& RUSS SKELTON ASSOCIATES

Review of the System Restart Standard

A Submission to Reliability Panel AEMC

Prepared on behalf of:

Snowy Hydro Limited
Alcoa of Australia
CS Energy
AGL Energy
Tomago Aluminium Company
Origin Energy

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Submission to AEMC Reliability Panel in response to:

"Review of the System Restart Standard"

Executive summary

This submission is in response the Reliability Panel's Issues Paper, "Review of the System Restart Standard".

Modern economies rely greatly on a highly reliable electricity supply. In general this reliability is achieved, however major black outs have occurred and the impact of these have been significant. For example the black out that occurred in Northeast United States and Southeast Canada on 14 August 2003 affected more than 50 million people, lasted for more than 2 days and had an economic cost of around $US 6 billion. Similar black outs have occurred in The USA, Europe and at a smaller scale in Australia.

The risk of such an event occurring in Australia is real and the historical absence of a major black out does not mean this risk is not existent. In fact it could be argued that with changing climatic conditions and structural changes in the National Electricity Market (NEM) with the greater reliance on wind and solar generation that the risk of major black outs is increasing.

The primary cause of black outs is incidents on the transmission network that can be caused by:

- Natural events – such as floods, cyclones and bushfires.
- Man made events – such as terrorism or cyber security.
- Technical events – such as the failure of the system to respond adequately to normal occurrences such as generator trips.

To mitigate the risk of major black outs black start services are provided in the NEM which make it possible to restore supplies to customers. These include arrangements for generators to be available to start without the need for an external supply, other generators to be supplied over the network to enable them to restart and then be connected to load and begin restoring supply to customers.

Given the very unusual circumstances that will prevail during a system black, this restoration process is challenging and risky.

It is likely that black start providers will fail to perform as expected. This is demonstrated by international experience with a common source of black start "Trip to House Load".

Also generators' restarting is a risky process and the time that a generator is most likely to trip is in the first few hours of operation during and after a return to service.

For generators to restart and for customers to have supply restored requires system and network operators operating the system in an unusual and difficult manner. This will create challenges and risks that imply the network restoration task will almost inevitably not go to plan and this will result in unexpected delays in restoring customers.

However even if it is assumed that system restoration goes to plan, based on experience gained from annual restoration simulation exercises in NSW it is apparent that the restoration times that are expected to be achieved are greater than required by the current System Restart Standard and are very likely to result in significant disruption to electricity consumers and the economy. This is illustrated by the likely permanent shut down of aluminium smelters as a result of a major black out.

There are three major concerns with the current arrangements. Firstly, the current arrangements do not take into account the risks for black start providers, generators relying on them and the network and system operations required to restore load. Secondly, the form of the standard is focused on intermediate outcomes, not the final restoration of load. Finally, the standard is largely derived on a technical basis rather than accounting for the economic trade off between the incremental benefits of improving the expected time for restoration of load compared to the incremental costs of achieving this by recruiting higher levels of System Restart Ancillary Service (SRAS) and associated services.

This report highlights our concerns with the current form of the standard and its implementation and presents a number of recommendations for improving outcomes for all consumers.

The key recommendations are:

1. The System Restart Standard (SRS) should define the outcomes required in terms of the time to restore a defined quantity of load with a defined reliability. This would require that System Restart Ancillary Services encompass not only generators that can restart without an external supply but the performance of other generators and also network providers that would be required to provide supply to customers with the specified time frame.
2. That rather than this SRS being uniform across all sub-regions that the standard can vary from sub-region to sub-region.
3. Sub-regions for the purposes of applying the SRS should be determined primarily on the basis of the economic characteristics of the load within a region, including whether any of the loads are considered sensitive. The technical characteristics of the region being an important but secondary consideration.
4. The Restart Standard that applies to each sub-region be determined on the basis of an economic trade-off between the costs of the provision of additional SRAS compared to the additional benefits to customers in terms of reduced restoration times and reliability with which these can be achieved.
5. To improve the validation of AEMO's compliance with the SRS, that AEMO be required to provide much more transparency on how it has implemented the SRS.

The new provisions in the National Electricity Rules provide the legal framework necessary for the implementation of these recommendations.

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Introduction

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1. Snowy Hydro Limited
2. Alcoa of Australia
3. CS Energy
4. AGL Energy
5. Tomago Aluminium Company
6. Origin Energy

The submission is in response to the Issues Paper, "Review of the System Restart Standard" published by the Reliability Panel AEMC on 19 November 2015.

This report was prepared collaboratively by:

James Beckwith of James Beckwith Consulting;
Neil Smith of Neil Smith & Associates;
Graeme Dennis of Clayton Utz;
James Allan of Frontier Economics; and
Russ Skelton of Russ Skelton & Associates

Background

What can go wrong

International and Australian experience

The electricity supply systems in modern economies are highly reliable and these economies are highly dependent on this reliability being maintained. However these systems can fail and major black outs can occur.

Examples of these failures include:

1. Northeast United States and Southeast Canada on 14 August 2003. [1]

   This black out affected more than 50 million people and load was not fully restored for more than 2 days. Estimates of the economic cost of this black out range from $US4 billion to $US10 billion. The US Department of Energy estimated the cost at $US6 billion.

2. Northeast United States on 9 November 1965.[2]

   This black out affected 30 million people with outages lasting for up to 13 hours.

3. New York City on 13 July 1977.[2]

   This black out affected 9 million people with outages lasting up to 26 hours.

4. A range of smaller black outs across the US in 1982, 1996 twice and 1998.[2]

   These black outs affected 5 million, 2 million, 7.5 million and 152,000 people and lasted from a few minutes for some customers to up to 9 hours for others.

[1] ELCON (2004), The Economic Impacts of the August 2003 Blackout, Electricity Consumers Resource Council
[2] US-Canada Power System Outage Task Force (2004), August 14, 2003 Blackout: Causes and Recommendations

5. Italy and parts of Switzerland on 28 September 2003.[3]

   This black out affected around 55 million people. Fifty percent of load was reconnected after 6.5 hours with services being completely restored to all consumers 18 hours after the black out commenced. The economic cost was estimated to be around $US139 million.

6. Sweden and Denmark on 12 September 2004.[3]

   This black out affected about 4 million people and full restoration of supply was achieved after about 6 hours. The economic cost was estimated to be around $US301 million.

7. Australia on 13 August 2004.[3]

   As the result of a failure of a current transformer in the switchyard at Bayswater Power Station 3 units at Bayswater were tripped. This led other generator trips and to automatic load shedding of over 1,500 MW of load across the National Electricity Market (NEM). This affected about 250,000 customers including a smelter in Queensland. Load was fully restored around 80 minutes after the initial failure using sources other than Bayswater.

8. Australia on 2 July 2009.[4]

   As the result of a failure of a current transformer in the switchyard at Bayswater Power Station all units at Bayswater were tripped. Other generation units were also tripped resulting in a total of 3,205 MW being lost. This led to automatic load shedding of 1,131MW of load. This load was largely restored within about 1 hour of the initial failure using sources other than Bayswater.

9. Australia on 1 November 2015.[5]

   As the result of a circuit breaker trip on the Heywood interconnector, a low frequency event led to 150 MW of load shedding in South Australia. Load restoration was completed within approximately 1.5 hours.

These incidents are examples of what has occurred historically. For a more complete and detailed record refer to the report to the National Generators Forum (NGF) and the Private Generators Group (PGG) prepared by ROAM Consulting. [6]

In reviewing the international experience it is interesting to note that in the Switzerland and Italy failures that *"31 thermal units initiated the sequence to switch to in-house operating mode prior to system collapse. However only 8 of the plants completed the sequence, allowing them to remain in operation after the collapse and to provide immediate support for restart activities"*.[3] Again in the Sweden and Denmark failure that *"Restoration of load may have been achieved more quickly if some of east Denmark's large generators successfully switched to in-house operation. Four of ten succeeded temporarily but subsequently failed when the final voltage collapse occurred"* [3]

The success of trip to house schemes (as it is termed in Australia) was very low. In aggregate of the 41 units that commenced the process of tripping to house only 8 succeeded. This is a success rate of less than 20%. This success rating is particularly concerning given that a number of SRAS providers in the NEM are trip to house load schemes.

