMO did not require any load shedding. Some small distribution level local outages were experienced due to distribution equipment failures.

A notable feature of the January heatwave was significant generation outages. These are summarised in...
Table 2 below.

As a result of the combination of high demand and supply outages, there were periods where the failure of any single generator, interconnector or transmission asset would have potentially resulted in load shedding.

Of particular concern was the operation of Basslink. Basslink has a temperature operating range of 36°C at the Tasmanian end and 46 °C at the Victorian end. Temperatures during the event were close to these limits.
Table 2 Supply outages during 2014 heatwave

<table>
<thead>
<tr>
<th>Asset</th>
<th>Duration</th>
<th>Cause</th>
<th>Implications</th>
</tr>
</thead>
<tbody>
<tr>
<td>Loy Yang A3 (Vic)</td>
<td>C2.5 days</td>
<td>Auxiliary supply problems</td>
<td>Loss of 560MW</td>
</tr>
<tr>
<td>Loy Yang B1, B2 (Vic)</td>
<td>4 days</td>
<td>Cooling problems</td>
<td>Output reduced from 1120MW to 680MW</td>
</tr>
<tr>
<td>Torrens Island B3 (SA)</td>
<td>21 hours</td>
<td>Boiler issue</td>
<td>Loss of 200MW</td>
</tr>
<tr>
<td>Basslink</td>
<td>One hour</td>
<td>Transformer temperature</td>
<td>Loss of up to 595 MW Victorian import capacity</td>
</tr>
</tbody>
</table>

Source: Sapere analysis of AEMO data

The loss of Basslink, which was transferring 500MW from Tasmania to Victoria, would have caused RERT contracts to be applied. This would enable 650MW of aluminium smelter pot lines in Victoria being curtailed for up to 90 minutes. If at any time the load shedding required to maintain system stability was greater than 650MW or longer than 90 minutes, shedding of Victorian and South Australia industrial, commercial and domestic customer loads may have been required.

Fire was a threat to a number of gas and electricity energy assets during the heatwave. A total of 17 separate fires were assessed as posing direct threats to energy infrastructure and were monitored closely.

In South Australia high wind generation displaced interconnector imports, to zero on 17th January. Solar PV deferred peak operational demand by up to 2½ hours in South Australia on 16th January. This deferral, along with the time zone difference between South Australia and Victoria, meant that maximum demand did not coincide in the two regions.

A notable feature of the 2014 heatwave is that operational demand was lower than during the 2009 heatwave. Relevant factors appear to include:

- In 2009, most schools had commenced. This was not the case in 2014;
- There is more embedded generation installed in 2014 than in 2009; and
- Temperatures were higher in 2014 than in 2009, but operational demand was slightly less.

The reduction in operational demand in 2014 compared with 2009 appears to be attributable to a combination of:

- Increased energy efficiency (avoided consumption);
• Increased supply from small non-scheduled generation (SNSG); and
• Increased supply from “behind the meter” supply, most notably rooftop PV.

Wholesale spot price volatility was observed across the market in Victoria, South Australia, and Tasmania, including frequent negative prices in Tasmania. Possibly as a result of lower operational demand, wholesale electricity prices in the 2014 event were lower than in the 2009 event.

As a point of reference for the development of the future scenario, Table 3 below provides a simplified snapshot of the overall supply demand balance at its tightest point during the January 2014 heatwave.

### Table 3 Supply-demand balance for January 2014 heatwave

<table>
<thead>
<tr>
<th>MW</th>
<th>QLD</th>
<th>NSW</th>
<th>VIC</th>
<th>SA</th>
<th>TAS</th>
</tr>
</thead>
<tbody>
<tr>
<td>Demand</td>
<td>6,862</td>
<td>11,846</td>
<td>10,240</td>
<td>2,978</td>
<td>1,135</td>
</tr>
<tr>
<td>Generation</td>
<td>10,691</td>
<td>15,406</td>
<td>9,562</td>
<td>2,966</td>
<td>2,503</td>
</tr>
<tr>
<td>Net imports</td>
<td>0</td>
<td>-95</td>
<td>678</td>
<td>12</td>
<td>-594</td>
</tr>
<tr>
<td>Operational balance</td>
<td>3,830</td>
<td>3,465</td>
<td>0</td>
<td>0</td>
<td>775</td>
</tr>
</tbody>
</table>

**Source:** Sapere analysis of AEMO data

This highlights the fact that both Victoria and South Australia were dependent on imports from other regions and hence that continued operation of interconnectors was crucial.

Table 3 refers to operational demand/generation. Native demand/generation is a broader measure. Operational demand includes all residential, commercial and large industrial consumption supplied from the grid. Native demand is operational demand plus the contribution from SNSG, which generally includes units with less than 30MW of capacity. SNSG may reduce demand as well as increase generation (via exports of any surplus). The operational balance is therefore more conservative than the native balance.

### 4.3 Heatwave scenario

A stressor heatwave scenario is assumed to occur over the period from 4 February to 8 February 2019. New record temperatures are assumed to occur in Victoria, South Australia and Tasmania, alongside very high temperatures in NSW/ACT and Queensland.
It is assumed that demand exceeds a 1 in 50 year event threshold in all three South Eastern States.\(^3\) This is a much more demanding threshold compared with the 1 in 10 year event threshold used by the AEMO in its demand forecast reporting.

A 1 in 10 demand forecast is used in South Australia. This reflects the 1- 2½ hour delay in the South Australia maximum demand required to calculate South Australia demand at Victoria’s maximum demand.

The scenario model calculates the net balance of capacity from demand forecasts for available forecast generation and interconnector capacity. The model does not attempt to model dynamic requirements for system reserve – zero net balances are considered indicative or potential low or lack of reserve conditions manageable within the options for system management.

All three AEMO demand scenarios incorporate an additional variable to reflect the increasing frequency and severity of extreme heatwaves. The 1 in 50 demand forecast is extrapolated from AEMO’s demand forecast by assuming a normal distribution between the series provided by AEMO. These are used for Victoria and Tasmania, where the peaks are expected to be synchronous.

Available generation includes all current and confirmed scheduled, semi-scheduled generators and non-scheduled generators over 30MW. The AEMO’s factors for firm summer availability are applied to semi-scheduled and non-scheduled wind and solar generation.

The interconnectors are modelled with a simple flow. First, the Victoria – South Australia flow required to meet South Australia demand, then the flow from Tasmania and NSW to support Victorian demand, net exports to South Australia. Finally, Queensland-NSW flow to meet NSW demand, net exports to Victoria. The maximum flows reflect nameplate summer time interconnector capacity. In addition, they are constrained to reflect network congestion during peak demand/generation.

Transmission interconnectors allow the importation of energy and generation capacity (reserves) into Victoria and South Australia, thereby reducing risks to reliability and supply in these two jurisdictions. High ambient temperatures, and a high probability of numerous bushfires, mean there is a significant likelihood interconnection capacity will be reduced or possibly lost altogether. Any loss of transmission capacity reduces capacity reserves, and could lead to the effective separation of Victoria and South Australia or both. Under these conditions, minimum capacity threshold reserves would be breached, there could be a risk of further outages and loss of supply while an islanded area or areas stabilise.

There is a high level of uncertainty over the distribution of outcomes under a future extreme heatwave stress scenario. In addition, to uncertainty over both structural and event related demand, there is also uncertainty over a range of other operational factors, such as the performance of key generation, transmission and other infrastructure under a future extreme heatwave.

\(^3\) Although as with the January 2014 event, maximum demand in Victoria and South Australia are assumed not to coincide.
These uncertainties are assessed by comparing a number of alternative supply and demand scenarios, including:

- Forecast maximum demand in February 2019 under three scenarios set out in the AEMO’s 2014 National Energy Forecast Report (NEFR);
- Available generation capacity and whether offline generation is brought back into service;
- Various combinations of coal generation outages;
- Variable output from wind generation;
- Any constraints on or loss of capacity for the following key interconnectors:
  - NSW -> Victoria
  - Tasmania -> Victoria
  - Victoria -> South Australia.

4.4 Forecast demand for summer 2018/19

The most recently available AEMO forecast of operational demand for the summer of 2018/19 was published on 16th June 2014. The most notable feature of the 2014 forecast for present purposes was that forecast demand for 2018/19 was significantly revised downward compared with the 2013 NEFR.

The historical and forecast continuing decrease in forecast demand (excluding Queensland Liquefied Natural Gas) is attributed to:

- A decline in energy intensive industries, such as the closure of the Point Henry aluminium smelter in Victoria;
- Strong growth (23.6 per cent annually) in rooftop PV installations, particularly in Queensland and Victoria; and
- Strong growth (10 per cent annually) in total energy efficiency savings, with key contributions from air-conditioning, refrigeration and electronics.

Due to the substantial reductions in forecast demand in the medium scenario, as discussed earlier, other things being equal, the overall supply demand balance would be more favourable in February 2019 compared with January 2014. Accordingly, for the purpose of developing a stressor scenario, the AEMO’s high demand scenario has been applied to the February 2019 heatwave scenario.

The AEMO high demand scenario is not regarded as a likely scenario. It is based on substantial increases in general economic activity and a stalling of some significant recent energy efficiency and grid substitution NEM trends. It is therefore appropriate to apply this AEMO scenario for the purpose of a stress extreme heatwave scenario.

Table 4 below summarises assumed operational demand in the 2019 stress scenario compared with the 2014 heatwave. The key point is that maximum demand in Victoria in a 1 in 50 year scenario is forecast to be no more than 14 per cent higher (Victoria) than it was during the 2014 heatwave. The increase in maximum demand in these two regions is much lower compared with other regions. For the most part this reflects relatively slow economic and population growth, along with a decline in traditional manufacturing, including aluminium and light vehicle manufacture.
Table 4 2014 and 2019 demand scenario comparison

<table>
<thead>
<tr>
<th>MW</th>
<th>QLD</th>
<th>NSW</th>
<th>VIC</th>
<th>SA</th>
<th>TAS</th>
</tr>
</thead>
<tbody>
<tr>
<td>Max demand Jan 2014</td>
<td>6,862</td>
<td>11,846</td>
<td>10,240</td>
<td>2,978</td>
<td>1,135</td>
</tr>
<tr>
<td>Max demand Feb 2019</td>
<td>10,127</td>
<td>15,049</td>
<td>11,029</td>
<td>3,391</td>
<td>1,579</td>
</tr>
<tr>
<td>Difference</td>
<td>3,266</td>
<td>3,203</td>
<td>789</td>
<td>413</td>
<td>444</td>
</tr>
<tr>
<td>Percentage</td>
<td>47.6%</td>
<td>27.0%</td>
<td>7.7%</td>
<td>13.9%</td>
<td>39.1%</td>
</tr>
</tbody>
</table>

Table 5 below compares assumed demand in the 2019 scenario with all-time record demand in each region. This highlights that the 2019 scenario for NSW, Victoria and South Australia is less than 5 per cent higher (Victoria) than the all-time maximum demand recorded.

Table 5 2019 demand scenario vs all time record demand comparison

<table>
<thead>
<tr>
<th>MW</th>
<th>QLD</th>
<th>NSW</th>
<th>VIC</th>
<th>SA</th>
<th>TAS</th>
</tr>
</thead>
<tbody>
<tr>
<td>All time demand record</td>
<td>8,897</td>
<td>14,744</td>
<td>10,576</td>
<td>3,399</td>
<td>1,446</td>
</tr>
<tr>
<td>2019 scenario</td>
<td>10,127</td>
<td>15,049</td>
<td>11,029</td>
<td>3,391</td>
<td>1,579</td>
</tr>
<tr>
<td>Difference</td>
<td>1,230</td>
<td>305</td>
<td>453</td>
<td>8</td>
<td>133</td>
</tr>
<tr>
<td>Percentage</td>
<td>12.1%</td>
<td>2.0%</td>
<td>4.1%</td>
<td>0.2%</td>
<td>8.4%</td>
</tr>
</tbody>
</table>

4.5 Assumed generation supply for summer 2018/19

As a result of falling operational demand, and strong wholesale market competition among generators, 3,928MW of generation capacity has been withdrawn since 2012. Of this, 2,298MW of capacity is offline but could be returned to service depending on future supply and demand conditions. Offline and shutdown generation capacity is listed in Table 6. This highlights that there has only been limited capacity withdrawn in Victoria. This may reflect the relative impact of cash payments and free carbon credits provided to high emissions generation, the bulk of which is located in Victoria.
Table 6 Offline generation capacity

<table>
<thead>
<tr>
<th>Power station</th>
<th>Type</th>
<th>Location</th>
<th>Summer capacity</th>
<th>Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tarong</td>
<td>Coal</td>
<td>Qld</td>
<td>700</td>
<td>Offline</td>
</tr>
<tr>
<td>Collinsville</td>
<td>Coal</td>
<td>Qld</td>
<td>190</td>
<td>Offline</td>
</tr>
<tr>
<td>Swanbank E</td>
<td>Gas</td>
<td>Qld</td>
<td>385</td>
<td>Offline</td>
</tr>
<tr>
<td>Wallerawang 7</td>
<td>Coal</td>
<td>NSW</td>
<td>500</td>
<td>Shutdown</td>
</tr>
<tr>
<td>Wallerawang 8</td>
<td>Coal</td>
<td>NSW</td>
<td>500</td>
<td>Offline</td>
</tr>
<tr>
<td>Munmorah</td>
<td>Coal</td>
<td>NSW</td>
<td>600</td>
<td>Shutdown</td>
</tr>
<tr>
<td>Morwell 3</td>
<td>Coal</td>
<td>Victoria</td>
<td>70</td>
<td>Offline</td>
</tr>
<tr>
<td>Morwell 2</td>
<td>Coal</td>
<td>Victoria</td>
<td>25</td>
<td>Offline</td>
</tr>
<tr>
<td>Northern</td>
<td>Coal</td>
<td>SA</td>
<td>540</td>
<td>Shutdown</td>
</tr>
<tr>
<td>Playford</td>
<td>Coal</td>
<td>SA</td>
<td>200</td>
<td>Offline</td>
</tr>
<tr>
<td>Pelican Point</td>
<td>Gas</td>
<td>SA</td>
<td>218</td>
<td>Offline</td>
</tr>
<tr>
<td><strong>Total offline</strong></td>
<td></td>
<td></td>
<td><strong>2298</strong></td>
<td></td>
</tr>
<tr>
<td><strong>Total withdrawn</strong></td>
<td></td>
<td></td>
<td><strong>3928</strong></td>
<td></td>
</tr>
</tbody>
</table>

Source: Sapere interpretation of AEMO data

The supply scenario for 2019 represents only modest changes in committed capacity compared with 2014 as a result of subsequent generation withdrawal. The changes are shown in Table 7 below. Only “committed” new generation projects incorporated into the AEMO’s 2013 Electricity Statement of Opportunities have been included in the 2019 Scenario.34 This means that the scenario is not sensitive to uncertainty over the outcome of the 2014 review of the Renewable Energy Target.

Table 7, 2014 vs 2019 firm supply capacity comparison

<table>
<thead>
<tr>
<th>MW</th>
<th>QLD</th>
<th>NSW</th>
<th>VIC</th>
<th>SA</th>
<th>TAS</th>
</tr>
</thead>
<tbody>
<tr>
<td>2014</td>
<td>10,691</td>
<td>15,406</td>
<td>10,562</td>
<td>2,966</td>
<td>2,503</td>
</tr>
<tr>
<td>2019</td>
<td>11,130</td>
<td>15,456</td>
<td>10,819</td>
<td>2,833</td>
<td>2,528</td>
</tr>
<tr>
<td>Difference</td>
<td>438</td>
<td>50</td>
<td>256</td>
<td>-133</td>
<td>25</td>
</tr>
</tbody>
</table>

34 Committed projects excludes proposals for new generation that are subject to engineering, environmental and market feasibility testing and are yet to achieve financial close. The AEMO published its 2014 ESO after the completion of the scenario analysis. The changes in the 2014 ESO had already been taken into account in the analysis, by reference to regular AEMO updates on generator withdrawals.
The 2019 heatwave stress scenario assumes capacity losses due to outages are similar to actual generation outages during the 2014 heatwave. The effect is shown in Table 8 below relative to the 2019 generation supply.

**Table 8, Assumed supply outages in 2019 scenario**

<table>
<thead>
<tr>
<th>MW</th>
<th>QLD</th>
<th>NSW</th>
<th>VIC</th>
<th>SA</th>
<th>TAS</th>
</tr>
</thead>
<tbody>
<tr>
<td>Percentage</td>
<td>3.9%</td>
<td>0.3%</td>
<td>2.4%</td>
<td>-4.7%</td>
<td>1.0%</td>
</tr>
</tbody>
</table>

---

The 2019 heatwave stress scenario assumes capacity losses due to outages are similar to actual generation outages during the 2014 heatwave. The effect is shown in Table 8 below relative to the 2019 generation supply.
5. 2019 extreme heatwave scenario modelling results

5.1 Introduction

This section sets out the modelling results for an extreme heatwave stress scenario set in February 2019. The scenario extrapolates from the actual extreme heatwave that occurred in January 2014. There is of course a high level of uncertainty over outcomes and a range of potential outcomes were modelled. Of this range, three outcomes are quantified in this section.

The remainder of the section identifies and discusses a range of relevant considerations and issues. Some of these were directly taken into account in scenario modelling. Others were not directly taken into account and should be borne in mind when interpreting modelling results.

5.2 Stress scenario result

Table 9 below shows the overall supply demand balance in a 2019 stress scenario. This indicates a substantial operational deficit in Victoria and a smaller but still significant deficit in South Australia.

Table 9 Supply-demand balance for stressor February 2019 heatwave scenario

<table>
<thead>
<tr>
<th>MW</th>
<th>QLD</th>
<th>NSW</th>
<th>VIC</th>
<th>SA</th>
<th>TAS</th>
</tr>
</thead>
<tbody>
<tr>
<td>Demand</td>
<td>10,127</td>
<td>15,049</td>
<td>11,029</td>
<td>3,391</td>
<td>1,579</td>
</tr>
<tr>
<td>Generation</td>
<td>11,130</td>
<td>15,456</td>
<td>9,819</td>
<td>2,833</td>
<td>2,528</td>
</tr>
<tr>
<td>Net imports</td>
<td>0</td>
<td>-238</td>
<td>322</td>
<td>510</td>
<td>-594</td>
</tr>
<tr>
<td>Balance</td>
<td>1,002</td>
<td>170</td>
<td>-889</td>
<td>-48</td>
<td>356</td>
</tr>
<tr>
<td>Interconnector utilisation</td>
<td>0%</td>
<td>100%</td>
<td>100%</td>
<td>100%</td>
<td></td>
</tr>
</tbody>
</table>
The likely result would be rolling blackouts and the system would be vulnerable to any further adverse movements in the supply-demand balance. Economic costs including significant USE could be incurred. Any USE under the extreme heatwave scenario would be likely to remain within mandated reliability parameter which limits outages to 0.002 per cent per region in a typical year. In addition, any overall shortfall is likely to be significantly less than the indicative 937MW (over Victoria and South Australia) for a range of reasons, as discussed below.

5.3 Alternative stress scenario results

A range of alternative outcomes under a stressor scenario are possible. Outcomes depend on assumed demand, interconnector availability, generator outages and wind output. This highlights that South Australia and Victoria are vulnerable to low reserves and supply shortfalls under a range of possible conditions.

The modelling highlighted that interconnector outages or capacity constraints present significant risks to security and reliability of supply. Outages or capacity constraints are highly possible during the heatwave scenario as a result of thermal operating limits (Basslink) and bushfire risks (Snowy and Heywood).

A further complication is that interconnector transfer capacity is often impaired during periods of peak demand due to network congestion. For example, under peak Snowy output, there is limited capacity to transfer generation reserves and supply from NSW to Victoria. Congestion in North Western Victoria (or Eastern South Australia) during peak demand periods would also limit total transfer capacity between South Australia and Victoria.

In the stressor scenario, it is assumed that offline generation would remain offline. It is, however, likely that some or all of this capacity would be returned to service under the AEMO’s forecast high demand scenario.

It is assumed that in the February 2019 heatwave firm wind at the point of maximum demand would be equivalent to the average wind output during the January 2014 heatwave. A significantly higher quantity of wind output was experienced during part of the January 2014 event and it is possible that a higher quantity of wind could be available at the point of maximum demand. This could also reflect additional wind capacity depending on the outcome of the 2014 MRET review.

Taking all the foregoing points into account, with unchanged demand, an alternative outcome could vary from the stressor outcome in the following key respects:

- Offline generation capacity could be returned to service. This reflects the fact if demand tracked the AEMO’s high scenario, this would be evident well before the summer of 2018/19. As only a small portion of offline capacity is located in Victoria, this makes the least difference to the Victorian balance.

35 As noted throughout this report, the economic cost of USE is modest relative to electricity supply costs during maximum demand.
• Basslink and Heywood capacity could be impaired. This reflects assumed extreme ambient temperatures along with a high probability of bushfire activity along the Heywood interconnector corridor.

• Higher firm wind capacity may be available at the point of maximum demand.

Under these alternative assumptions, there would be no shortfalls, although low reserve conditions would be experienced in Victoria. The modelled alternative outcome is summarised in Table 10 below.

Table 10 Alternative stressor scenario— with higher firm wind, return of offline plant and impaired Basslink and Heywood

<table>
<thead>
<tr>
<th>MW</th>
<th>QLD</th>
<th>NSW</th>
<th>VIC</th>
<th>SA</th>
<th>TAS</th>
</tr>
</thead>
<tbody>
<tr>
<td>Demand</td>
<td>10,127</td>
<td>15,049</td>
<td>11,029</td>
<td>3,391</td>
<td>1,579</td>
</tr>
<tr>
<td>Generation</td>
<td>12,456</td>
<td>16,122</td>
<td>11,118</td>
<td>4,448</td>
<td>2,817</td>
</tr>
<tr>
<td>Net imports</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Balance</td>
<td>2,329</td>
<td>1,073</td>
<td>89</td>
<td>1,057</td>
<td>1,238</td>
</tr>
<tr>
<td>Interconnect or utilisation</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
</tr>
</tbody>
</table>

If demand tracks below the AEMO’s high scenario, the risk of low reserves or supply shortfalls declines. If the AEMO’s medium scenario is applied to the baseline case, there could be a shortfall in Victoria.

Table 11 below shows the relative impact of applying the AEMO’s low demand scenario under the alternative stressor scenario. This suggests that, even with offline capacity remaining offline, and technical constraints on both Heywood and Basslink, there are positive balances in each region.

Reference to the low AEMO demand scenario is not intended to imply that it is considered more or less likely than the high scenario above.
Table 11 Alternative stressor scenario – with AEMO low demand scenario

<table>
<thead>
<tr>
<th>MW</th>
<th>QLD</th>
<th>NSW</th>
<th>VIC</th>
<th>SA</th>
<th>TAS</th>
</tr>
</thead>
<tbody>
<tr>
<td>Demand</td>
<td>8,984</td>
<td>13,614</td>
<td>9,874</td>
<td>3,179</td>
<td>1,103</td>
</tr>
<tr>
<td>Generation</td>
<td>11,181</td>
<td>15,622</td>
<td>11,023</td>
<td>4,030</td>
<td>2,817</td>
</tr>
<tr>
<td>Net imports</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Balance</td>
<td>2,197</td>
<td>2,008</td>
<td>1,149</td>
<td>851</td>
<td>1,714</td>
</tr>
</tbody>
</table>

5.4 Other relevant considerations and issues

The preceding discussion focused on more readily modelled factors. This section discusses other relevant developments and issues that would affect NEM security in a February 2019 extreme heatwave scenario.

5.4.1 Evolving generation mix

Figure 15 below provides the forecast firm generation supply mix. It highlights the significant differences in firm capacity generation type between NEM regions.

Notable features include the high reliance on gas and wind in South Australia, especially following the removal of two coal fired plants from service. Firm wind capacity for South Australia is based on 8.6 per cent of total wind capacity for summer.

A key benefit from increased wind capacity is that it is complementary with hydro-electric output. Hydro-electric output is constrained by water storage. Extended droughts in future could constrain energy output from hydro-electric systems.

If there is excess wind output relative to demand, for example overnight, this output (along with any excess output from thermal generation) can be used for pumped hydro storage. This enables hydro facilities to be available to operate at capacity during maximum demand the following day.
Assumed solar is limited to a large scale solar facility in NSW. Rooftop solar PV is treated as negative demand and is incorporated into the demand forecast.

Wind and solar PV capacity are growing, particularly in South Australia where there is a relatively high penetration of both technologies. High wind output is sufficient to reverse import flows to export flows. Solar PV may defer peak operational demand by up to 2½ hours.

This deferral of peak demand in South Australia, along with the time difference with Victoria, reduces maximum operational demand aggregated over both Victoria and South Australia. This increases system security and reliability in these two regions.

Assumptions about future rooftop solar PV uptake contribute to differences between the three AEMO forecast scenarios. The high demand scenario assumes a lower rooftop solar PV uptake relative to the medium and low demand scenarios.

The risk to security of supply from increased variable generation capacity is considered to be low to moderate. This reflects:

- the slow pace of deployment relative to the NEM’s total size;
- the conservative planning assumptions of firm summer peak capacity (highest in South Australia at just 8.6 per cent); and
- the small size of even large wind farms compared to the largest scheduled generators in each region, the loss of which AEMO must plan for as a contingent event.

A key risk is access to ancillary services, in particular frequency control post islanding of small regions like South Australia and Tasmania. These risks may be addressed by

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Source: AEMO 2013 ESOO with updates to July 2014

adaptation of existing frequency control schemes, as future variable generation capacity is commissioned.

5.4.2 Regional islanding and frequency control

The historical analysis has identified interconnector failures (separation) and frequency islanding of NEM regions among the most significant power system risks from EWEs. This includes both three earlier EWEs resulting in actual (and very significant) power system impact and three later EWEs where the islanding of South Australia including probable load shedding was considered a credible contingent event.

Islanding is significant because the sudden imbalance of supply and demand causes a fast deviation of frequency from NEM technical standards with the potential automatically to trigger under-frequency load shedding and to trip generation, further unbalancing the system.\textsuperscript{38} As noted above, this is of particular concern in smaller and more remote regions. There are already special schemes in place in Tasmania and South Australia. The AEMO is exploring adaptations for emerging conditions in South Australia, taking into account jurisdictional preferences over the conditions for load shedding.

5.4.3 Native and operational demand

Scenario modelling is based on operational demand; that is the demand seen by generators in the NEM including scheduled, semi-scheduled generation and non-scheduled wind generation over 30MW capacity. Native demand is an alternative measure of demand.

Native demand provides a picture of the total energy system, with the addition of all small scale non-scheduled generation, which is not dispatched by the AEMO, to operational demand. Use of AEMO’s native forecasts in scenario modelling both increases supply and reduces demand and hence improves the overall balance relative to operational demand. In the high demand AEMO scenario, native generation is lower than in the other two AEMO scenarios.

5.4.4 Existing generator financing risks

If recent oversupply trends were to continue, it is possible that some highly leveraged generators may breach their financing obligations or face re-financing difficulties. A possible risk not taken into account in the scenario modelling described above is that some existing generation capacity may not be available due to the crystallization of financing risks.

For present purposes, there are two types of generator risks:

- Balance sheet related. Balance sheet related risks arise where adverse business conditions lead to a situation where the owner of a generator is unable to meet its debt covenants. In this case, the ownership entity is no longer viable, but the power station may still be viable, provided that sales revenues from output exceed operating and efficient capital costs (excluding costs from inefficient financing).

\textsuperscript{38} This is not to imply this potential is always realised. There are two separation events in the study period that had no significant impact, including one associated with the Black Saturday Bushfires. However as this occurred at midnight the system impact was insignificant.
• Wholesale price related. Wholesale price related risks would arise when the power station itself is no longer viable because operating and efficient capital costs exceed the value of its output.

This distinction is illustrated by Redbank Energy Pty Ltd, which is the ASX listed company that owns the Redbank Power station in the Hunter Valley. In October 2013 Redbank Energy’s subsidiary Redbank Project Pty Ltd was notified by its secured lenders of the appointment of receivers to Redbank Project. The power station continues to be operated by its receivers under its existing offtake contracts. In other words, the power station appears to be covering at least its operating costs under receivership.