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[3] International Energy Agency (2005), Learning from the Blackouts

[4] AEMO (2009), Multiple Generator and Under Frequency Load Shedding, Thursday 2nd July 2009

[5] AEMO (2015), Price Event Report, 1 November 2015.
Weblink: http://www.aemo.com.au/Electricity/Resources/Reports-and-Documents/Pricing-Event-Reports/November-2015

[6] ROAM Consulting (2014), Review of System Restart Ancillary Service Requirements in the NEM

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Transmission system events that could trigger a major black out

Transmission system events that could trigger a major black out can be considered in 3 broad categories:

1. Natural events
2. Man-Made events
3. Technical events

Natural events

Around the world, the following natural events have been known to bring about major system incidents:

- Earthquake
- Extreme weather event – flooding
- Extreme weather event – cyclone
- Extreme weather event - microburst
- Bushfires
- Lightning
- Geomagnetically Induced Currents (GIC).

Earthquake

Although there has been seismic activity recorded in Australia, and in some limited cases this has led to generator trips, this has always been of relatively minor significance compared to, for example, New Zealand, where substation equipment is fitted with "seismic restraints" to prevent movement. However an earthquake on 19 June 2012 did cause three units at Loy Yang A power station to trip with no system impact.

Risk of earthquake

Earthquake is currently regarded as a low probability event, unlikely to change with time.

Flooding

As was witnessed in the Brisbane area during the period Dec 2010 to Feb 2011, widespread flooding can have a huge impact on power networks. In this particular instance, the probability of flooding was known beforehand and the affected distribution network was closed down in a controlled way, and then restored progressively as the flooding receded. Less publicised was the damage done to the transmission network, with some towers washed away and others dangerously undermined, leaving the network in a precarious state whilst surveys and emergency repairs were carried out. Events of this nature clearly have the propensity to cause a system shutdown.

Risk of flooding

Flooding is regarded as a higher probability event across most of Australia. The advice from the Bureau of Meteorology (BoM) is that such extreme weather events are likely to become more frequent as the climate enters a more unstable period.

Cyclone

Cyclone events have usually confined themselves to the northern parts of Queensland. The damage done is frequently catastrophic, with anything near the eye of the storm being destroyed. A recent example of this was Tropical Cyclone Yasi in Feb 2011, which came ashore as a Category 5 cyclone and completely flattened parts of the transmission network.

Risk of cyclone

The forecast trend for such events is to be of increasing frequency and generally progressing further south. This will put much larger areas of the network at risk.

Microburst

Microbursts usually occur in remote areas and are seldom witnessed so were thought to only occur rarely. The affected area is usually small, with a clear touch-down point and a line of complete destruction. Whilst it might be considered unlikely that such a phenomenon might impact a power network, in 2011 the single 220kV transmission line to Broken Hill was affected and several steel towers flattened.

Risk of microburst

This is a type of extreme weather event that can be expected to become more frequent.

Bushfires

Bushfires are an accepted part of the Australian landscape. Traditionally, transmission networks have shown high degrees of resilience to such activity and the extent of any associated power disruption has been largely due to the policy adopted by the affected Transmission Network Service Provider (TNSP) regarding the reclosure of tripped lines. These policies vary considerably from state to state; at one end of the spectrum, a TNSP would attempt a reclose on a line after allowing a “reasonable” time (~ 15 minutes) for the bushfire to pass through. Others would wait until a patrol had confirmed that a line was not on the ground and it was safe to re-energise. At the other end of the spectrum, one TNSP would elect to de-energise certain lines if it was known that bushfires were in the vicinity, regardless of the impact.

This wide breadth of policies significantly affects the resilience of networks, particularly if bushfires are affecting more than one part of the network at once.

Risk of bushfires

Bushfire events have been becoming more extreme in recent years, with widespread damage to transmission assets caused by localised windstorms associated with the intense heat. The forecast from the BoM is that these events will become more frequent and even more intense, so significant damage to assets can be anticipated on a regular basis.

Lightning

Lightning storms are commonplace during certain seasons and, to a degree, networks are designed to withstand lightning without incurring excessive damage. Lightning frequently leads to circuit tripping, with reclosing issues similar to those mentioned under bushfires. During intense storms affecting widespread areas, it is possible that a number of circuits can be out of service simultaneously before AEMO has resecured the network. Insecure operation can lead to multiple circuit tripping and cascading events.

Risk of lightning

Lightning may be anticipated to become more frequent / intense as the climate enters a more unstable period.

Geomagnetically Induced Currents (GIC)

GIC are caused by solar flares associated with sunspot activity. This activity occurs on an 11-year cycle, with the last peak in 2013. This activity can seriously impact transmission networks, most notably causing serious issues in North America and Canada. The nature of this phenomenon is that it is most problematic above latitudes of 40^{o}. Theoretically this could have an impact on Tasmania, but measurements taken during the 2013 peak period did not correspond with any system issues.

Risk of GIC

With sunspot activity now in the declining part of the cycle, it is reasonable to say that this does not appear to pose a serious risk of system shutdown.

Man-made events

These events fall into two sub-categories, Deliberate and Inadvertent:

Deliberate Events

- Terrorist activity
- Cyber Security event

Terrorist activity

Whilst power networks have not been the subject of many terrorist attacks, it would be unwise to disregard the potential threat. In the late 1990's, in the UK a terrorist plot was foiled which planned to blow up all of the large transformers feeding into London. The terrorists knew the exact location of the substations and the corresponding impact. If successful, London would have been on rolling black outs for several months as new equipment was procured and installed.

Terrorist organisations are becoming more sophisticated. It is not unlikely that infrastructure could become the next target, with easy access in remote areas.

Risk of terrorist activity

ASIO has declared that Australia is currently at a High Level of alert, with a threat level of "probable". It does not seem likely that this will diminish in the foreseeable future.

Cyber security event

"Cyber terrorism" has become recognised as a threat to any network. Most TNSPs have systems in place that allow minimal external interfacing, which will prevent the "Schoolboy hacker" attacks. However, more sophisticated terrorists with better resources can "hack" using different ways into the cyber network than just the Internet. Internationally, a number of cyber security events have been attributable to people with "inside access", usually disgruntled staff members. Various commercial systems have been developed to monitor "unusual activity" on a system, and then produce a warning, as well as preventing any access by unauthorised persons.

Risk of cyber security event

This particular threat is taken very seriously by TNSPs and, similar to other terrorist activity, is unlikely to diminish in the foreseeable future.

Inadvertent events

- Incorrect operation of equipment ("human error")
- Inadequate emergency management procedures (including training)

Human error

"Human Error" covers everything from a protection technician applying an incorrect setting, through to the system operator opening the wrong circuit breaker. Whilst this is not an uncommon occurrence, the impact is usually only of limited extent. However, it does have the propensity to become very serious under some circumstances.

Emergency procedures

These are listed under "inadvertent events" because most organisations believe their procedures are adequate until a real event proves otherwise. Whilst virtually all organisations have some kind of emergency management procedures, review of world-wide system events shows that sometimes these are completely inadequate and of no use to the operator during an emergency. Prior to the August 2003 shutdown in North America, most utilities regarded staff training as an unnecessary expense. Operations staff training in Australia is very variable across organisations.

Risk of failure of emergency procedures

It is reasonable to assume that organisations with a strong commitment to staff training and emergency management will fare much better than others who don't. However, to put this into perspective, on average bushfires plus lightning account for approximately 90% of circuit trips. The next biggest contributor is Human Error.

Technical events

Whilst electricity networks had remained unchanged for a period of about 40 years, a number of changes are now occurring that are already beginning to present technical challenges.

The main issue is the rise of renewable generation, mainly in the form of wind or solar power. Both of these are non-synchronous, using inverters to convert the power they produce into the frequency required by the network. For this to function correctly, the non-synchronous generation requires a stable system that in turn requires a certain amount of inertia, usually provided by spinning synchronous generators fuelled by coal, gas or hydro.