On the other hand, in the case of the fleet of mothballed and retired power stations, output prices were judged by the owners to be insufficient to recover operating and actual capital costs. This highlights that balance sheet related risks are unlikely, on their own, to be a threat to the availability of generation supply and can be set aside for present purposes.

5.4.5 Peaking gas generation risks
The scenario modelling undertaken for this project highlights that gas fired generation capacity will continue to be required in order to meet peak system demand. Peaking gas generators rely on the likelihood of future price spikes to generate revenue in the meantime, via the sale of forward price caps and other financial instruments.

Excess generation capacity (including the possibility offline generation is returned to service), and a weaker demand outlook, are likely to be reducing income from the sale of forward price caps and other hedges. To the extent this is so, then a peaking gas generator may be unable to meet its ongoing financing and operational commitments. On the other hand, if future demand tracks at higher levels, then some mothballed gas generation could be brought back into service.

Gas supply costs are expected to increase substantially as a result of the construction of large scale LNG facilities in Queensland. A possible risk is that gas supplies are difficult to obtain, if available supplies have been pre-committed to export markets.

In addition, if annual output and gas consumption is lower, unit gas supply costs (including transmission) are likely to be more expensive. This could further raise the cost of supplying demand during extreme heatwaves.

The threat to gas generation is in part wholesale price related, along with rising production costs. Unlike the balance sheet issue discussed above, this appears to be a significant threat and should not be set aside.

The problem is illustrated in the decision by the owners of the Pelican Point to withdraw half the capacity from the market at the end of July 2014. The scenario modelling highlights that the supply-demand balance in South Australia is the most sensitive. The withdrawal of part of Pelican Point’s capacity increases energy security risks in South Australia.

5.4.6 Drought

An extreme heat wave event or series of events could more likely occur during a drought when water supplies are low and demand is high. It is possible that hydro and other generation output could be restricted and potential capacity could be curtailed.

Subsequent to the most recent major drought, information on the impact of water availability on generation capacity has been substantially improved – most notably via the AEMO’s quarterly Energy Adequacy Assessment Projection reports. In addition, generators invested in new plant and processes to improve efficiency in water use, including use of recycled wastewater. A notable example is Eraring Energy which made a substantial investment in new cooling water systems in response to thermal pollution limits for Lake Macquarie.

5.4.7 Risks around return of offline generation

In the alternative stressor scenario, it is assumed that offline generation is returned and available. If soft wholesale market conditions continue, it is possible that some offline generation capacity could be withdrawn. This reflects the cost of maintaining offline generation.

In addition, recommissioning offline generation may be costly. For example, it seems likely that, following an extended shutdown, significant expenditure is being applied to ensure Tarong units are available. The high cost of refurbishing the Muja power station in Western Australia is also notable.

On the other hand, maintaining and if necessary recommissioning offline generation capacity is likely to be far more attractive than investing in the development of new generation capacity options. This development can be very costly including consenting, design and other activities in advance of any final commitments. These considerations are especially relevant where there is a high level of uncertainty over both future demand and cost relativities between varying generation technologies and carbon emissions intensities.

5.4.8 Reliability and Emergency Reserve Trader (RERT)

Under the extreme heatwave scenario, it is possible that RERT could be activated to ensure system reliability. The RERT provides a short window (90 minutes) to enable supply and demand to be brought into balance. If the shortfall is for an extended period, RERT as currently configured would not prevent outages.

The closure of the Port Henry smelter suggests that existing RERT capacity in Victoria could be reduced, or that alternative sources of reserve capacity would be required. It is possible that the Wonthaggi desalination in plant in Victoria and the Adelaide desalination plant in South Australia could provide significant RERT services. While smaller in individual capacity, a key advantage of desalination plants in terms of RERT services is they may not be subject to a 90 minute limit.

5.4.9 Demand side participation

A number of proposals are under consideration to improve demand side participation. This includes pricing reform and other incentives intended to temper demand during high price periods. If these proposals were implemented and effective by the time of any 2019 extreme
heatwave, they could moderate demand, thereby increasing security reserves and reducing the risk of supply shortfalls.

5.5 Conclusions from scenario analysis

The outlook for the future security and reliability of the NEM in the summer of 2019 appears to be better than it was in January 2014. This finding is after taking into account both changes in the future generation mix and the increasing future probability and severity of extreme heatwaves.

The scenario modelling undertaken for this project suggests that, even under the AEMO’s high forecast demand scenario and a 1 in 50 year assumed demand threshold, total system demand would be less than five per cent higher than the maximum historical demand in the two most vulnerable markets – South Australia and Victoria.

Under a stressor scenario, there would be rolling blackouts and the system would be vulnerable to any further adverse movements in the supply-demand balance. Such outcomes would be likely to remain within mandated reliability parameter which limits outages to 0.002 per cent in a typical year. In addition, the overall shortfall is likely to be less than indicated above for a range of reasons discussed above.

Under an alternative stressor scenario, low reserves could be experienced in Victoria. This reflects the impact of an assumed constraint on the Basslink interconnector alongside the more limited impact for Victoria of returning currently offline generation to service.

Both the stressor scenario and the alternative stressor scenario apply the AEMO’s high demand forecast, along with the 1 in 50 year event threshold. If these scenarios are applied alongside the AEMO’s low demand scenario, and using the same 1 in 50 year threshold, then there is sufficient supply to meet operational demand.

Moderating demand is partly being offset by generation capacity being withdrawn from service. Nearly 4000MW of capacity has been withdrawn since mid-2012. Any further withdrawals could pose risks to system reliability. A little more than half the withdrawn generation capacity is offline.

If actual demand tracked more closely to the AEMO’s high growth scenario, it could reasonably be expected that most currently offline generation could be brought back into service. This would improve the supply/demand balance but would not remove the risks of short duration outages under a stressor (1 in 50 year event) extreme heatwave, alongside generation and transmission outages.

Under an alternative stressor scenario, the return of offline generation and the possibility of higher wind output suggest that supply may be adequate (just) to avoid any shortfall, even if there are significant constraints on key interconnectors due to extreme ambient temperatures and the risk of bushfires. If the alternative stressor scenario is applied under the AEMO’s low demand scenario, there would be sufficient supply to meet demand, even if offline generation remains offline.

Interconnector related risks would remain significant and could increase in parallel with any increase in the severity or frequency of extreme heatwaves. A key risk relating to interconnectors arises from potential tripping of generation as a result of system instability.
during an islanding process. These risks are well known already and the AEMO is continuing to develop and improve measures for addressing them.

There would be a higher risk that capacity is constrained on Basslink, or lost altogether on other critical interconnectors as a result of heightened bushfire risks. Under a high demand scenario, it is possible that an upgrade to the Basslink interconnector, to remove or reduce existing thermal ratings limits, could be feasible and competitive with other security related investments. Similarly, additional investments relating to Murraylink and Heywood could be undertaken. If these investments occurred, energy security for both Victoria and South Australia would improve.

The scenario modelling results relate to operational demand. When small scale non-scheduled generation capacity is also taken into account, the overall demand supply balance is more favourable. If additional wind capacity is constructed in the lead up to 2020, by early 2019 there could be significant additional firm wind capacity available in both Victoria and South Australia. Various initiatives to increase demand side participation could also be expected to moderate peak demand and thereby improve the overall supply/demand balance.
6. General conclusions

6.1 Historical analysis

The historical analysis of the 54 identified extreme weather events highlights that heatwaves and especially extreme heatwaves are the most important environmental threat to the security of both the NEM physical power system and market.

Heatwaves and bushfires constitute the large majority of the extreme weather events. The threat to NEM security from heatwaves takes various forms. Key physical impacts include low reserves and unserved energy. Other impacts can include damage and loss to electricity infrastructure and higher insurance and other operating and maintenance costs.

The historical analysis found that:

• Almost uniquely amongst extreme weather events, heatwaves can be widespread and able to affect simultaneously up to five of the six NEM regions.
• Heatwaves are associated with high demand, increasingly driven by the widespread penetration of air-conditioning, and in all states except Tasmania associated with annual maximum demand.
• Heatwaves are strongly associated with bushfires and lightning strikes, which pose the most significant environmental threat to the power system at a bulk supply level.
• Heatwaves are associated with a reduction in transmission and generation capacity as equipment operates close to technical limits.
• High demand during extreme heatwaves gives rise to congestion on key interconnectors – this reduces the extent surplus capacity and energy in one region can be shared with another.
• Heatwaves and/or bushfires are already adversely affecting the security of the power system in terms of lost generation and load, and unserved energy.

Environmental caused power system incidents are a minority of all power system incidents identified as having “significant” physical impact on the NEM. Heatwaves and bushfires are associated with three quarters of extreme weather events with significant impacts on the power system. These include three such events where unserved energy (USE) exceeded 1000MWh.

Supply outages result in business losses and disruption to communities and families. If the value of customer reliability (VCR) is $20,000/MWh, then a 30 minute 1000MW outage implies a cost of $10m. On this basis VCR for the three greatest USE events are as follows:

• $46m for the 2009 South East Australia extreme heatwave;
• $34.7m for the 2007 Great Dividing Complex fires and severe heatwave; and
• $30m for the 2001 bushfire triggered islanding event.

This highlights that, even if the value of VCR were doubled, the economic cost of USE is modest relative to aggregate electricity supply costs and in particular the cost of maintaining supply during maximum demand.
Affordability/competitiveness impacts include substantially higher network and wholesale market costs, and therefore consumer bills. The Productivity Commission (PC) has concluded that peak demand (shown in this report to coincide with extreme heatwaves) adds $350 per year to typical power bills.

This $350 per annum value is equivalent to between 22.2 per cent and 36.7 per cent of the per-customer retail cost stack across the NEM. The variability reflects differences in typical annual consumption, network and wholesale costs.

The PC estimate only covers infrastructure costs – network and generation capacity. If fuel costs, which are higher during peak periods, are included, the cost would exceed $350 per year. The PC estimate also excludes the cost of any USE attributable to excess demand.

Both the frequency and severity of extreme heatwaves have increased over the study period. Available power system data appear to indicate a higher number of system events in the second half of the period, relative to the first half. This may reflect better data availability and reporting post 2007 and not represent a real trend.

Over the last three or four years, heatwaves and bushfire events have had little significant impact. This suggests that the direct impact of heatwaves on NEM markets may be decreasing, even while their frequency and severity increases.

The reduced impact may in part be attributable to improvements in the NEM’s operational resilience. These include improvements in system management and security related investments. Lower than expected demand growth, and falling demand in recent years, also appear to be contributing to the reduced impact of extreme heatwaves. For example, there is now significant excess generation capacity in most parts of the NEM.

Advanced weather forecasts, including season ahead climatic forecasts, mean there is generally adequate power system planning time to manage supply and demand. For example, both load and generation were reduced in advance of the landfall of Cyclone Yasi, and Reserve and Emergency Reliability Trader contracts were established (for the first time) months ahead of the January 2014 South-East Australia heatwave.

Cold and wet extreme weather is less significant, as it is generally not associated with high demand. These types of event are generally local or at most regional in extent. They are damaging to distribution and occasionally transmission assets, but not to an extent that the power system cannot be reconfigured to maintain bulk supply. Typically, in cold/wet EWE, bulk supply is re-established before load (distribution).

Genuine shocks to the system come through unpredictable events. Although not weather related, the Latrobe Valley earthquake of 19 June 2012 is included as a power system event of environmental cause and very significant impact, with the distinction of being more difficult to predict than extreme weather events.

### 6.2 Stress testing a 2019 extreme heatwave scenario

Based on the stress testing of a future extreme heatwave scenario, it appears future changes in the generation mix are unlikely to reduce the security of future NEM physical and market operations. Given an increasing frequency and severity of extreme heatwaves, the outlook
for the future security of the NEM in the summer of 2019 appears to be no worse than it was in January 2014.

An extreme heatwave (‘stress testing’) scenario set in February 2019 is modelled to test the impact of a more severe repeat of the January 2014 heatwave for the NEM. As part of the stress testing, it applies the high demand scenario from the AEMO’s 2014 National Energy Forecast Report. All three AEMO demand scenarios incorporate an additional variable to reflect the increasing frequency and severity of extreme heatwaves.

In addition, the scenario assumes the extreme heatwave results in maximum demand exceeding a 1 in 50 year threshold in Victoria simultaneously with a 1 in ten year threshold in South Australia, Tasmania and NSW/ACT. The lower threshold for South Australia reflects the fact that maximum demand in South Australia is likely to occur more than 2 hours later than in Melbourne, partly due to the time difference and partly due to the high penetration of solar PV in South Australia.

It is assumed there is no new thermal generation capacity installed in Victoria or South Australia, the two jurisdictions with the tightest supply-demand balance. The AEMO’s conservative forecasts of firm wind are applied (8.9 per cent of installed capacity in South Australia during summer). Moreover, it is assumed there is no additional wind capacity beyond the existing and committed capacity at the time of the 2013 AEMO Electricity Statement of Opportunities.

Under these conditions, there is a high likelihood that critical interconnectors would be impaired, due to technical operating limits. Accordingly, it is assumed transfer capacity is impaired in some cases, and lost altogether in others. This is especially relevant given the high probability of bushfires occurring under the stress scenario.

On the other hand, under the high demand scenario, it seems likely that some or all of the 2,298MW of offline generation would be returned to service. However, while this would improve conditions, this would have relatively little impact on Victoria, where there is only 95MW of offline generation.

Under the stress testing scenario, a range of outcomes is possible. In some cases, there is a high likelihood of significant and costly outages in South Australia and Victoria. In other cases, however, there are low reserves but possibly no outages. In particular, the modelling highlights that if demand tracks closer to the AEMO’s low scenario, or wind output is higher, it is likely that supply is sufficient to meet maximum demand. Taken as a whole, the modelling indicates that any outages would be within mandated supply parameters.

### 6.3 Energy security under future extreme heatwaves

#### 6.3.1 Reliability

Based on the stress testing of a future extreme heatwave scenario, it appears future changes in the generation mix are unlikely to reduce the security of future NEM physical and market operations. Given an increasing frequency and severity of extreme heatwaves, the outlook
for the future security of the NEM in the summer of 2019 appears to be no worse than it was in January 2014.

Some loss of supply has occurred from time to time and this risk remains in the future. South Australia and Victoria have the greatest risk of bulk supply losses. Taken as a whole, the modelling indicates that any outages would be well within mandated supply parameters. This suggests that the cost of USE would be well below the cost of additional security related power system investment.

For the most part, the likely recent improvement in the reliability dimension of security reflects an improvement in the supply demand balance attributable to forecast demand moderation, especially in the NEM regions most at risk during extreme heatwaves. This moderation is partly attributable to the impact of rooftop solar PV. Its output is treated as negative demand for forecasting purposes.

A further key benefit of rooftop solar PV is that it defers the time of day when maximum demand is experienced in Adelaide. This reduces the risk maximum demand for both Adelaide and Melbourne occurs at exactly the same time during a large scale (multi-State) extreme heatwave event.

Moderating demand is partly being offset by generation capacity being withdrawn from service. Nearly 4000MW of capacity has been withdrawn since mid-2012. Any further generation withdrawals in Victoria and South Australia could pose risks to physical system security.

### 6.3.2 Sustainability

Existing market and planning mechanisms appear sufficient – with reservations identified below – to anticipate and respond to changing circumstances and emerging vulnerabilities. Technical changes are currently in development to manage system stability under expected changes in the future generation mix.

A possible area of concern relates to the future availability of gas fired peaking generation. This reflects the falling value of this capacity, due to the flat and possibly declining outlook for maximum peak demand. This is likely to be placing downward pressure on expected revenues. At the same time, gas supply costs appear to be increasing in anticipation of Queensland liquefaction facilities coming online.

If actual demand tracked more closely to the AEMO’s high growth scenario, it could reasonably be expected that most currently offline generation could be brought back into service. This would improve the supply/demand balance but would not remove the risks of short duration outages under a stressor (1 in 50 year event) extreme heatwave, alongside generation and transmission outages.

RERT provides up to a 90 minute reserve buffer to enable demand and supply to be balanced. The closure of a major aluminium smelter in Victoria poses risk to the RERT. It seems likely that alternative options could be procured to supply a similar service.

A number of proposals are under consideration to improve demand side participation. This includes pricing reform and other incentives to temper demand during high price periods. If these proposals were implemented and effective by the time of any 2019 extreme heatwave,
they could moderate demand, thereby increasing security reserves and reducing the risk of supply shortfalls.

For small customers, electricity prices in the NEM are averaged over time and therefore over different types of customers. This means demand side response during extreme heatwaves is limited to larger electricity consumers, rather than all consumers.

Inefficient retail pricing in the NEM is likely to be undermining the sustainability aspect of energy security. This is because inefficient retail electricity pricing is likely to lead to excess use of and investment in NEM physical capacity to meet peak demand. This is likely to be driven by demand from consumers who are able to ‘free ride’ during peak price periods. At the same time inefficient pricing suppresses demand at other times and by other users and may be contributing to flat or falling NEM wide demand.

**6.3.3 Competitiveness and affordability**

Competitiveness and affordability has substantially declined in recent years due to a 70 per cent increase in typical retail electricity prices reported in the 2012 PC report. While price increases for large industrial and commercial consumers is likely to be less than 70 per cent, they are nevertheless substantial. Extreme heatwaves are a substantial contributor to price rises and have therefore adversely affected the competitiveness and affordability dimension of NEM security.

The cost of meeting demand during extreme heatwaves is likely to comprise more than 22 to 37 per cent to the power supply costs for a typical small consumer, depending on their location in the NEM. Under conditions of falling per capita demand, and regulated network pricing, this percentage could be increasing. Extreme heatwaves are therefore a significant contributor to the decline in the competitiveness and affordability aspects of energy security over the last five years.

**6.4 Possible threat to future energy security**

It is possible that inefficient retail electricity pricing for residential and small business consumers is resulting in inefficient trade-offs between reliability, on the one hand, and competitive, affordable and sustainable electricity supplies, on the other. In other words, there could have been excess power system security investment relative to the risk of future supply shortfalls and outages.

Against this background, more severe and frequent future extreme heatwaves could threaten NEM markets and existing (and future) investments in NEM physical infrastructure.

Substantial retail electricity price rises compared with prices in the broader economy are encouraging consumers to increase energy efficiency and investment in alternative sources of electricity, notably rooftop PV and other forms of distributed generation. As a consequence, both maximum (MW) and annual demand (MWh) are falling in many parts of the NEM.

Falling demand has in turn has contributed to the economic stranding and withdrawal of nearly 4000MW of generation capacity. This is equivalent to more than nine per cent of total NEM generation capacity.
It is possible that a significant portion of network infrastructure is economically stranded. Due to the regulation of network prices, decreases in demand lead to an increase in per unit prices. While consumers do not pay for stranded generation, they continue to pay for any stranded network infrastructure. This increases the attractiveness of alternative options and can reduce demand yet further.

These developments suggest that the future performance of the NEM under the sustainability energy security criterion may be at risk. To the extent this is so, internal and external pressures are not being effectively mitigated, and vulnerabilities are not being identified and managed as well as they could.
Appendix 1 Extreme weather events

Table 12 provides a summary of the master list of 54 extreme weather events considered in this study. It outlines the major characteristics of extreme weather events including event type, duration, extent, peak demand and peak price during the event, any power system impacts, and where applicable, a longer description of the extreme weather-power system event.

As discussed in Section 2, this is a hybrid list of events of interest, arrived at from the perspectives of both meteorological events (from Bureau of Meteorology and Australian Emergency Management data) and power system events (AEMO data). In addition to the intersection of these two sources:

- Some power system reviewable operating incident events which identify environmental causes (bushfire/lightning) are not identified from meteorological data;
- Heatwave events have been included where either the heatwave is extensive (across two or more states) or where heatwaves in single jurisdictions correspond with peaks in demand (even when not extreme or even severe heatwaves); and
- Although not strictly an extreme weather event, the Latrobe Valley earthquake of 19 June 2012 is included as a power system event of environmental causes and very significant impact.

For heatwave-type events, a metric is provided for each jurisdiction in descriptions of heatwave events and bushfires coincident with heatwave conditions. Indicated in parentheses (e.g. 1.5x), this metric is the maximum excess heat factor (EHF) during the event, expressed as a multiple of the local severe heatwave threshold (LSHT), that is, EHF is 1.5 times LSHT.

For each event the impact on the power system is quantified in terms of the maximum demand and wholesale price in the period any lost generation or load, the duration of such outages and, where available or calculable, estimates of unserved energy (USE). Price and demand data are publicly available from AEMO. Lost load, generation and USE have been identified, where possible, from Reviewable Operating Incident reports and Daily Reports provided by AEMO for this study.
### Table 12 Master list of extreme weather events

<table>
<thead>
<tr>
<th>Description</th>
<th>Date</th>
<th>State(s)</th>
<th>Peak as % annual max demand</th>
<th>Peak price</th>
<th>Power System Impact</th>
</tr>
</thead>
<tbody>
<tr>
<td>Heatwaves Hobart (1.7x), Melbourne (1.3x)</td>
<td>2 Feb 1999 to 5 Feb 1999</td>
<td>Victoria, Tasmania</td>
<td>98.9% in Victoria</td>
<td>$3,653 in Victoria</td>
<td>NA</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>NA in Tasmania</td>
<td>NA in Tasmania</td>
<td>NA</td>
</tr>
<tr>
<td>Heatwaves Brisbane (5.92x)</td>
<td>19 Jan 2000 to 23 Jan 2000</td>
<td>Queensland</td>
<td>99.9%</td>
<td>$5,000 (cap)</td>
<td>NA</td>
</tr>
<tr>
<td>Heatwaves Melbourne (1.7x), Adelaide (1.3x)</td>
<td>2 Feb 2000 to 5 Feb 2000</td>
<td>Victoria, SA</td>
<td>100% in SA</td>
<td>$5,000 (cap) in SA</td>
<td>NA</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>96.6% in Victoria</td>
<td>$110 in Victoria</td>
<td>NA</td>
</tr>
<tr>
<td>Severe Storm in Sydney and Region, Victorian bushfires</td>
<td>15 Jan 2001</td>
<td>NSW, Victoria</td>
<td>98.7% in NSW</td>
<td>$5,000 (cap) in NSW</td>
<td>Lost load: 820MW, Duration: 1 hour, 50 minutes</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>76.5% in Victoria</td>
<td>$556 in Victoria</td>
<td>USE: ~1500MWh</td>
</tr>
<tr>
<td>Hot weather in excess of 46C in Sydney. When a grass fire tripped a</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Canberra-Tumut transmission line, inappropriate protection actions led to</td>
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<tr>
<td>the separation and islanding of NSW from Victoria and South Australia,</td>
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<tr>
<td>frequency control tripping load in NSW and generation in Victoria.</td>
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<tr>
<td>Heatwaves Sydney (2.0x), Canberra (3.1x), Adelaide (1.4x)</td>
<td>21 Jan 2001 to 27 Jan 2001</td>
<td>NSW, ACT, SA</td>
<td>100% in NSW/ACT</td>
<td>$3,982 in NSW/ACT</td>
<td>NA</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>96.3% in SA</td>
<td>$4,390 in SA</td>
<td>NA</td>
</tr>
<tr>
<td>Heatwaves Adelaide (1.1x), Melbourne (1.1x)</td>
<td>18 Feb 2001 to 21 Feb 2001</td>
<td>Victoria, SA</td>
<td>91.0% in SA</td>
<td>$3,938 in SA</td>
<td>NA</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>95.7% in Victoria</td>
<td>$3,681 in Victoria</td>
<td>NA</td>
</tr>
<tr>
<td>Description</td>
<td>Date</td>
<td>State(s)</td>
<td>Peak as % annual max demand</td>
<td>Peak price</td>
<td>Power System Impact</td>
</tr>
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</tr>
<tr>
<td>Bushfire - Black Christmas (0.83x NSW)</td>
<td>24 Dec 2001 to 11 Jan 2002</td>
<td>NSW, ACT</td>
<td>84.2% in NSW/ACT</td>
<td>$101 in NSW/ACT</td>
<td>NA</td>
</tr>
<tr>
<td>Heatwaves Brisbane (1.6x) coincident bushfires in NSW</td>
<td>3 Dec 2002 to 5 Dec 2002</td>
<td>Queensland, NSW</td>
<td>99.9% in Queensland 87.48% in NSW</td>
<td>$8,136 in Queensland $2,624 in NSW</td>
<td>Lost generation: 120MW, Lost load 970MW</td>
</tr>
<tr>
<td>Bushfire – Canberra (1.3x)</td>
<td>18 Jan 2003 to 19 Jan 2003</td>
<td>ACT</td>
<td>84.5%</td>
<td>$3,435</td>
<td>NA</td>
</tr>
<tr>
<td>Bushfire - North-Eastern Victoria, Alpine Region</td>
<td>8 Jan 2003 to 19 Mar 2003</td>
<td>Victoria</td>
<td>100.0%</td>
<td>$4,166</td>
<td>NA</td>
</tr>
</tbody>
</table>

Weather conditions were extremely dry and hot with moderate to strong winds and 39 bushfires across NSW. There were 61 EHV transmission trips in NSW triggering lost load and generation.

On 18 January, multiple bushfires in Kosciuszko and Namadgi National Parks surrounding Canberra combined to create a 25 km fire front and wind gusts of up to 65 km per hour which propelled the fire towards Canberra. Four people were killed, 488 houses destroyed and many more were damaged, almost 70 per cent of the ACT’s pasture, forests and nature parks burnt.
<table>
<thead>
<tr>
<th>Description</th>
<th>Date</th>
<th>State(s)</th>
<th>Peak as % annual max demand</th>
<th>Peak price</th>
<th>Power System Impact</th>
</tr>
</thead>
<tbody>
<tr>
<td>Lightning ignited 87 fires in the North-East and East Gippsland regions. Eight of these fires were unable to be contained; they joined together to form the largest fire in Victoria since the Black Friday fires in 1939. More than 40 fires were also started in NSW and ACT. The fires burnt 1.19 million hectares in Victoria and 800,000 hectares in NSW and ACT.</td>
<td>24 Aug 2003</td>
<td>ACT, Victoria, Tasmania</td>
<td>76.9% in ACT 71.7% in Victoria NA in Tasmania</td>
<td>$44.88 in ACT $44.49 in Victoria NA in Tasmania</td>
<td>NA</td>
</tr>
<tr>
<td>Severe Storm - South Eastern Australia</td>
<td>24 Jan 2004 to 31 Jan 2004</td>
<td>Queensland</td>
<td>97.5%</td>
<td>$48.97</td>
<td>NA</td>
</tr>
<tr>
<td>Heatwaves Brisbane (6.1x), Canberra (2.2x), Adelaide (2.1x)</td>
<td>11 Feb 2004 to 24 Feb 2004</td>
<td>Queensland, ACT, SA</td>
<td>100% in Queensland 97.5% in ACT 99.0% in SA</td>
<td>$2,268 in Queensland $1,188 in ACT $4,750 in SA</td>
<td>NA</td>
</tr>
<tr>
<td>Severe Storm - South-East Queensland, Northern New South Wales, Northern Western Australia. Northern Territory</td>
<td>3 Mar 2004 to 31 Mar 2004</td>
<td>NSW, Queensland</td>
<td>97.9% in NSW 95.4% in Queensland</td>
<td>$9,702 in NSW $8280 in Queensland</td>
<td>NA</td>
</tr>
<tr>
<td>Bushfire - Eyre Peninsula (0.53x)</td>
<td>10 Jan 2005 to 12 Jan 2005</td>
<td>SA</td>
<td>100%</td>
<td>$149.10</td>
<td>NA</td>
</tr>
<tr>
<td>Description</td>
<td>Date</td>
<td>State(s)</td>
<td>Peak as % annual max demand</td>
<td>Peak price</td>
<td>Power System Impact</td>
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</tr>
<tr>
<td>Heatwaves Canberra (1.2x), Adelaide (3.2x), Melbourne (2.8x), Hobart (1.4x)</td>
<td>19 Jan 2006 to 23 Jan 2006</td>
<td>ACT, Victoria, SA, Tasmania</td>
<td>96.1% in ACT 98.5% in Victoria 100% in SA 71.5% in Tasmania</td>
<td>$530 in ACT $2995 in Victoria $4900 in SA $72 in Tasmania</td>
<td>NA</td>
</tr>
<tr>
<td>Heatwaves Canberra (1.5x)</td>
<td>26 Jan 2006 to 3 Feb 2006</td>
<td>ACT</td>
<td>100%</td>
<td>$9,739</td>
<td>NA</td>
</tr>
<tr>
<td>Cyclone Larry</td>
<td>20 Mar 2006</td>
<td>Queensland</td>
<td>84.1%</td>
<td>$22.85</td>
<td>Lost generation: 34MW</td>
</tr>
<tr>
<td>Bushfire - Great Divide Complex (1.6x)</td>
<td>1 Dec 2006 to 7 Feb 2007</td>
<td>Victoria</td>
<td>100%</td>
<td>$10,000 (cap)</td>
<td>Lost load: ~2600MW Duration: 40 minutes USE: 1733MWh</td>
</tr>
</tbody>
</table>

Multiple fires combined to form the 'Great Divide Complex' fires in eastern Victoria, burning ~1.3 million hectares over more than 69 days. On 16 January, multiple transmission line trips, separation between Victoria and Snowy and subsequently Victoria and SA.