As the amount of non-synchronous generation increases, a corresponding amount of fossil-generation is displaced and will either be left running at low load (inefficient) or shut down altogether (reducing the total inertia on the system). There is a point where there is insufficient inertia on the network for it to continue operating stably, with corresponding power swings, circuit overloads and cascade tripping.

Renewable generation also poses challenges due to its intermittency. Forecast output for renewable generation is only as good as the corresponding weather forecast. Covering this variability is becoming a serious issue already in Australia, with South Australia now heavily dependent on renewable generation for supplying consumers, but heavily dependent on its connection with Victoria to provide the required inertia for stable operation.

Risk of technical events

The uptake of renewables is expected to increase in the coming years. This will change the shape of the electricity supply industry. If the technical issues associated with this change are not acknowledged and properly addressed the risk of technical events leading to major black outs will increase – potentially significantly. The availability of inertia is an essential component of the network, however the importance of this is not yet fully acknowledged. This is demonstrated by the fact that currently the provision of inertia is not defined as a necessary ancillary service as are other essential services such as frequency response and SRAS.

Given the high level of wind generation in South Australia, the risk of black outs due to inadequate levels of inertia is real and will increase even further when Northern Power Station is retired from service.

Generation events that could trigger a major black out

In general the events that trigger major black outs occur in the transmission system. However in the last 20-30 years there have been a number of instances of major generator failures which in some instances led to black outs.

Two of these, involving Bayswater power station are referred to above. Both of these events however were triggered by failures in the Bayswater switchyard.

In addition to these events some initiated solely within the power station are:

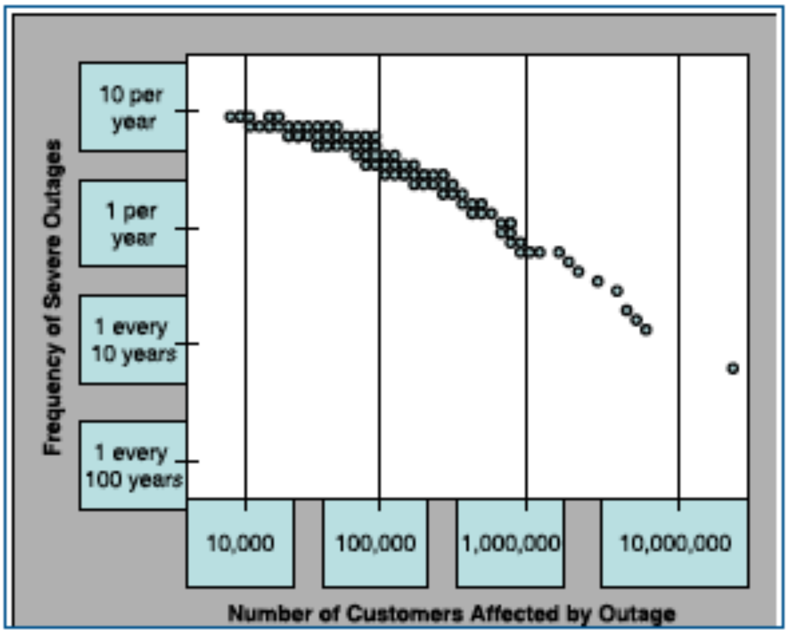
- Loss of all units at Eraring early in 1990's as the result of a failure of the station compressed air systems.
- Loss of both units at Vales Point power station as the result of a generator transformer explosion

Risk of major black outs

Estimating the probability of a major black out is obviously challenging.

ROAM Consulting in their report to NGF and NPP, based on their research and analysis provides estimates of the risk of various sized black outs. For example they estimate that the probability of a black out of NSW being about once every 27.5 years. [6]

The following graph from a report on the US Canada failure in 2003 [2] indicates that major black outs, that is in excess of 5 million customers, could be expected once every 10 years.



Note: The circles represent individual outages in North America between 1984 and 1997, plotted against the frequency of outages of equal or greater size over that period.

Source: Adapted from John Doyle, California Institute of Technology, "Complexity and Robustness," 1999. Data from NERC.

The risk of a major black out in Australia in the future is likely to be affected by:

- Declining electricity demand which is potentially reducing the risk of black outs as the transmission system is less stressed
- Weather-related events which are becoming more extreme
- The increasing risk and severity of bushfires which are likely to impact on transmission systems
- The increasing amount of wind generation and intermittent generation more generally (including solar PV) combined with the associated reduction in thermal generation. This results in a significant reduction in the amount of inertia available to the power system and increases the risk of major black outs. This is particularly the case in South Australia.

Based on the analysis by ROAM, other estimates and these factors, a pragmatic estimate would be to plan for a major black out in the NEM once in every 20 to 30 years. This means that it is a real risk and that appropriate arrangements should be put in place to mitigate the risk of it occurring and limiting the consequences when it occurs.

Restoration challenges

Restoration of the power system in the event of a major black out creates major challenges for:

- Providers of SRAS
- Generators relying on SRAS providers
- The transmission system

Challenges for SRAS or black start providers

Black start capability comes in a number of forms and/or combinations:

- Market facing open cycle gas turbine generation that can self-start without needing external supplies. Examples are medium sized gas turbines (e.g. Colongra and Jeeralang) which are fitted with equipment capable of running the main gas turbine to firing speed, then firing to bring the turbine up to synchronous speed in readiness for connection to the network;
- Market facing hydro plant that can self-start without needing external supplies to operate hydraulic pumps and guide vanes to run the turbine/generator to synchronous speed;
- Small embedded open cycle gas turbine generation that can self-start without needing external supplies which supply electrical energy directly to a baseload coal-fired generator via a private or public network to enable that baseload generator to start its auxiliaries and return to service;
- Baseload coal-fired generators that are fitted with trip to house load (TTHL) equipment. Plant fitted with TTHL detects a system disturbance (high or load frequency, low voltage or pole slip), disconnects the generator from the system and unloads the boiler and steam turbine to supply house load (the auxiliaries associated with a unit that must operate for it to be able to run) directly from its own generator. TTHL almost always utilises turbine by-pass equipment and a distributed control system (DCS) to achieve the required controlled load rejection.

Each of these providers of a black start service faces significant difficulties in a system shutdown.

Often a black start provider would be filling two roles: firstly as a generator with multiple recently tripped generating units and secondly as a black start provider. This will likely create conflicting priorities for the provider:

1. The provider must ensure that its generating units have safely shut down and have been secured.
2. The provider may be dealing with damage to one or more of its own generating units, sustained during the system shutdown. For example, a turbine/generator may have run down without bearing oil or the provider may be dealing with a major fire at the site.
3. The provider most likely will only have limited staff on site at the time of the system shutdown. Several power stations comprise four units (and up to eight at Hazelwood) and a simultaneous shutdown of all in service units would require a substantial involvement of operating staff on site to secure the tripped units. To also manage the start and run up of the black start source with its associated switching operations would require use of scarce staff resources.
4. The black start gas turbine may be some distance from the main plant. In most cases, black start plant can be started remotely from the main generating plant control room but it would usually be prudent to have staff present onsite to ensure that the black start plant starts safely and operates properly. The requirement to have staff onsite would potentially tie up staff and vehicle resources that may be needed on the main generating plant.
5. If the generating plant is trip to house load (TTHL) capable and has survived the system shutdown, then the provider would also need to ensure that this plant is stabilised and returned to a secure operating position in readiness for reconnection to the network and subsequent loading. Boiler firing would need to be adjusted and the turbine bypass system activated. It is likely that a number of safety valves would have operated, particularly around the reheater, and demineralised make-up water would be required to replenish the feedwater system.
6. Communications between the system operator and black start provider are likely to be difficult to establish and sketchy in detail. In the immediate confusion of multiple tripped units, lights out in the control room and turbine hall, control screens flickering to life again as emergency power supplies are established and phone calls coming in requesting information, it is likely that generator staff will take some time to establish the correct course of action.