<p>| Heatwaves Hobart (3.5x), Adelaide (2.5x), Melbourne 1.9x) | 15 Feb 2007 to 19 Feb 2007 | Victoria, SA, Tasmania | 99.2% in Victoria 100% in SA 73.5% in Tasmania | $823 in Victoria $828 in SA $1,463 in Tasmania | Lost load: 181MW (lightning) |</p>
<table>
<thead>
<tr>
<th>Description</th>
<th>Date</th>
<th>State(s)</th>
<th>Peak as % annual max demand</th>
<th>Peak price</th>
<th>Power System Impact</th>
</tr>
</thead>
<tbody>
<tr>
<td>Flood - Gippsland June 2007</td>
<td>27 Jun 2007 to 2 Jul 2007</td>
<td>Victoria</td>
<td>88.1%</td>
<td>$3,745</td>
<td>NA</td>
</tr>
<tr>
<td>Heatwaves Adelaide (2.3x)</td>
<td>29 Dec 2007 to 2 Jan 2008</td>
<td>SA</td>
<td>90.4%</td>
<td>$5057</td>
<td>Nil</td>
</tr>
<tr>
<td>Flood - Queensland Jan 2008</td>
<td>1 Jan 2008 to 31 Jan 2008</td>
<td>Queensland</td>
<td>98.7%</td>
<td>$9,921</td>
<td>Lost generation: 30MW Lost load: 11MW</td>
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<tr>
<td></td>
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<td></td>
<td></td>
<td></td>
<td>Lightning tripped transmission and generation</td>
</tr>
<tr>
<td>Heatwaves Adelaide (1.5x)</td>
<td>7 Mar 2008 to 17 Mar 2008</td>
<td>SA</td>
<td>100%</td>
<td>$9,999.72</td>
<td>Nil</td>
</tr>
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<td></td>
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<td></td>
<td>Actual Lack of Reserve; SA-Vic interconnector restricted; SA separation and load shedding a credible contingent event</td>
</tr>
<tr>
<td>Heatwaves Melbourne (1.2x)</td>
<td>16 Mar 2008 to 18 Mar 2008</td>
<td>Victoria</td>
<td>100%</td>
<td>$7,910</td>
<td>Nil</td>
</tr>
<tr>
<td>Southern States Windstorms</td>
<td>2 Apr 2008</td>
<td>Victoria, SA, Tasmania</td>
<td>67.0% in Victoria 48.3% in SA 74.7% in Tasmania</td>
<td>$69 in Victoria $45 in SA $92 in Tasmania</td>
<td>Nil</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Multiple reclassifications and transmission outages due to lightning</td>
</tr>
</tbody>
</table>

Extreme weather and the National Electricity Market  Page 53
## Extreme weather and the National Electricity Market

<table>
<thead>
<tr>
<th>Description</th>
<th>Date</th>
<th>State(s)</th>
<th>Peak as % annual max demand</th>
<th>Peak price</th>
<th>Power System Impact</th>
</tr>
</thead>
<tbody>
<tr>
<td>Severe Storm - South-East Queensland</td>
<td>16 Nov 2008 to 22 Nov 2008</td>
<td>Queensland</td>
<td>89.8%</td>
<td>$5,061</td>
<td>Nil</td>
</tr>
<tr>
<td>SE Australia heatwave (NSW 1.8x, ACT 1.5x, Victoria 4.7x, SA 5.0x, Tasmania 1.1x)</td>
<td>26 Jan 2009 to 8 Feb 2009</td>
<td>NSW, ACT, Victoria, SA, Tasmania</td>
<td>91.8% in NSW/ACT, 100% in Victoria, 100% in SA, 76.5% in Tasmania</td>
<td>$2,658 in NSW/ACT, $10,000 (cap) in Victoria, $9,999.92 in SA, $6880 in Tasmania</td>
<td>Lost load: total 850MW, Duration: 1½ to 4 hours, USE: 2301MWh</td>
</tr>
<tr>
<td>Bushfire - Black Saturday</td>
<td>7 Feb 2009 to 8 Feb 2009</td>
<td>Victoria</td>
<td>86.3%</td>
<td>$1,951</td>
<td>Lost generation: 142MW, Lost load: total 327MW, Duration: 0 to 4 hours, USE: 252MWh</td>
</tr>
</tbody>
</table>

Multiple reclassifications and transmission outages due to lightning; QNI constrained

The weather across south-east Australia on 29 and 30 January closer to a 1 in 100 year event. Transmission line failures reduced availability of capacity from Snowy and Hazelwood (29th) and Jeeralang (30th), and Basslink ramped off both days. Combined with lower generation availability from MTPASA (in August 2008) to the actual day, leading to actual LOR2 and LOR 3 conditions

Extremely high temperatures to 48.8 (7th), low humidity, strong winds and lightning caused one of Victoria’s worst bushfire events. Two transmission lines tripped together with the trip of several lines the day before due to bushfires leading to system separation and load shedding.
<table>
<thead>
<tr>
<th>Description</th>
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<th>State(s)</th>
<th>Peak as % annual max demand</th>
<th>Peak price</th>
<th>Power System Impact</th>
</tr>
</thead>
<tbody>
<tr>
<td>Heatwaves Canberra (3.28x)</td>
<td>4 Feb 2009 to 9 Feb 2009</td>
<td></td>
<td>98.8%</td>
<td>$3006</td>
<td>Nil</td>
</tr>
<tr>
<td>NSW Severe wind event</td>
<td>24 Aug 2009</td>
<td>NSW</td>
<td>76.0%</td>
<td>$131</td>
<td>Nil</td>
</tr>
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</tr>
<tr>
<td>Heatwaves Adelaide (2.1x), Hobart (1.3x), Canberra (2.5x)</td>
<td>8 Jan 2010 to 14 Jan 2010</td>
<td>ACT, SA, Tasmania</td>
<td>96.5% in ACT 99.99% in SA 74.6% in Tasmania</td>
<td>$1,332 in ACT $9,999.71 in SA $100 in Tasmania</td>
<td>Nil</td>
</tr>
<tr>
<td>Heatwaves Sydney (2.5x), Canberra (1.5x)</td>
<td>21 Jan 2010 to 23 Jan 2010</td>
<td>NSW, ACT</td>
<td>100% in NSW/ACT</td>
<td>$4514 in NSW/ACT</td>
<td>Nil</td>
</tr>
</tbody>
</table>

Very strong winds were passing through the substation at the time caused the conductors to come in close proximity to a steel structure. As a result, the busbar protection was initiated.

Multiple transmission lines and generator tripped during thunderstorm.

Multiple lines tripped due to bush fires, causing interruption to load. Loads were also interrupted due to their own internal protection.
<table>
<thead>
<tr>
<th>Description</th>
<th>Date</th>
<th>State(s)</th>
<th>Peak as % annual max demand</th>
<th>Peak price</th>
<th>Power System Impact</th>
</tr>
</thead>
<tbody>
<tr>
<td>Heatwaves Adelaide (1.5x)</td>
<td>8 Feb 2010 to 10 Feb 2010</td>
<td>SA</td>
<td>100%</td>
<td>$9999.92</td>
<td>Nil</td>
</tr>
<tr>
<td>Extensive flooding -75% of Queensland</td>
<td>30 Nov 2010 to 17 Jan 2011</td>
<td>Queensland</td>
<td>90.0%</td>
<td>$2,561</td>
<td>Nil</td>
</tr>
<tr>
<td>Heatwaves Adelaide (2.1x)</td>
<td>29 Jan 2011 to 2 Feb 2011</td>
<td>SA</td>
<td>100%</td>
<td>$12,199</td>
<td>Nil</td>
</tr>
<tr>
<td>Cyclone Yasi</td>
<td>2 Feb 2011 to 3 Feb 2011</td>
<td>Queensland</td>
<td>90.1%</td>
<td>$9043</td>
<td>Lost load: &lt;50MW</td>
</tr>
<tr>
<td>Cyclone Yasi crossed the Nth Queensland coast around midnight. Twelve 132 kV transmission lines tripped out of service resulting in the disconnection of the four 132kV substations from the power system. Four power stations and two substations were shut down in advance - no resulting reserve deficits. Load was substantially reduced prior to Yasi crossing the coast.</td>
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</tr>
<tr>
<td>Heatwaves Sydney (3.5x), Adelaide (2.2x), Canberra (1.7x)</td>
<td>29 Jan 2011 to 5 Feb 2011</td>
<td>NSW, ACT, SA</td>
<td>100% in NSW/ACT 100% in SA</td>
<td>$12,136 in NSW/ACT $12,199 in SA</td>
<td>Nil</td>
</tr>
<tr>
<td>Actual Lack of Reserve in SA, NSW and Victoria</td>
<td></td>
<td></td>
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</tr>
<tr>
<td>NSW Storm</td>
<td>13 Mar 2011</td>
<td>NSW</td>
<td>68.3%</td>
<td>$33</td>
<td>Nil</td>
</tr>
<tr>
<td>Description</td>
<td>Date</td>
<td>State(s)</td>
<td>Peak as % annual max demand</td>
<td>Peak price</td>
<td>Power System Impact</td>
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</tr>
<tr>
<td>Busbar tripped due to vegetation in heavy rain causing fault</td>
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</tbody>
</table>
| NSW Wind                         | 5 Jul 2011          | NSW      | 89.8%                      | $67        | Lost load: 18MW  
Duration: 22 minutes  
USE: 6.6MWh                                                                                     |
<p>|                                 |                     |          |                            |            | High winds blew lines onto tower frame resulting in an earth fault, tripping first line, which cascaded to through protection control to second line. |
| Heatwaves Brisbane (2.1x)       | 9 Jan 2012 to 11 Jan 2012 | Queensland | 100%                      | $2893      | NA                                                                                     |
|                                 |                     |          |                            |            |                                                                                     |
| Flood - Gippsland                | 4 Jun 2012 to 22 Jun 2012 | Victoria  | 86.2%                      | $125       | Lost generation 1400MW                                                                 |
|                                 |                     |          |                            |            |                                                                                     |
|                                  |                     |          |                            |            | Commencing 4 June 2012, up to 200 mm of rain fell in eastern Victoria, breaking daily rainfall records for June at 23 locations across the state, mainly Gippsland. Many Gippsland locations received a month's rainfall in one day, flooding low-lying areas. The Yallourn coal mine flooded when the Morwell River burst its banks on early June impacting on coal conveyers and therefore the operation of electricity generators. The operator TRUenergy announced it should be able to restore three of the plant's four generators by the end of June. |</p>
<table>
<thead>
<tr>
<th>Description</th>
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<th>Power System Impact</th>
</tr>
</thead>
<tbody>
<tr>
<td>Earthquake, Latrobe Valley</td>
<td>19 Jun 2012</td>
<td>Victoria</td>
<td>85.0%</td>
<td>$56</td>
<td>Lost generation: ~1955MW</td>
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<td></td>
<td>Lost load: 200MW industrial, 200MW UFLS</td>
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<td>Duration: ~25 minutes</td>
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<td>USE: 80MWh</td>
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<td></td>
<td></td>
<td>The strongest earthquake in Victoria for three decades</td>
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<td>struck Gippsland near Moe at a shallow depth of 9.9 km.</td>
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<tr>
<td>Angry summer heatwave (NSW 0.94x, ACT 1.8x,</td>
<td>2 Jan 2013 to</td>
<td>NSW, ACT,</td>
<td>94.1% in NSW/ACT</td>
<td>$103</td>
<td>Nil</td>
</tr>
<tr>
<td>Victoria 0.42x, SA 0.99x, Tasmania 2.8x) and</td>
<td>8 Jan 2013</td>
<td>Victoria, SA,</td>
<td>95.3% in Victoria</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Tasmanian bushfires</td>
<td></td>
<td>Tasmania</td>
<td>94.0% in SA</td>
<td>$4,282</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>75.1% in Tasmania</td>
<td>$4,203</td>
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<td></td>
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<td></td>
<td></td>
<td>$2,188</td>
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<td></td>
<td>Multiply reclassifications due to bushfires/lightning;</td>
</tr>
<tr>
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<td>Vic-SA interconnector reclassified; SA separation</td>
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<td>including probable load shedding a credible contingent</td>
</tr>
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<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>event</td>
</tr>
<tr>
<td>Bushfire – Coonabarabran (1.1x)</td>
<td>7 Jan 2013 to</td>
<td>NSW</td>
<td>100%</td>
<td>$150</td>
<td>Lost generation: 126MW</td>
</tr>
<tr>
<td></td>
<td>20 Jan 2013</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Coincident with Cyclone Oswald</td>
<td>21 Jan 2013 to</td>
<td>Queensland,</td>
<td>92.0% in Queensland</td>
<td>$6,298</td>
<td>Nil</td>
</tr>
<tr>
<td></td>
<td>29 Jan 2013</td>
<td>NSW</td>
<td>84.5% in NSW</td>
<td>$79</td>
<td></td>
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<td></td>
<td></td>
<td>On 25 Jan a bushfire in southern NSW resulted in</td>
</tr>
<tr>
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<td></td>
<td></td>
<td></td>
<td></td>
<td>379MW lost generation.</td>
</tr>
</tbody>
</table>

On 25 Jan a bushfire in southern NSW resulted in 379MW lost generation.
<table>
<thead>
<tr>
<th>Description</th>
<th>Date</th>
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<th>Peak as % annual max demand</th>
<th>Peak price</th>
<th>Power System Impact</th>
</tr>
</thead>
<tbody>
<tr>
<td>Heatwaves Adelaide (1.8x)</td>
<td>15 Feb 2013 to 18 Feb 2013</td>
<td>SA</td>
<td>94.8%</td>
<td>$2,127</td>
<td>Lost generation: 56MW&lt;br&gt;Lost lad: 14MW&lt;br&gt;Duration 3 hrs 14 mins&lt;br&gt;USE: 44MWh</td>
</tr>
<tr>
<td>Bushfire tripped transmission lines</td>
<td></td>
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</tr>
<tr>
<td>Heatwaves Melbourne (0.85x)</td>
<td>7 Mar 2013 to 12 Mar 2013</td>
<td>Victoria</td>
<td>100%</td>
<td>$2,139</td>
<td>Nil</td>
</tr>
<tr>
<td>Actual LOR in SA due to planned outage of Vic-SA interconnector, making SA separation a credible contingent event.</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sydney bushfires, Greater Blue Mountains, Hunter and Central coast, Southern Highlands</td>
<td>13 Oct 2013 to 24 Oct 2013</td>
<td>NSW</td>
<td>84.65</td>
<td>$68</td>
<td>Lost generation: 13MW&lt;br&gt;Lost load: 44MW&lt;br&gt;Duration: 1hr 27mins&lt;br&gt;USE: 75MW</td>
</tr>
<tr>
<td>Strong winds and high temperatures caused 100 (six major) bushfires across eastern NSW, the most serious in the Blue Mountains. Numerous reclassifications and some outages due to bushfires.</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Heatwaves Adelaide (2.3x), Canberra (1.8x), Sydney</td>
<td>17 Dec 2013 to 23 Dec 2013</td>
<td>NSW, ACT</td>
<td>100% in NSW/ACT 99.5% in SA</td>
<td>$7,696 in NSW/ACT $4,377 in SA</td>
<td>Nil</td>
</tr>
<tr>
<td>Description</td>
<td>Date</td>
<td>State(s)</td>
<td>Peak as % annual max demand</td>
<td>Peak price</td>
<td>Power System Impact</td>
</tr>
<tr>
<td>----------------------------------------------------------------------------</td>
<td>---------------------------</td>
<td>------------</td>
<td>-----------------------------</td>
<td>------------</td>
<td>---------------------</td>
</tr>
<tr>
<td>(1.5x) Multiple reclassifications due to lightning</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>NA</td>
</tr>
<tr>
<td>Heatwaves Brisbane (2.7x)</td>
<td>2 Jan 2014 to 6 Jan 2014</td>
<td>Queensland</td>
<td>99.5%</td>
<td>$4377</td>
<td>NA</td>
</tr>
<tr>
<td>Heatwaves Melbourne (6.0x), Adelaide (3.6x), Canberra (1.5x)</td>
<td>12 Jan 2014 to 18 Jan 2014</td>
<td>ACT, Victoria, SA</td>
<td>99.4% in NSW/ACT 100% in Victoria 100% in SA</td>
<td>$310 in NSW/ACT $5,972 in Victoria $6,213 in SA</td>
<td>Nil</td>
</tr>
</tbody>
</table>

Multiple transmission outages and reclassifications due to bushfires/lightning. Basslink tripped from 570MW due to over-temperature at Loy Yang. Actual LOR1&2 in Victoria. RERT contracts 650MW activated but LOR3 did not eventuate.
Appendix 2 Supplementary material

The purpose of this appendix is to provide further information and data on both the historical analysis and future scenario modelling.

Historical analysis

Key extreme heatwaves
The analysis of historical extreme weather-power system events establishes extreme heatwaves and bushfires as the main environmental threat to the security of the NEM power system, particularly in south-eastern Australia. This section briefly considers and contrasts two prominent recent extreme heatwaves: the 2009 SE Australia heatwave, and the extreme heatwave of January 2014.

2009 South East Australia extreme heatwave
The weather across south-east Australia on 28-30 January 2009 was regarded a one in one hundred year event, with severe heatwaves in NSW, ACT and Tasmania and extreme heatwave conditions in Victoria and South Australia. The heatwave was a precursor to the Black Saturday bushfires of 8-9 February. Figure 16 and Figure 17 illustrate daily demand tracking temperature in the week leading up to South Australian annual maximum demand on 28 January and Victorian historic maximum demand was reached on 29 January.

Figure 16 South Australian maximum demand in 2009

![Graph showing daily temperature, demand, and maximum demand as percentage of annual maximum demand in 2009.]
Multiple power system events occurred, including actual lack of reserve (LOR) conditions for 29 and 30 January 2009 and multiple transmission line trips due to lighting and bushfires. The actual LOR3 conditions led to load shedding in Victoria and South Australia on both days.

Forecast reserves were significantly higher than the actual reserves achieved on the day in all forecast timeframes (medium and short term and pre-dispatch). The largest differences were in Victoria, with the main contributors being the actual availability of generation and Basslink being less than forecast on both days. Low forecast demands were also a factor in some cases.

On both days wind farm output was significantly higher than the 8 per cent capacity at time of maximum demand assumed in medium term forecasts. At the time of peak demand on 29 and 30 January respectively, South Australian wind output was 40 per cent and 13 per cent, while Victorian wind output was 19.6 per cent and 8.4 per cent. These differences were not a significant factor in the forecasting differences.

**January 2014 heatwave**

In January 2014 an extreme heatwave in Victoria and South Australia provoked comparisons with similar recent events, especially the 2009 south-east Australia extreme heatwave. This includes a special AEMO report on the performance of the power system compared with the 2009 event.40

Meteorologically, this event was significant for record-breaking extreme heatwaves in South Australia and Victoria, especially as the first ever five-day (South Australia) and four-day (Victoria) periods well in excess of 40°C. Unlike 2009, severe weather conditions were not more widespread. This event was significant for the power system because there were some losses of generation and transmission, significant restrictions on Basslink, and the level of demand had not been seen since the last heatwave in 2009 where record operational demands were set, demand was supplied at all times. Figure 18 and Figure 19 illustrate daily demand and temperatures for the week before annual maximum demand.

---

There were forecast and actual periods of low reserve, particularly in the earlier period of the heatwave before the Loy Yang generator was returned to service, but there was no lack of reserve. In August 2014, AEMO established RERT contracts for the first time, based on MTPASA forecasts. While loss of Basslink during periods of low reserve would have caused the RERT contracts to be applied, this did not occur.

Wind and solar output are growing components of generation capacity, particularly in South Australia where there is higher penetration of both technologies. Their contribution during peak operational demand were significant, if variable over an event of four/five days duration. In particular, high wind in South Australian generation displaced interconnector imports to zero on 17 January, while solar contributed significantly at the time of total demand, and delayed peak operational demand (that seen by power system generators) to a time when system demand is declining, by up to 2½ hours on 16 January.

Implications of the evolution of generation mix
The power system is in the midst of significant change with the emergence and deployment of renewable fuel generation technologies and retirement of fossil fuel generators. In particular wind and rooftop solar photovoltaic (solar PV) generation are beginning to establish sufficient footprint in the NEM that in recent years AEMO’s planning processes have moved:
to include forecasts and reports of solar PV contribution to total demand (over and above operational demand as seen by NEM generators);\textsuperscript{41} and

undertake a range of wind integration studies to understand the technical and operational issues for maintaining power system reliability and security as an increasing proportion of operational demand is met by variable generation.\textsuperscript{42}

A key point of this evolution is that despite, for example, the rapid emergence of ‘prosumers’ in response to escalating retail electricity prices, from the point of view of the 200,000 GWh per annum NEM power system, these new generation sources are coming online at a slow to steady pace that allows the system operator to understand and adapt to the system impact. This allows steady, rather than radical responses, by AEMO to these challenges.

Technologies affect the power system in varying ways. Embedded generation is seen by the power system as negative demand and is probably more a distribution level issue. Wind and utility-scale solar generation are significant in the NEM with varying degrees of penetration across the states.


Table 13). Wind is most significant in South Australia with a third of nameplate capacity, followed by Tasmania and Victoria.

In terms of security of supply, Table 13 indicates part of AEMO’s response to the variability of wind generation in longer term planning: forecast projections in the National Electricity Forecasting Report have conservative estimates of ‘firm’ wind capacity available during summer peaks, varying from 2 to 8 per cent of nameplate capacity. As observed in the 2009 and 2014 heatwaves, actual wind generation at the time of peak demand is often many times this capacity. This lower estimate means that possible shortfalls are identified and responses are developed well in advance.

In terms of the current security of supply, AEMO observes that the nature of wind generation infrastructure and operation mean that even in cases of substantial errors in forecast wind generation or, as is more likely, loss of wind farm generation through transmission failures, the total loss to the system is generally smaller than the loss of the largest scheduled coal or gas plant, for which AEMO must plan as a contingent event. Furthermore, for some time wind generation has been registered as semi-scheduled generation (over 70 per cent in South Australia) with a degree of central control.
Table 13 2014 NEFR wind generation capacity for 2014/15 (MW)

<table>
<thead>
<tr>
<th></th>
<th>Queensland</th>
<th>NSW</th>
<th>Victoria</th>
<th>SA</th>
<th>Tasmania</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nameplate capacity</td>
<td>12</td>
<td>666</td>
<td>945</td>
<td>1,362</td>
<td>373</td>
</tr>
<tr>
<td>Total capacity</td>
<td>11,067</td>
<td>15,909</td>
<td>11,434</td>
<td>3,993</td>
<td>2,622</td>
</tr>
<tr>
<td>Nameplate capacity %</td>
<td>0.1%</td>
<td>4.2%</td>
<td>8.3%</td>
<td>34.1%</td>
<td>14.2%</td>
</tr>
<tr>
<td>Firm summer peak capacity</td>
<td>0</td>
<td>36</td>
<td>33</td>
<td>84</td>
<td>7</td>
</tr>
<tr>
<td>Firm summer peak capacity %</td>
<td>0.0%</td>
<td>0.2%</td>
<td>0.3%</td>
<td>2.1%</td>
<td>0.3%</td>
</tr>
</tbody>
</table>

1. NSW includes 113MW Broken Hill Solar Plant.

AEMO identifies greater risks to reliability in terms of ancillary services such as frequency control, especially in South Australia in the event of separation from the NEM when all frequency control services must be obtained within the state. Even then the threat is both only gradually emerging, as noted above, and may be addressed by adapting existing schemes to suit. First, it is technically feasible for variable generation to provide ancillary services, but there is currently no incentive for them to do so in favour of the supply of load. Also the NEM already has a number of special schemes in place in Tasmania that could be adapted to South Australia. These schemes exist because Tasmania shares significant characteristics with the emerging state of South Australia’s power system – it is a small market, easily isolated from the NEM whereupon dependent on its own resources to maintain reliability and security.

In summary, AEMO’s view is that the evolution of the generation mix, and particularly variable generation, does not present any challenges that it does not already or cannot in a timely fashion address.

**Water-energy nexus**

An area of interest is the nexus between water and energy with regards to high risk scenarios. An extreme heat wave event or series of events could more likely occur during a drought when water supplies are low and demand is high. There are two possible issues relating to:

- Water use in electricity production
- Electricity use for water supply

**Water use in electricity generation**

During 2007/08, generation capacity was substantially curtailed due to water shortages in south-east Queensland and elsewhere. This led to water restrictions for the use of fresh water cooling water at Tarong North and Swanbank power stations. At the same time, storage in the Snowy hydro-electric system fell to historic lows and substantially curtailed
output. As a consequence, generation capacity across the NEM was materially reduced for an extended period. Output from Victoria’s Latrobe valley generators was also affected.

Independently from the drought, output from other generation is also reduced during warmer summer periods due to limits on thermal pollution of cooling water reservoirs. This most notably affects the NSW Central Coast power stations of Vales Point, Eraring and Munmorah.

The water shortage led to substantial increases in the volume of forward hedge contracts traded and a substantial increase in the volume of hedges traded through the ASX instead of bilaterally. The drought resulted in substantial energy trading losses for major retailers and the financial failure of one smaller retailer. This is the only occasion retailer of last resort mechanisms have been applied.

Subsequent to this drought, information on the impact of water availability on generation capacity has been substantially improved – most notably via the AEMO’s quarterly Energy Adequacy Assessment reports. In addition, generators invested in new plant and processes to improve efficiency in water use, including use of lower quality water sources. A notable example is Eraring Energy which made a substantial investment in new water cooling processes.

Water use for electricity generation in Australia was examined in detail by Smart and Aspinall (2009)\textsuperscript{43}. All forms of electricity generation use water (see Table 1 below). Unsurprisingly, the use of water for hydro-electricity dwarfs that of other uses.

For all but hydroelectricity the cost of water is an essential but small component. Liberalisation of some water markets has meant that water can be allocated towards its most productive use, enabling generators to purchase additional water when required.\textsuperscript{44}

While prices will rise during a drought the cost impact for non-hydro-electricity generators is small. During the 2007/08 drought the price of bulk water (as measured by a temporary water trade) rose from around $100/ML to $800/ML. Using the data in Table 14 below, a $1000/ML increase in the cost of water would result in less than a $2 per MWh increase in the cost of producing electricity.

The availability of water may be more significant for hydro-electricity. Again, using Table 14 below, a $1000/ML increase in the bulk price of water would increase the cost (which might reflect opportunity cost) of electricity by almost $4,000 per MWh.