   It is also quite possible that the system operator may not be fully on top of what has just taken place or the true extent of the power system failure. Further, it is most likely that the system operator will also have many conflicting priorities to deal with. Hence, it is quite plausible that a black start provider may not receive a clear direction from the system operator until a significant time has elapsed.

All the above conflicting priorities are likely to delay and/or compromise the effectiveness of the black start source to get local generation up and running again. This could be a serious situation if this were the only available contracted black start source in the sub-network.

Challenges for generators relying on SRAS providers

The last total system shutdown in NSW occurred in 1964 during a severe winter electrical storm. That shutdown occurred just after midnight and the system was fully restored to service by 7 am with most customers unaware that a major power failure had occurred.

The network and generating system was very different in 1964. The demand at the time of the shutdown was around 1,200 MW compared to a typical midnight winter demand of 9,000 MW these days. The largest coal-fired generating units (Vales Point units 1 and 2) were 200 MW with most other generators being around 30 to 60 MW in capacity.

A number of factors contributed to the fast return to service of the system back in 1964:

- The network was considerably smaller and was lightly loaded at the time of the shutdown;
- The small generators had relatively large steam drums which had steam capacity that allowed operators time to disconnect the generator from the system, run up the turbine on reserve steam and energise the generator to supply the unit auxiliaries. Because the boilers did not have a reheater, mills could be flashed off and the unit resynchronised to the system and loaded quickly;
- Operating staff at the time were well experienced with this type of operation and regularly took units off and on line to manage system demand; and
- Several towns and load centres had local generation available which facilitated supply restoration in some areas within an hour of the system shutdown.

It would be a very different situation for generators today if there were a total system shutdown. Factors that would render a system return to service both difficult and challenging are discussed below.

Large base load coal-fired generators

A substantial proportion of demand is supplied from base load, coal-fired generators installed after 1970. These are typically in the range 350 MW to 660 MW units and are inherently more difficult to start than generators installed in the 1940's and 1950's.

Complex plant design and operation

All coal-fired generators now are significantly more complex and operate with much finer tolerances with respect to clearances, steam conditions and metal temperatures. With the exception of Hazelwood, all boilers now have a reheater stage which reheats steam before it passes through the IP and LP turbines. The reheater requires very careful heating during the early stages of a unit return to service and most boilers cannot be fired with coal until after the unit is run up and synchronised unless they are fitted with a turbine by-pass system. These limitations mean that it takes much longer to return a unit to service, unless they are already in a very hot state following a unit trip.

Generators rely on external supplies to restart:

All coal-fired generators require electrical supplies to start their auxiliary plant (e.g. fans, pumps, mills) to enable the generator to be started up. Typically, a generator requires around 4% of its rated output to get started and this is normally supplied from the system or from an adjacent generator. In a total system shutdown, these supplies would need to come from a black start source unless the unit were fitted with trip to house load (TTHL) equipment and provided that unit successfully tripped to house load.

Complex shutdown and restart process:

Any delay in getting supplies to the unit auxiliaries will impact on the likelihood that the unit returns to service successfully and trouble-free.

Immediately following a unit trip, the operating staff must ensure that the unit is disconnected from the network, the turbine runs down safely, the boiler fire is out and the unit is then placed into a secure state to ensure that damage is minimised. This process takes time and will be seriously impaired if key auxiliary supplies are not immediately available. All stations have emergency diesel generators on site to provide these supplies and to recharge station batteries used to run emergency dc pumps and fans. If the diesel generator fails to start, then operating staff would be required to manually operate drain valves and other equipment to prevent further serious damage. It should be noted that the diesel generator can only supply the most critical of auxiliaries and cannot be used to restart a unit.

Once the unit is in a secure state, operating staff would assess the likelihood that supplies would be restored quickly either from the system or a black start source. If there were to be any delay, the operator would take steps to minimise steam temperature and pressure loss by controlling drainage and closing in boiler air and gas pass dampers. Any delays beyond a couple of hours would start to impact critical metal temperatures in the turbine and reduce the chance of a normal hot restart.

A hot restart from a tripped condition is the easiest restart provided boiler firing is established quickly. If, however, the restart is delayed then problems start to emerge with matching steam and metal temperatures in the turbine and steam mains and after six to eight hours delay, the restart becomes a warm restart which is operationally far more challenging due to different metal cooling rates between the turbine shaft and casings. While this can be managed, it means a much slower return to service to ensure proper heating of the different turbine parts.

In a situation where a generator is relying on electrical supplies from a black start source, any delay or interruption to supplies has a compounding impact on the time it would take to return the unit to service.

Remote location of generators:

Generators are usually located close to fuel sources and secure water supplies which means most are remote from the main load centres of Sydney, Newcastle, Wollongong, Melbourne, Geelong, Brisbane and Gladstone, all of which depend heavily on base load generation. In a system restart situation where the main load centres are distant from the generators, this creates very challenging conditions for matching generator output with loads resulting in a higher than normal risk of generator trips.

Challenges for the transmission system

Establishing a restart plan

The transmission operator is unlikely to know the cause of the shutdown, nor what is serviceable on the network. Therefore any restoration plan must be as flexible and resilient as possible. Broad plans can be written into documents, but these largely assume that the network is 100% available (which is clearly absurd, since if it was it wouldn't have shut down in the first place). Hence operations staff need to be fully versed in the *principles* of restoration, so that plans can be adapted as required to manage the actual circumstances.

Assuming the whole network to be black (i.e. no surviving power islands) the first task is to establish the status of the black start sources. If more than one is available, then plans should be developed to work with as many as possible to ensure restoration timeframes are minimised. However, where the source is a gas turbine used to start a larger coal unit, it is unlikely that any transmission network will be required for at least 90 minutes whilst the start-up sequence is executed. Hydro generation will usually be available within 15 minutes of a black out so initial effort would be focused in this area. If an adjacent electrical sub-network was still functional then this would provide a useful source which could be used immediately.

Whilst the ultimate objective is the restoration of all load, in the early stages the plan is:

1. To restore auxiliary supplies to all power stations, and
2. As far as possible, prioritise the restoration of critical loads.

This is done by establishing a "skeletal" network between key substations, of sufficient capacity to supply auxiliary load but with enough duplication to withstand a single contingency event (this is not possible initially, but is incorporated as soon as it can be.)

Enacting the plan

Before any part of the network can be reconnected, it must first be fully disconnected to ensure that only the intended equipment is re-energised. This can usually be achieved by SCADA but requires a very diligent, thorough approach (a large substation may have in excess of 30 circuit breakers, all of which must be opened).

The transmission network is designed to operate with power measured in GW. However, the first load to be established will only be a matter of a few MW, which gives rise to a number of technical issues. The first circuit to be energised will experience very high volts, which the restart source must be able to regulate (absorb MVAr) if damage to insulation is to be avoided. Once the first circuit is established, then the distributor will pick up a small amount of load at the receiving end which, if done correctly, will pull the voltage down to a more nominal level. Thereafter the distribution substations along the restoration path must also be made ready, by opening of all circuit breakers (now possibly in the region of 50-60 circuit breakers at larger distribution substations). Once this is done, a selected few distribution feeders are re-energised to put on the amount of load requested. Too much load will probably cause the black start source to trip. Too little load and the voltage will remain too high to energise the next line.

Using this technique of restoring a line then picking up a small amount of load enables the operator to progressively restore the skeletal network. This can be done up to the point of the restart source reaching its full capacity. Any power station that receives supplies commences its own restart process. Once available, it is used to restore more demand and extend the network.

Parallel paths are established as soon as possible to allow for possible repeat contingent events (for example, if the shutdown was caused by a bushfire it is quite probable that the bushfire is still burning and could cause further tripping).

If multiple restart sources were available, the next stage is to consider how and when to join the networks together. This should not be done too early, since the networks are very delicate during the early stages and there is a risk that a problem with one could collapse the other.

After a few hours, more large generators should become available, allowing more load to be restored and more network to be energised.

A particular problem is encountered when restoring supplies into Sydney CBD, which is via a 330kV underground cable network. The high voltage experienced when energising an overhead transmission line is an order of magnitude worse when energising a cable. Unless the network is already fairly robust with significant load already restored, energising a 330kV cable will probably result in extremely high volts and corresponding damage to plant.

Potential problems

During the early stages of restart, the network is very fragile and the slightest unplanned event can see things unravelled. If an operator failed to fully disconnect a substation before re-energising it, then the probability is that a much larger chunk of load will be connected than the system can withstand and so it will collapse the whole network.

Reconnecting stabilising load in the required block sizes is very difficult. Although the loading on a particular feeder before the shutdown might be known, there is no guarantee that this will be the load picked up on restoration. (Thermostats reset, systems restart themselves as soon as power is restored so a significant increase can be anticipated).

Multiple-circuit tripping and subsequent network collapse makes fault diagnosis virtually impossible. Circuits that have tripped may not have faults on them, whereas circuits that did not trip may have faults. The operator will have to make educated guesses based on limited information as to which circuits are most likely to be suitable for use for the restart process. Closing onto a fault could easily sink the whole system during the early phase of restoration.

During the restoration it is quite probable that the cause of the shutdown is still active. If, for example, bushfires caused the initial shutdown, it is quite probable that they will still be active whilst the restoration is being attempted, exposing the process to further risk.

Communications will be seriously disrupted, with the public telephone network likely to become congested and unusable. AEMO does not have a dedicated telephone connection to the TNSPs so a coordinated restoration strategy could be seriously hampered.

Black start as insurance

Given the risk of a major black out it is appropriate to view the provision of SRAS services as a form of insurance to mitigate the consequences of this event. Just like house insurance it is something that is important to have even though it is expected and hoped that this insurance will never be utilised. The key question is determining the optimal level of insurance – the events covered, the size of the excess compared to the premium.

It would be generally viewed as foolhardy to make a modest saving in the cost of the premiums for a material reduction in the effectiveness of household insurance cover. The concern with the current situation with SRAS provision in the NEM is that this may be the case. We would also note that the recent 50% reduction in SRAS costs equated to a cost reduction of less than $2 per customer per year.

Issues with current arrangements

There is a range of concerns with the current SRS and its implementation by AEMO. These include:

- The reliability of black start providers and the generators that have to rely on supplies provided by black start sources and the implications of this reliability.
- The expected restoration times given the current black start providers and the implications of these.
- The form of the current standard and issues that this creates.
- The technical, and somewhat arbitrary, form of the current standard (as opposed to an approach that reflected the economic trade-off being made).
- AEMO's possible reliance on its powers of direction to restore the power system
- Problems associated with validation of AEMO's compliance with the standard and black start providers capabilities

Reliability of black start providers and generators

Reliability of black start providers

Each of the available types of black start sources have been contracted at various times by AEMO to meet its obligation to procure sufficient SRAS for each electrical sub-network.

As part of a SRAS contract, the black start provider is required to meet specific reliability standards made up of both availability and start-up performance measures.

Before entering into a SRAS contract, the provider must demonstrate that the black start plant, including the connecting network and the receiving generating plant, is capable of providing the service. The provider must carry out a full black start test which includes:

- Starting the black start generating plant without external supplies;
- Energising a dead busbar;
- Holding export load at zero for 30 minutes;
- Demonstrating that the plant is capable of controlling voltage and frequency; and
- Proving that the plant is capable of meeting specified timeframes.

The most recent SRAS Guidelines specify that these measures must now be demonstrated at the Delivery Point which is defined as the transmission network connection point to which a generating unit forming part of SRAS equipment is assigned in the NEM. Hence, for a small embedded open cycle gas turbine supplying the auxiliaries of a base-load generator, the SRAS provider must demonstrate capability by running up and loading the base-load generator, since it is the asset connected at the Delivery Point. For this class of provider, AEMO now assesses the combined performance and timeline targets of the embedded generator and the market facing generator when deciding between one SRAS tender and another.

Under the SRAS agreement, the black start provider must also carry out annual tests to confirm ongoing compliance to the contracted performance measures.

There are however significant differences between annual testing and actual black start conditions.

Under test conditions, the black start provider is required to submit a test procedure, which is prepared well ahead of time and approved by AEMO. Significant planning goes into preparing for a test including ensuring that the primary restart equipment has been checked, test run, maintained, tuned up and cleaned. Ancillary plant such as air compressors, diesel generators are test run beforehand. An annual test usually requires special switching to isolate the black start path from the rest of the system and this can often take several days to prepare beforehand such as isolating switchboard buses from others to ensure the test plant can be made truly "black". A provider might dedicate one shift of operators to manage the test procedure and schedule the test to occur when that shift is in attendance. Because there is live plant around the test path, the switching and isolations are complex and require careful planning to ensure that the test proceeds smoothly on the day.

This level of rigor would apply to annual tests carried out by each of the classes of SRAS provider, albeit to varying degrees. Because the black start plant under test has to be isolated from the rest of the plant, this creates an unusual plant configuration which is both unfamiliar and atypical to what would be there in a real system black condition. While it is acknowledged that it would be difficult to carry out a test any other way, the planning and the setup for a test is focused on achieving a successful result. This could give the impression that a true black start will always proceed with the same level of military precision and achieve the same reliability.

Under actual black start conditions, the situation would be very different.

The challenges that a black start provider would face in a system shutdown have already been discussed. Putting aside the immediate confusion and conflicting priorities that the black start provider would face, this section looks at some of the reliability issues that the black start plant would almost certainly encounter in an actual system shutdown:

A system black condition almost always comes without warning. In a system shutdown, all external supplies are lost and each generating unit, excepting any with TTHL, falls back to requiring emergency supplies, usually batteries in the first place, to enable the plant to shutdown safely. Batteries run key emergency auxiliaries such as bearing oil pumps, cooling fans and pumps, hydraulic oil pumps, control systems and emergency lighting. Station batteries have a finite life and must be backed up quickly by emergency diesel generators before they become exhausted.

Additionally, each class of SRAS provider also has its own reliability challenges.

Market facing open cycle gas turbines or hydro plant used for SRAS

Usually this plant would be remotely started to enable the plant to be dispatched when AEMO makes a call. However, the plant may not be staffed at the time of the system shutdown or, if it was running, may have sustained damage as a result of the trip. With remotely operated plant, it would be usual for the SRAS provider to dispatch staff to check first that the plant was in a fit state to operate and then check that auxiliaries required for the start were running correctly. Further, in a system black condition, remote starting may not be possible if the start/stop commands rely on the internet or other telecommunication media.

In most cases, a diesel generator or compressor would be a key component to starting this class of plant. If the batteries have failed to provide sufficient energy or have become exhausted due to multiple start attempts, it may be necessary, for example, for an operator to manually crank start a diesel air compressor to get a large diesel engine started.

Embedded open cycle gas turbine with base-load generator used for SRAS

Again, this plant would usually be remotely started but operating staff would first need to confirm that the network path was available to transfer energy to the larger generator auxiliaries. Under most circumstances this would be much easier than for an annual test since all generating units would already be in a shutdown state. However, staff would still need to be dispatched to the site of the black start plant to check that plant was safe to start and that the required auxiliaries successfully operated.

Because of the nature of the plant, it is likely that this plant would have spent large time periods on standby, only being operated infrequently for testing purposes. This could potentially impact its reliability, particularly on start up. Issues such as starting interlocks not satisfied, failure to fire or loss of flame can occur during a run up. These sorts of starting issues can significantly delay a start or even render the plant unavailable.

Once supplies are available to the base-load generator switchboards, then operating staff would need to prioritise the starting order of the tripped generating units taking into account any damage each may have been sustained during the shutdown and the likelihood of a smooth return to service. As has been discussed before, coal fired generators are inherently difficult to restart, particularly if there have been delays in getting supplies to the unit auxiliary switchboards. Delays of more than one or two hours to a hot unit would start to significantly impact the time it would take to run up a coal fired generator and export to the network.