\textsuperscript{43} Alan Smart, Adam Aspinall 2009, Water and the electricity generation industry, Waterlines report, National Water Commission, Canberra

### Table 14: Water use and generation in 2004-05

<table>
<thead>
<tr>
<th>Generation type</th>
<th>GL</th>
<th>GWh</th>
<th>ML/GWh</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hydroelectricity</td>
<td>59,867</td>
<td>15,991</td>
<td>3,744</td>
</tr>
<tr>
<td>Black Coal</td>
<td>153</td>
<td>102,180</td>
<td>1.5</td>
</tr>
<tr>
<td>Brown Coal</td>
<td>82</td>
<td>54,041</td>
<td>1.52</td>
</tr>
<tr>
<td>Gas</td>
<td>12</td>
<td>20,786</td>
<td>0.56</td>
</tr>
<tr>
<td>Other</td>
<td>1</td>
<td>1,473</td>
<td>0.55</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>60,115</td>
<td>194,471</td>
<td></td>
</tr>
</tbody>
</table>

**Source:** Smart and Aspinall (2009)

The key hydroelectricity scheme in Australia is the Snowy Mountains River Scheme. This has a generating capacity of 3.95 GW and annual production of around 4.5GWH.  

**Energy use for water supply**

Water utilities are large energy users. During a drought the energy usage of water utilities may rise due to increased use of desalination facilities and/or increased pumping.

In recent years, large scale desalination plants have been built in Perth, Melbourne, Adelaide, Sydney and the Gold Coast. Desalination is heavily energy intensive. For example, the Wonthaggi (Melbourne) desalination plant requires 90MW when operating to:

- desalinate the salt water (power the pumps to create the pressure differential for reverse osmosis);
- transfer the very large volumes of salt water from the intakes to the plant and the brine back to the outlets; and
- transfer the desalinated water to storage facilities.

Water production is unlikely to be a significant factor for peak energy demand as water utilities have some flexibility in the timing of their energy use. Unlike energy, water can typically be stored cheaply in large quantities enabling water utilities to postpone operations when energy is expensive. For example, South Australia Water modifies its pumping times to coincide with lower energy prices. In Western Australia, WaterCorp is a provider of

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demand side management. Desalination plants typically have standby generation to maintain minimum operations and this plant could be used during peak demand periods.

**Economic impact of high demand during extreme heatwaves**

Figure 20 and Figure 21 show the association between annual maximum demand, peak wholesale prices, and heatwaves in South Australia and Victoria respectively, showing a period 30 days before and after the day of annual maximum demand of 2009 and 2014. While they show two summers corresponding to two key extreme heatwave events, the patterns are general to any year.

They show the strong correlation between high temperatures, especially heatwaves, demand peaks and price peaks. Demand peaks generally fall after a period of high maximum temperatures, and higher demand peaks and annual maximum demand occur when night-time temperatures are also elevated. Likewise, price peaks occur during these periods of high demand (considered as extended periods – this is not attempting to show or assert that demand and price peaks are correlated at the level of ½ hour trading intervals).

As a consequence of these correlations, these figures illustrate the basis for estimating the economic impact extreme heatwaves in terms of peak prices on wholesale electricity costs and demand peaks on network costs.

---

Figure 20 High demand in South Australia in 2009 and 2014

1. Daily maximum demand expressed as a percentage of annual maximum demand (AMD); daily maximum price expressed as a percentage of market price cap (MPC).
Figure 21 High demand in Victoria in 2009 and 2014

1. Daily maximum demand expressed as a percentage of annual maximum demand (AMD); daily maximum price expressed as a percentage of market price cap (MPC).

Wholesale energy costs

Table 15 and Table 16 provide, for Victoria and South Australia respectively, the total state demand volume weighted wholesale price for the two month period around annual maximum demand. Note this captures all peaks rather than those associated with a particular extreme heatwave event, however as demonstrated above these peaks are associated with heatwaves in general.

The volume weighted price has been calculated including and excluding price peaks in excess of $300, indicating the number of such trading intervals, and shows the premium for price peaks associated with heatwaves. This is volatile from year to year but ranges as high as 35 per cent in Victoria and 64 per cent in South Australia.
### Table 15 Heatwave wholesale price effect in Victoria

<table>
<thead>
<tr>
<th>FY</th>
<th>VW$</th>
<th># $ peaks</th>
<th>VW$ ex peaks</th>
<th>peak cost</th>
<th>Peak as per cent</th>
</tr>
</thead>
<tbody>
<tr>
<td>2000</td>
<td>$27.89</td>
<td>17</td>
<td>$26.81</td>
<td>$1.08</td>
<td>4%</td>
</tr>
<tr>
<td>2001</td>
<td>$48.56</td>
<td>105</td>
<td>$35.43</td>
<td>$13.12</td>
<td>27%</td>
</tr>
<tr>
<td>2002</td>
<td>$32.77</td>
<td>51</td>
<td>$27.57</td>
<td>$5.19</td>
<td>16%</td>
</tr>
<tr>
<td>2003</td>
<td>$29.62</td>
<td>31</td>
<td>$25.56</td>
<td>$4.06</td>
<td>14%</td>
</tr>
<tr>
<td>2004</td>
<td>$26.83</td>
<td>24</td>
<td>$25.27</td>
<td>$1.57</td>
<td>6%</td>
</tr>
<tr>
<td>2005</td>
<td>$28.80</td>
<td>15</td>
<td>$27.32</td>
<td>$1.47</td>
<td>5%</td>
</tr>
<tr>
<td>2006</td>
<td>$36.11</td>
<td>59</td>
<td>$27.35</td>
<td>$8.76</td>
<td>24%</td>
</tr>
<tr>
<td>2007</td>
<td>$60.55</td>
<td>106</td>
<td>$47.45</td>
<td>$13.10</td>
<td>22%</td>
</tr>
<tr>
<td>2008</td>
<td>$50.60</td>
<td>55</td>
<td>$46.38</td>
<td>$4.22</td>
<td>8%</td>
</tr>
<tr>
<td>2009</td>
<td>$49.10</td>
<td>38</td>
<td>$35.82</td>
<td>$13.27</td>
<td>27%</td>
</tr>
<tr>
<td>2010</td>
<td>$42.12</td>
<td>47</td>
<td>$27.38</td>
<td>$14.74</td>
<td>35%</td>
</tr>
<tr>
<td>2011</td>
<td>$29.12</td>
<td>12</td>
<td>$26.00</td>
<td>$3.12</td>
<td>11%</td>
</tr>
<tr>
<td>2012</td>
<td>$28.29</td>
<td>0</td>
<td>$28.29</td>
<td>$0.00</td>
<td>0%</td>
</tr>
<tr>
<td>2013</td>
<td>$60.81</td>
<td>30</td>
<td>$54.90</td>
<td>$5.90</td>
<td>10%</td>
</tr>
<tr>
<td>2014</td>
<td>$56.58</td>
<td>26</td>
<td>$51.50</td>
<td>$5.08</td>
<td>9%</td>
</tr>
<tr>
<td>Averages</td>
<td>$40.52</td>
<td>41</td>
<td>$34.20</td>
<td>$6.31</td>
<td>14.5%</td>
</tr>
</tbody>
</table>
### Table 16 Heatwave wholesale price effect in South Australia

<table>
<thead>
<tr>
<th>FY</th>
<th>VW$</th>
<th># $ peaks</th>
<th>VW$ ex peaks</th>
<th>peak cost</th>
<th>Peak as per cent</th>
</tr>
</thead>
<tbody>
<tr>
<td>2000</td>
<td>$68.97</td>
<td>100</td>
<td>$48.39</td>
<td>$20.58</td>
<td>30%</td>
</tr>
<tr>
<td>2001</td>
<td>$66.55</td>
<td>171</td>
<td>$42.62</td>
<td>$23.93</td>
<td>36%</td>
</tr>
<tr>
<td>2002</td>
<td>$33.50</td>
<td>43</td>
<td>$29.23</td>
<td>$4.26</td>
<td>13%</td>
</tr>
<tr>
<td>2003</td>
<td>$32.74</td>
<td>31</td>
<td>$29.74</td>
<td>$3.01</td>
<td>9%</td>
</tr>
<tr>
<td>2004</td>
<td>$39.31</td>
<td>47</td>
<td>$33.06</td>
<td>$6.25</td>
<td>16%</td>
</tr>
<tr>
<td>2005</td>
<td>$39.29</td>
<td>28</td>
<td>$34.15</td>
<td>$5.14</td>
<td>13%</td>
</tr>
<tr>
<td>2006</td>
<td>$44.04</td>
<td>81</td>
<td>$33.88</td>
<td>$10.17</td>
<td>23%</td>
</tr>
<tr>
<td>2007</td>
<td>$58.81</td>
<td>71</td>
<td>$50.62</td>
<td>$8.19</td>
<td>14%</td>
</tr>
<tr>
<td>2008</td>
<td>$101.15</td>
<td>99</td>
<td>$46.96</td>
<td>$54.19</td>
<td>54%</td>
</tr>
<tr>
<td>2009</td>
<td>$68.58</td>
<td>97</td>
<td>$36.87</td>
<td>$31.71</td>
<td>46%</td>
</tr>
<tr>
<td>2010</td>
<td>$82.51</td>
<td>88</td>
<td>$29.52</td>
<td>$52.99</td>
<td>64%</td>
</tr>
<tr>
<td>2011</td>
<td>$41.97</td>
<td>22</td>
<td>$27.20</td>
<td>$14.77</td>
<td>35%</td>
</tr>
<tr>
<td>2012</td>
<td>$32.05</td>
<td>12</td>
<td>$30.43</td>
<td>$1.62</td>
<td>5%</td>
</tr>
<tr>
<td>2013</td>
<td>$74.40</td>
<td>88</td>
<td>$63.69</td>
<td>$10.71</td>
<td>14%</td>
</tr>
<tr>
<td>2014</td>
<td>$74.68</td>
<td>73</td>
<td>$61.22</td>
<td>$13.46</td>
<td>18%</td>
</tr>
<tr>
<td>Averages</td>
<td>$57.24</td>
<td>70</td>
<td>$39.84</td>
<td>$17.40</td>
<td>26%</td>
</tr>
</tbody>
</table>

**Network costs**

The estimate of the network cost of demand peak is based on the incremental cost of providing network capacity for the top centile of capacity that is utilized for a fraction of one per cent of the year.

Figure 22 shows the load curves for Victoria and South Australia, illustrating for Victoria’s 2009 load curve the proportion of capacity utilization above 70/90 per cent of annual maximum demand.
Table 17 provides the load factors for these curves, the proportion of time the network is utilized above 70 per cent AMD and 90 per cent AMD, and the number of ½ hour intervals above 90 per cent AMD for the year, 2 month period and specific heatwave event.

**Table 17 load factors**

<table>
<thead>
<tr>
<th>State</th>
<th>Year</th>
<th>Load factor</th>
<th>70% AMD</th>
<th>90% AMD</th>
<th>½ hr intervals</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Year</td>
</tr>
<tr>
<td>VIC</td>
<td>2009</td>
<td>57%</td>
<td>6.9%</td>
<td>0.3%</td>
<td>50</td>
</tr>
<tr>
<td>VIC</td>
<td>2014</td>
<td>53%</td>
<td>3.3%</td>
<td>0.5%</td>
<td>72</td>
</tr>
<tr>
<td>SA</td>
<td>2009</td>
<td>46%</td>
<td>1.9%</td>
<td>0.3%</td>
<td>68</td>
</tr>
<tr>
<td>SA</td>
<td>2014</td>
<td>43%</td>
<td>1.5%</td>
<td>0.3%</td>
<td>40</td>
</tr>
</tbody>
</table>

Table 18 provides the estimated network cost for Victorian and South Australian networks. Ten per cent of regulated annual revenue is allocated to the cost of the top 10 per cent of capacity. The cost of this capacity is then allocated in proportion to the number of ½ hour intervals above 90 per cent AMD identified in Table 17.
Table 18 Network cost ($million)

<table>
<thead>
<tr>
<th>Network area</th>
<th>Annual revenue ($M)</th>
<th>Top 10% annual revenue</th>
<th>2009 heatwave</th>
<th>2014 heatwave</th>
</tr>
</thead>
<tbody>
<tr>
<td>Powercor</td>
<td>500</td>
<td>50</td>
<td>49</td>
<td>42</td>
</tr>
<tr>
<td>SP AusNet (D)</td>
<td>481</td>
<td>48.1</td>
<td>47</td>
<td>40</td>
</tr>
<tr>
<td>United Energy</td>
<td>328</td>
<td>32.8</td>
<td>32</td>
<td>27</td>
</tr>
<tr>
<td>CitiPower</td>
<td>235</td>
<td>23.5</td>
<td>23</td>
<td>20</td>
</tr>
<tr>
<td>Jemena</td>
<td>201</td>
<td>20.1</td>
<td>20</td>
<td>17</td>
</tr>
<tr>
<td>SP AusNet (T)</td>
<td>501</td>
<td>50.1</td>
<td>49</td>
<td>42</td>
</tr>
<tr>
<td>Victoria</td>
<td>2,246</td>
<td>224.6</td>
<td>220</td>
<td>187</td>
</tr>
<tr>
<td>SAPN</td>
<td>494</td>
<td>49.4</td>
<td>47</td>
<td>36</td>
</tr>
<tr>
<td>ElectraNet</td>
<td>286</td>
<td>28.6</td>
<td>27</td>
<td>21</td>
</tr>
<tr>
<td>South Australia</td>
<td>780</td>
<td>78.0</td>
<td>73</td>
<td>57</td>
</tr>
</tbody>
</table>

Further information on scenario approach

AEMO demand scenarios

AEMO develops its annual energy and demand (MD) forecasts using three forecast scenarios. For the 2014 NEFR, the scenarios used in the 2012 and 2013 NEFRs were revised. All three AEMO demand scenarios incorporate an additional variable to reflect the increasing frequency and severity of extreme heatwaves.

The 2014 scenarios represent high, medium, and low energy consumption of electricity from a centralised source (the national grid). This is a significant shift away from the previous NEFR scenarios, and reflects the increasing impact of local generation and energy efficiency.

The scenarios are designed to reflect different levels of economic growth, residential and commercial consumption, large industrial consumption, rooftop PV output, energy efficiency and small non-scheduled generation (SNSG).