Trip to house load used for SRAS

With several power stations in the NEM now past mid-life, a number have upgraded to a distributed control system (DCS) which allows much finer control of the steam and air/gas circuits and significant improvements to the control of plant disturbances than was possible with the older control systems. When coupled with a turbine by-pass system the unit can be made to trip to house load (TTHL) in the event of a severe system disturbance. A tripping relay disconnects the generating unit which may be at or near full load, unloading to almost zero load and continuing to operate for lengthy time periods with the generator supplying electrical energy to its own unit auxiliaries. The DCS unloads the boiler and turbine in a controlled manner such that drum level is maintained whilst still being able to keep two or three mills in service. Depending on the capacity of the LP turbine by-pass system, the reheater safety valves may lift to release pressure before the IP turbine but even this can be carried out in a controlled manner. The stabilised unit can then be resynchronised to the system and loaded quickly using the mills already in service.

Simulated and actual load rejection tests using TTHL systems have demonstrated good reliability with some rejection tests being successfully carried out from full load. A number of power stations in the NEM have made TTHL available at times for SRAS including Loy Yang A, Callide B, Stanwell and Northern power stations.

Relays installed on each of the generating units are set to detect high system frequency (around 52 Hz) or low system frequency (around 47 Hz), low system voltage or pole slip and these will trip the respective units to house load after a short time delay.

When assessing the potential reliability of the TTHL schemes in an actual black system condition it is important to understand that physical testing of these schemes is carried out under normal stable system conditions, i.e. frequency of 50 Hz and normal voltage. While low frequency signals may be injected into the tripping relays to simulate a low frequency, the base-load plant under test is operating in a normal stable network environment at the time the test.

However, in a collapsing system, either one involving voltage collapse or severe under frequency or both, the situation would be very different and present significant challenges for the DCS.

Several factors work against a generating unit in a collapsing system, as the following sequence shows:

1. As frequency drops, the generator governor responds immediately by opening the turbine throttle valves to admit more steam, thereby increasing generator output to compensate for lost generation elsewhere. This sudden demand for steam can be quite severe causing significant control issues in the boiler; both with drum level and combustion stability, as the DCS works to restore equilibrium. The DCS manages this by increasing feedwater flow and fuel into the boiler;
2. As frequency continues to fall to say 48.5 Hz, major auxiliaries such as air and gas fans and electric feed pumps slow down forcing the DCS to work harder to restore balance;
3. If frequency continues to fall to 47 Hz the air and gas fans may be hitting capacity limits which under stable conditions would be manageable but much less certain in a collapsing frequency situation. Up to this point, the DCS is working hard to increase generator output to maximum, whilst at the same time keeping drum level and the furnace stable;
4. And then at 47 Hz the TTHL relays operate to disconnect the generating unit from the system. The DCS has to work now in the opposite direction to unload the generator from near full load to almost zero load while the turbine by-pass system opens to direct surplus steam around each of the turbine stages to enable two or three mills to remain in service while the generator supplies its own unit auxiliaries.

This is a very challenging sequence for a DCS and it is very likely that it would be unable to control drum level and/or combustion stability during this major disturbance which could ultimately lead to the unit tripping.

Voltage collapse would undoubtedly follow a similar path, probably more severe and much less certain.

Overseas experience with load rejection performance, as cited by M Adibi [7], the IEA [3] and the U.S. Canada Power System Outage Task Force [2], shows the following success rates for load rejections during major system disturbances:

Network	Success rate of individual units (%)
Germany	50%
France	20% to 80% (nuclear)
Ontario Power (14 August 2003)	36% (nuclear)
Italy (28 September 2003)	26% (thermal)
Sweden/Denmark (23 September 2003)	40% (thermal) but all failed during final voltage collapse

Nuclear power station data is included since these plants experience similar issues in a collapsing frequency with slowing feedwater pumps causing potential steam generator water level control problems.

From the above international data, a unit tripping to house load coupled with a full load rejection has a less than 50% chance of surviving a system collapse and the chance may be much less, as was experienced in Italy and Sweden/Denmark.

For example, with TTHL fitted and active on all units at a four unit power station, the chance of at least one unit surviving out of the four, assuming a 50% probability, would be 94% but if the survival rate were only 20% probability, then the chance of at least one unit surviving would fall to 59%. A worse scenario again would be if any number of the units at that station had already tripped before being able to trip to house load having already become part of the cause of the system collapse.

It should be noted that in an over-frequency event, the chance of survival of a TTHL unit would be higher. As frequency increases the governor automatically closes in the turbine throttle valves to reduce generator output while the DCS works to control drum level and reduce fuel to the boiler. By the time the TTHL relays operate at around 52 Hz, most of the load would have already been backed off making for an easier transition to tripping to house load. However, because of the speed that an under-frequency event can flip over to an over-frequency event, this could still be potentially very challenging for a DCS.

In summary,

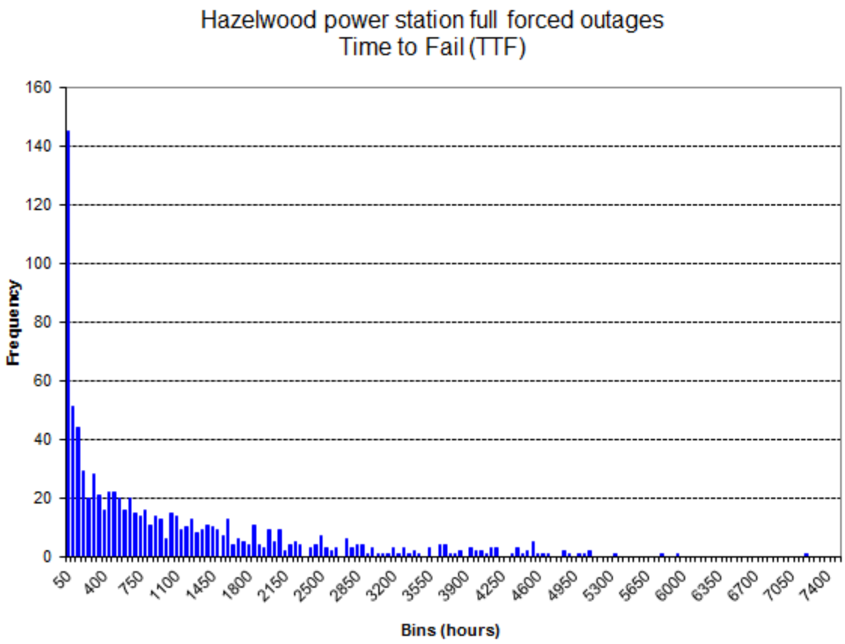
- All modes of SRAS would face significant challenges to meet the required level of service that is mandated in the current SRS.
- The least vulnerable SRAS mode, in our view, is a black start source supplied from hydro plant. However, most hydro plant are quite remote from the main load centres and power stations where energy would be required quickly.
- Black start energy supplied from an embedded gas turbine coupled with a base load coal fired generator is unlikely to be able to supply significant energy to the market within 4 hours due to a chain of reliability challenges that providers of this service face – from starting the gas turbine to lighting oil torches in the boiler and firing mills.
- Trip to house load schemes offer the best chance of supplying sizable quantities of energy to the market quickly. However, in our view, the reliability of these schemes in a state of system collapse is presently untested and hence is being overstated and over-relied on.

[7] IRD 2004, Power System Restoration, Mike Adibi, IRD Corporation

Reliability of generators restarting

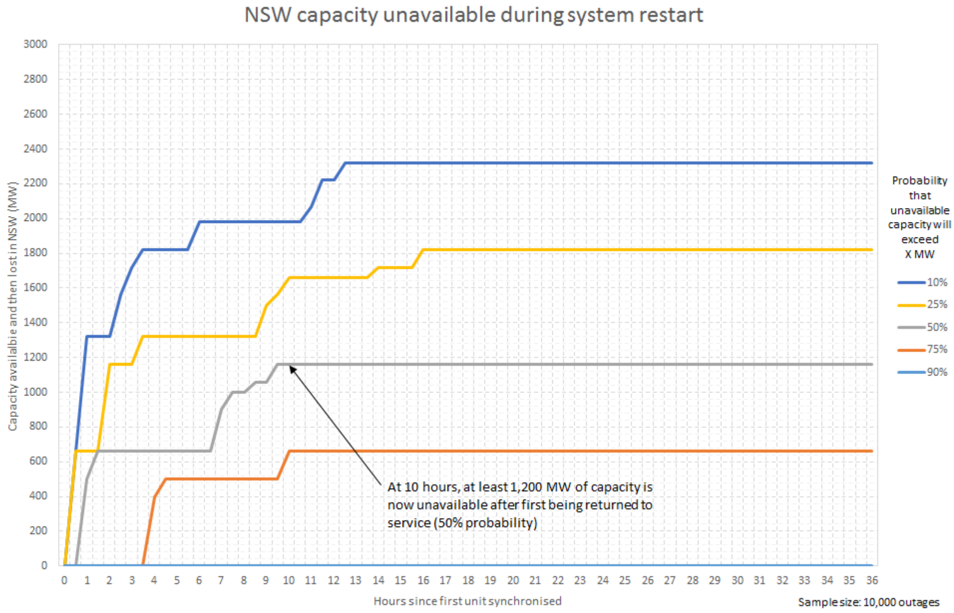
There is a further issue that needs to be explored: once base-load generators get back on line, there is an increased risk of failures and trips in the first hours of rebuilding a system from a black condition.

To examine this, outage data was analysed from around 80 generating units in the NEM over a period of more than ten years to identify each time a unit was returned to service and then forced out of service again, either by unit trip or other full forced outage. A distribution of times-to-fail (TTF) was created for each base-load power station to enable the failure characteristics to be calculated. The following chart shows the distribution derived for Hazelwood power station.



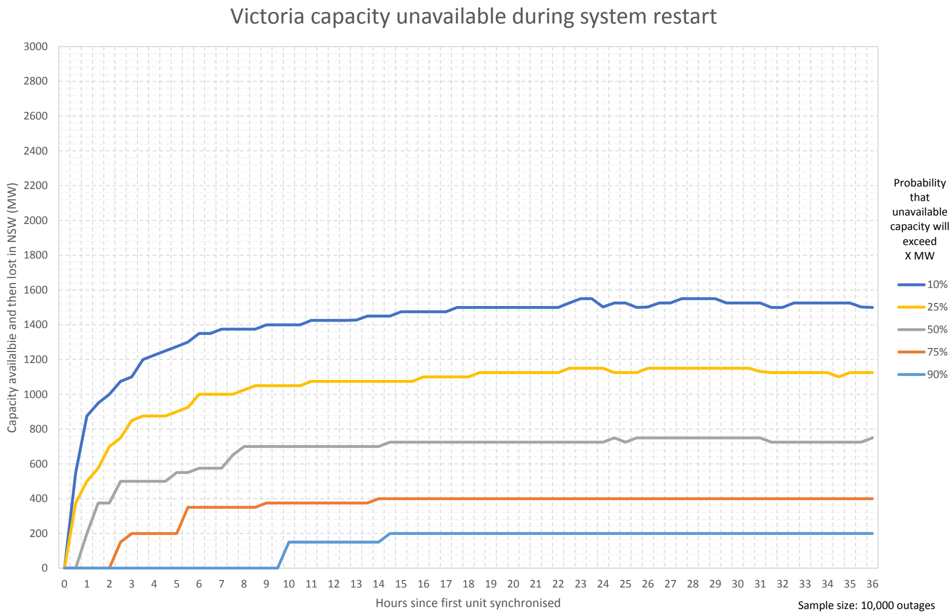
The distribution is a typical Weibull component failure distribution exhibiting a beta (β) of around 0.5 and indicating that forced failures at power stations fit an "infant mortality" profile. Put simply, a generating unit is more likely to fail in the first hours or days of coming back into service than after a week or a month of continuous operation. All base-load power stations yielded similar distributions. By determining the Weibull parameters for each base-load power station, it was then possible to model generator failures in the first 36 hours following a system black condition.

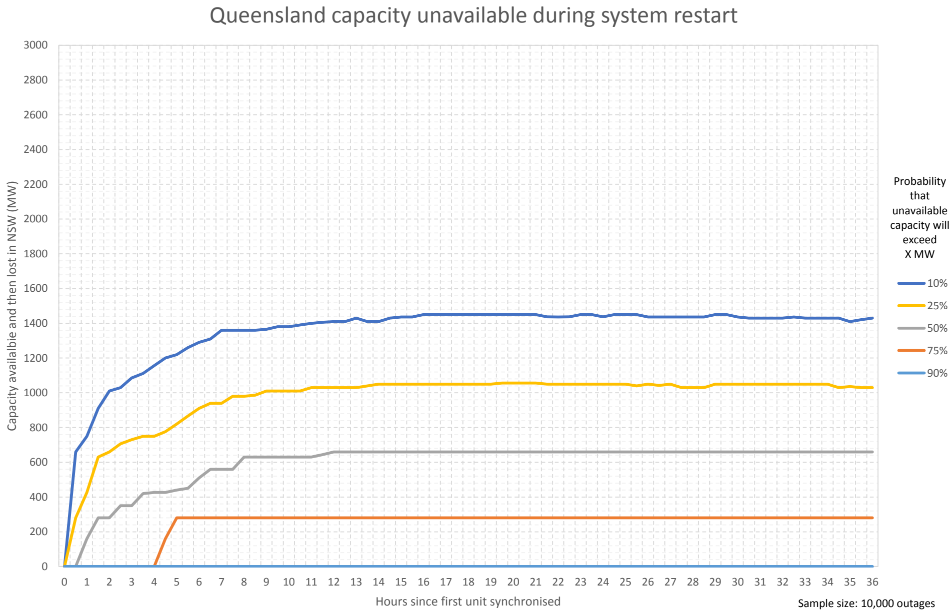
The following graph shows the modelled volume of generation in NSW that successfully returned to service but then tripped or failed, expressed in terms of likelihood.



The graph shows by the hour the probability that generating capacity trips out after first being returned to service. For example, at the 10 hour mark there is a 50% probability that at least 1,200 MW of capacity that had been returned to service will no longer be running.

The following graphs show similar probability distributions for Victoria and Queensland:





Analysis of both Victoria and Queensland showed that potentially less volume would be lost in each region following a black system restart than in NSW. At the 10 hour mark, for example, there is a 50% probability that the regions would lose a minimum of 600 MW capacity each.

Implications of reduction in number of black start sources

As detailed above there are a range of reliability issues for both black start sources and generators restarting in the event of a wide spread black out. These are summarised below:

- There is a big difference between a test or simulation and an actual system black condition.
- When external supplies are lost, power stations rely heavily on batteries and emergency supplies to protect hot spinning machines. These can become depleted quickly or fail to operate altogether.
- During a rundown without external supplies, there is a greater potential for damage to the plant because there is less redundancy built into the plant in this mode.
- Black start plant is dependent at times on emergency auxiliary plant that may only be operated infrequently, for example, a back-up diesel air compressor. If the emergency back-up fails when needed, there is no black start service.
- A gas turbine dedicated solely to black start may only be operated infrequently. Starting interlocks, limit switches, fail to fire, loss of flame can all prevent or delay a successful start.
- To successfully run up a base load coal fired generator using an embedded black start source, a long sequence of operations all need to work correctly. Any complications requiring the sequence to be restarted will cause significant delays and reduce the chance of a successful hot restart of the plant.
- In a collapsing system situation, it is likely that several TTHL units will fail to ride out the disturbance.
- Once base-load generators come on line, there is a higher risk of trip or failure than during normal service. Unstable frequency and voltage in the local network will increase this risk.

In light of these risks and the historical performance of black start sources internationally it is clear that the probability of success of black start sources and the generators relying on them to be able to supply load in an acceptable time from is less than 100%. As a result limiting the number of black start sources in a sub-region creates a material risk of failure to be able to restore supply to customers in that region in a reasonable time frame.