Key assumptions in the medium scenario include:
• Electricity price increases would be moderate.
• Australia’s economic activity and population growth continue at current levels
• Energy intensive industrial and manufacturing sectors continue at their current energy consumption levels, but publicly announced changes in operations are included.
• Distributed generation penetration is moderate.
• Demand side response levels continue as current – the potential impact of proposed demand side pricing and related reforms are excluded.
• Carbon policy is implemented only via a reverse auction component of the government’s Direct Action policy.
• The renewable energy targets are assumed to remain, pending the 2014 RET review.

Key assumptions in the high scenario relative to the medium scenario include:
• Electricity price increases would be lower than in the medium scenario.
• There is a higher level of Australian and global economic activity than in the medium scenario and a higher level of population growth.
• Energy intensive industrial sectors increase their output levels.
• Domestic gas production is higher but it is assumed that gas substitution is limited due to switching costs.
• Distributed generation investment is lower than in the medium scenario.
• Consumer support for demand side response is dampened, with reduced uptake of small scale distributed generation and energy efficiency.
• Demand side response is weaker.
• Maximum demand occurs earlier in the day in South Australia.

Key assumptions in the low demand scenario include:
• Electricity prices would rise significantly.
• There is a lower level of domestic and international economic activity than in the medium scenario
• Energy intensive industrial sectors, including smelters and manufacturers, decrease their output
• There is a lower rate of population growth
• Domestic gas production is lower than expected, but fuel substitution hurdles discourage fuel switching between electricity and gas
• Global LNG demand is weaker than in the medium scenario and there is a low penetration of gas as a transport fuel
• Relative to the other scenarios, there is a stronger move toward distributed generation
• Maximum demand occurs later in the day in South Australia.

**Forecast generation capacity mix**
The forecast firm scheduled generation capacity mix is set out in Table 19 below.
### Table 19 Forecast capacity mix by State for 2018/19

<table>
<thead>
<tr>
<th>Generation type</th>
<th>Qld</th>
<th>NSW</th>
<th>Vic</th>
<th>SA</th>
<th>Tas</th>
<th>NEM</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal</td>
<td>7,373</td>
<td>10,425</td>
<td>6,130</td>
<td>0</td>
<td>0</td>
<td>23,928</td>
</tr>
<tr>
<td>Gas</td>
<td>3,086</td>
<td>2,082</td>
<td>2,175</td>
<td>2,649</td>
<td>386</td>
<td>10,377</td>
</tr>
<tr>
<td>Hydro</td>
<td>652</td>
<td>2,833</td>
<td>2,194</td>
<td>0</td>
<td>2,102</td>
<td>7,781</td>
</tr>
<tr>
<td>Firm wind</td>
<td>7</td>
<td>20</td>
<td>146</td>
<td>136</td>
<td>32</td>
<td>342</td>
</tr>
<tr>
<td>Firm solar (large)</td>
<td>11</td>
<td>93</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>104</td>
</tr>
<tr>
<td>Firm operational supply</td>
<td>11,130</td>
<td>15,452</td>
<td>10,644</td>
<td>3,017</td>
<td>2,520</td>
<td>42,751</td>
</tr>
</tbody>
</table>

Note this excludes SNSG, rooftop PV and includes only firm wind. It also excludes generation that is offline.

The supply capacity forecast includes new wind capacity that was committed at the cut-off date for the 2013 ESO. A notable feature of the capacity mix is the very low capacity attributed to Semi Scheduled (large) wind capacity for the purpose of forecasting firm capacity.

Transmission capacity between NEM regions – interconnectors – enable the sharing of energy, capacity and reserves between regions. As highlighted in the January 2014 event, imports from interconnectors can avoid reliability or supply shortfalls.
Table 20 below provides interconnector capacity during summer peak demand.
Table 20 Interconnector capacity

<table>
<thead>
<tr>
<th>Interconnector</th>
<th>From region</th>
<th>To region</th>
<th>Summer Peak</th>
</tr>
</thead>
<tbody>
<tr>
<td>QNI</td>
<td>QLD</td>
<td>NSW</td>
<td>1078</td>
</tr>
<tr>
<td>QNI</td>
<td>NSW</td>
<td>QLD</td>
<td>400</td>
</tr>
<tr>
<td>Snowy</td>
<td>NSW</td>
<td>VIC</td>
<td>237.5</td>
</tr>
<tr>
<td>Snowy</td>
<td>VIC</td>
<td>NSW</td>
<td>784</td>
</tr>
<tr>
<td>Heywood</td>
<td>VIC</td>
<td>SA</td>
<td>460</td>
</tr>
<tr>
<td>Heywood</td>
<td>SA</td>
<td>VIC</td>
<td>460</td>
</tr>
<tr>
<td>Murraylink</td>
<td>VIC</td>
<td>South Australia</td>
<td>50 (220)</td>
</tr>
<tr>
<td>Murraylink</td>
<td>SA</td>
<td>VIC</td>
<td>50 (160)</td>
</tr>
<tr>
<td>Terranora</td>
<td>QLD</td>
<td>NSW</td>
<td>224</td>
</tr>
<tr>
<td>Terranora</td>
<td>NSW</td>
<td>QLD</td>
<td>107</td>
</tr>
<tr>
<td>Basslink</td>
<td>VIC</td>
<td>TAS</td>
<td>478</td>
</tr>
<tr>
<td>Basslink</td>
<td>TAS</td>
<td>VIC</td>
<td>594</td>
</tr>
</tbody>
</table>

Source: AEMO

1. AEMO's advised that while the summer peak ratings for Murraylink are higher, network congestion in north west Victoria and north east South Australia due to summer demand applies an effective limit of 50MW in each direction.

Heatwave scenario outcomes

This section provides a full suite of modelled scenario outcomes, beyond the three key outcomes reported in section five above (which is also included below).

Stressor scenario

The Table below shows the overall supply demand balance in a stressor 2019 scenario. This indicates a substantial operational deficit in Victoria and a smaller but still significant deficit in South Australia.
Table 21 Supply-demand balance for stressor February 2019 heatwave scenario

<table>
<thead>
<tr>
<th>MW</th>
<th>QLD</th>
<th>NSW</th>
<th>VIC</th>
<th>SA</th>
<th>TAS</th>
</tr>
</thead>
<tbody>
<tr>
<td>Demand</td>
<td>10,127</td>
<td>15,049</td>
<td>11,029</td>
<td>3,391</td>
<td>1,579</td>
</tr>
<tr>
<td>Generation</td>
<td>11,130</td>
<td>15,456</td>
<td>9,819</td>
<td>2,833</td>
<td>2,528</td>
</tr>
<tr>
<td>Net imports</td>
<td>0</td>
<td>-238</td>
<td>322</td>
<td>510</td>
<td>-594</td>
</tr>
<tr>
<td>Balance</td>
<td>1,002</td>
<td>170</td>
<td>-889</td>
<td>-48</td>
<td>356</td>
</tr>
<tr>
<td>Interconnector utilisation</td>
<td>0%</td>
<td>100%</td>
<td>100%</td>
<td>100%</td>
<td></td>
</tr>
</tbody>
</table>

Source: Sapere analysis

Return of offline generation
The Table below shows the impact of returning offline capacity. The impact is most limited in Victoria. While the impact is highest in NSW, the benefit for Victoria (and South Australia) is limited due to interconnector congestion.

Table 22 Stressor supply-demand balance – with return of offline capacity

<table>
<thead>
<tr>
<th>MW</th>
<th>QLD</th>
<th>NSW</th>
<th>VIC</th>
<th>SA</th>
<th>TAS</th>
</tr>
</thead>
<tbody>
<tr>
<td>Native demand</td>
<td>10,127</td>
<td>15,049</td>
<td>11,029</td>
<td>3,391</td>
<td>1,579</td>
</tr>
<tr>
<td>Native generation</td>
<td>12,405</td>
<td>15,956</td>
<td>9,914</td>
<td>3,251</td>
<td>2,528</td>
</tr>
<tr>
<td>Net imports</td>
<td>0</td>
<td>-238</td>
<td>394</td>
<td>140</td>
<td>-297</td>
</tr>
<tr>
<td>Balance</td>
<td>2,277</td>
<td>670</td>
<td>-721</td>
<td>0</td>
<td>653</td>
</tr>
</tbody>
</table>

Impact of wind
In the cases outlined above, it is assumed that wind makes a very modest contribution to supply during the 2019 heatwave, corresponding to the average wind output during the 2014 heatwave.
Wind output during part of the 2014 heatwave was significantly higher than the average output over the period. In addition, the major forecast change in generation capacity between 2014 and 2019 is increased wind capacity.

If this higher value is applied, alongside committed additional wind capacity, then there is no supply shortfall, as shown in the Table below. In particular, South Australia’s balance improves materially.

Table 23 Stressor supply-demand balance – with higher firm wind, return of offline plant and impaired Basslink and Heywood

<table>
<thead>
<tr>
<th>MW</th>
<th>QLD</th>
<th>NSW</th>
<th>VIC</th>
<th>SA</th>
<th>TAS</th>
</tr>
</thead>
<tbody>
<tr>
<td>Demand</td>
<td>10,127</td>
<td>15,049</td>
<td>11,029</td>
<td>3,391</td>
<td>1,579</td>
</tr>
<tr>
<td>Generation</td>
<td>12,456</td>
<td>16,122</td>
<td>11,118</td>
<td>4,448</td>
<td>2,817</td>
</tr>
<tr>
<td>Net imports</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Balance</td>
<td>2,329</td>
<td>1,073</td>
<td>89</td>
<td>1,057</td>
<td>1,238</td>
</tr>
</tbody>
</table>

Alternative stressor scenario

The Table below provides an alternative stressor scenario. In this case, offline generation is returned to service, and higher firm wind output is assumed. In addition:

- The Heywood interconnector is assumed to be offline for an extended period, resulting in a loss of 460MW of imports into South Australia.
- The Basslink interconnector is constrained for an extended period, resulting in a halving of capacity from 594MW to 297MW.
Table 24 Alternative stressor scenario— with higher firm wind, return of offline plant and impaired Basslink and Heywood

<table>
<thead>
<tr>
<th>MW</th>
<th>QLD</th>
<th>NSW</th>
<th>VIC</th>
<th>SA</th>
<th>TAS</th>
</tr>
</thead>
<tbody>
<tr>
<td>Demand</td>
<td>10,127</td>
<td>15,049</td>
<td>11,029</td>
<td>3,391</td>
<td>1,579</td>
</tr>
<tr>
<td>Generation</td>
<td>12,456</td>
<td>16,122</td>
<td>11,118</td>
<td>4,448</td>
<td>2,817</td>
</tr>
<tr>
<td>Net imports</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Balance</td>
<td>2,329</td>
<td>1,073</td>
<td>89</td>
<td>1,057</td>
<td>1,238</td>
</tr>
</tbody>
</table>

Impact of Snowy interconnector outage
Section three identified the significant impact of an outage to the Snowy interconnector. Table 25 below highlights that if an outage to the Snowy interconnector is added to the alternative stress scenario (but with all offline generation returned to service), then Victoria would experience a substantial shortfall, and South Australia would also have insufficient supply capacity. The likely outcome would be extensive outages.

Table 25 Impact of Snowy interconnector outage under alternative scenario

<table>
<thead>
<tr>
<th>MW</th>
<th>QLD</th>
<th>NSW</th>
<th>VIC</th>
<th>SA</th>
<th>TAS</th>
</tr>
</thead>
<tbody>
<tr>
<td>Demand</td>
<td>10,127</td>
<td>15,049</td>
<td>11,029</td>
<td>3,391</td>
<td>1,579</td>
</tr>
<tr>
<td>Generation</td>
<td>12,456</td>
<td>16,122</td>
<td>11,118</td>
<td>4,448</td>
<td>2,817</td>
</tr>
<tr>
<td>Net imports</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Balance</td>
<td>2,329</td>
<td>1,073</td>
<td>89</td>
<td>1,057</td>
<td>1,238</td>
</tr>
</tbody>
</table>

Impact of alternative AEMO demand scenarios
All the modelled results above apply the AEMO’s high demand scenario. Table 26 below shows the relative impact of applying the AEMO’s medium demand scenario. This suggests there could be a shortfall in South Australia and low reserves in Victoria.
### Table 26 Stressor supply-demand balance – with AEMO medium demand scenario

<table>
<thead>
<tr>
<th>MW</th>
<th>QLD</th>
<th>NSW</th>
<th>VIC</th>
<th>SA</th>
<th>TAS</th>
</tr>
</thead>
<tbody>
<tr>
<td>Demand</td>
<td>8,984</td>
<td>13,614</td>
<td>9,874</td>
<td>3,179</td>
<td>1,103</td>
</tr>
<tr>
<td>Generation</td>
<td>11,130</td>
<td>15,456</td>
<td>9,819</td>
<td>2,833</td>
<td>2,528</td>
</tr>
<tr>
<td>Net imports</td>
<td>0</td>
<td>-58</td>
<td>55</td>
<td>300</td>
<td>-297</td>
</tr>
<tr>
<td>Balance</td>
<td>2,146</td>
<td>1,784</td>
<td>0</td>
<td>-47</td>
<td>1,129</td>
</tr>
<tr>
<td>Interconnect or utilisation</td>
<td>0%</td>
<td>24%</td>
<td>100%</td>
<td>100%</td>
<td></td>
</tr>
</tbody>
</table>

Table 27 below shows the relative impact of applying the AEMO’s low demand scenario under the alternative stress scenario. This suggests that, even with offline capacity remaining offline, and technical constraints on both Heywood and Basslink, there are positive balances in each region.

### Table 27 Alternative scenario, with AEMO low demand scenario and no return of offline generation

<table>
<thead>
<tr>
<th>MW</th>
<th>QLD</th>
<th>NSW</th>
<th>VIC</th>
<th>SA</th>
<th>TAS</th>
</tr>
</thead>
<tbody>
<tr>
<td>Demand</td>
<td>8,984</td>
<td>13,614</td>
<td>9,874</td>
<td>3,179</td>
<td>1,103</td>
</tr>
<tr>
<td>Generation</td>
<td>11,181</td>
<td>15,622</td>
<td>11,023</td>
<td>4,030</td>
<td>2,817</td>
</tr>
<tr>
<td>Net imports</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Balance</td>
<td>2,197</td>
<td>2,008</td>
<td>1,149</td>
<td>851</td>
<td>1,714</td>
</tr>
</tbody>
</table>