The obvious way to mitigate the risk of both black start providers and the generators relying on them is to increase the number of black start sources that are attempting to operate and as a result increase the probability of success to an acceptable level.

Reliability of network restoration

Even if all black start providers and generators perform as expected, this still leaves considerable risk in the restoration of the network. Primarily this occurs at the transmission levels and to a lesser extent at the distribution level as load is returned to the system.

Consideration of issues at the network level is best thought of in terms of the restoration process that is required and the timing which specific elements are reenergised and reloaded. The following sections outline a number of expected restoration paths for NSW. We would note that the timing presented in these sections assumes no further generation trips or network failures.

Expected restoration times

The following times are based on information provided by generators and distributors, who have then participated in annual simulation exercises for NSW coordinated by TransGrid. The results of these exercises have then been used to refine the black start plans and estimate the restoration times. This is the most accurate method of deriving time estimates short of actually conducting a live exercise.

Restoration initiated from Snowy

As already discussed, the restoration plan involves establishing a skeletal network and incrementally applying load to control the voltage.

The time taken to have generation units in service and capable of supplying load is a function of two inputs. Firstly, the time taken to restore supply to auxiliaries to allow a return to service to commence and, secondly, the time then taken for the return to service (synchronised and ready to load).

A range of typical return to service times are: [8]

Station	Hot restart (hours)
Bayswater	3.0 to 5.0
Liddell	4.0 to 6.0
Mt Piper	3.0 to 5.0
Vales Point	3.5 to 5.5
Eraring	3.0 to 5.0
Hazelwood	2.0 to 4.0
Loy Yang A	2.5 to 4.5
Loy Yang B	2.0 to 4.0
Yallourn W	3.0 to 5.0
Callide B	2.5 to 4.5
Callide C	3.0 to 5.0
Gladstone	2.5 to 4.5
Kogan Creek	2.5 to 3.5
Millmerran	4.5 to 6.5
Stanwell	3.0 to 5.0
Tarong	2.0 to 4.0

The return to service time increases as the time to restore supply increases. This is caused by the units cooling and therefore requiring longer to return to service. For example a delay of 2 hours in making supplies available to auxiliaries could add about 3 hours to the best expected time to return a unit to service.

<u>Time to restore auxiliaries to Power Station and return first unit to service</u>

Station	**Time to restore auxiliaries (mins)**	**Time to return to service (mins)[1]**	**Total time to synchronise to network (hrs)[2]**
Mount Piper	95	240	5.6
Vales Point	160	450	10.2
Eraring	170	420	9.8
Bayswater	180	420	10.0
Liddell	180	480	11.0

[1]This is the time to return to service *once auxiliary supplies become available*.

[2]This is the time taken from shutdown to reconnect to the network and begin taking load. Note that the run-up to full load could still take several hours.

[8] Based on review of NEM data with return to services with unusual delays excluded

Supplies to Other Key Stakeholders

Substation	Initial Energisation	Time to 100MW	Time to 200MW
Canberra	20 mins	30 mins	60 mins
Sydney South	80 mins	100 mins	155 mins[1]
Sydney West	90 mins	155 mins	180 mins[2]
Sydney North	140 mins	150 mins	180 mins[2]

[1] Supplies from Sydney South would be used to form a limited connection through to the Sydney CBD through the Ausgrid network, with the intention of picking up emergency load where possible. At this stage it would equate to approximately 100 MW of CBD load. Further load restoration would not be possible until 4-5 large generators were synchronised and the cable network could be energised, which would be anticipated at around the 5 hour mark.

[2] Note that this assumes that there is sufficient generation at Snowy available.

Supplies to Tomago smelter

Tomago smelter is the largest and one of the most sensitive loads in NSW. Auxiliary supplies to Tomago are anticipated around the 185 minute mark. It should be possible to pick up load to a maximum of 230 MW, provided it is done in an incremental manner. No further Tomago load can be restored until at least 2 large generators have synchronised (or 1 generator + 4 Colongra GT units).

Limitations on Snowy restoration

If Snowy is the only restart source, it will not be possible to restore more than 2,000 MW of load, with only 1,700 MW available north of Canberra (voltage stability issues).

Although not currently a problem, Snowy can also be energy-constrained depending on the availability of water, under which circumstances restoration of customer supplies is reduced and the focus put on getting supplies to power station auxiliaries.

A load of 2,000 MW would probably be reached at around the 4-5 hour mark, by which time units at other power stations should be ready to synchronise.

Restoration initiated from Bogong / McKay Creek hydro stations

The latest restart sources for southern NSW that have been procured by AEMO are located approximately 100km south of the NSW border at Bogong and McKay hydro stations (part of the Kiewa Hydro Electric Scheme). On the basis of having this source, AEMO did not elect to contract for a restart service with Snowy Hydro. Therefore black start plans have recently had to be modified to allow for the time taken for a supply to be brought up from Kiewa (Mt Beauty) to Upper or Lower Tumut substation. The same principles apply here as previously discussed, with a line being energised, then a small load applied before the next line can be energised. Studies indicate that this will take in excess of one hour. Therefore all of the times quoted for a restoration initiated by Snowy need to be increased by one and a half hours if restoration is initiated from Bogong/MacKay Creek.

Restoration initiated from Eraring GT

This plan requires Eraring power station to initiate a start of one unit using their on-site gas turbine.

Time taken to start one unit is approximately 210 minutes based on the most optimistic return to service time. This will then be used to supply a small local load, then energise a small network in its immediate vicinity. This will include auxiliary supplies to Tomago, Vales Point and Liddell / Bayswater.

Time to restore auxiliaries to power station and return first unit to service

Station	Time to restore auxiliaries (mins)	Time to return to service (mins)	Total time to be able to supply load (hrs)
Eraring (first unit)	30	180	3.5
Eraring (remaining units)	210	420	10.5
Vales Point	220	450	11.2
Colongra	230	30	4.3
Bayswater	240	420	11.0
Liddell	240	480	12.0

Supplies to Tomago

Auxiliary supplies should be available to Tomago at around 230 minutes (3.8 hours). However, it will not be possible to energise a pot line until at least one extra unit (or the 4 Colongra GTs) are available. This would be around 260 minutes (4.3 hours) after the shutdown. At this point it should be possible to energise a single pot line.

Restoration initiated from multiple sources

If concurrent restarts are initiated from multiple sources, then the above times will be significantly reduced at certain stages of the restoration plan. Benefits arise as, for example, the path from Snowy arrives at Eraring at the same time as the unit is ready to synchronise. It can be brought on to a fairly solid network and allowed to run up at its preferred rate, avoiding the delicate and frequently precarious problems associated with initial loading. This significantly increases the probability of a successful start.

These benefits multiply if more stations are capable of self-starting.

If for some reason it is not possible to build the skeletal network (due to the damage that caused the shutdown in the first place), then having more sources available means that there is a better chance of safely restarting, say, the north part of the network, rather than relying on a connection that is not available.

The estimates of restoration times raise questions about whether the current SRAS arrangements will achieve the requirements of the SRS. This is particularly the case if the risks of failure are taken into account – both at the generation and transmission level.

Implications of expected restoration times

The issues raised above suggest that actual restoration times will be significantly longer than expected. This is likely to create material impacts on customers and the wider economy. The following sections outline these impacts.

Submission to AEMC Reliability Panel in response to:

"Review of the System Restart Standard"

Social impacts

Whilst the impact of system shutdowns around the world is frequently quantified in terms of dollars, this in itself does not include the complete social cost. This is a list of the sorts of issues that can be anticipated:

Initial shutdown to 1 hour

- The mobile phone network becomes congested / exhausted.
- Traffic lights stop working.
- Industry stops.
- High-rise buildings will have people trapped in lifts.
- Underground trains will have people trapped in a hot / stuffy environment.
- Even though media radio transmitters have back-up supplies, most people will not have any means of receiving information broadcasts (except car radio).

1 to 3 hours

- Total gridlock in all larger towns. Emergency response vehicles trapped.
- Backup generators (e.g. at hospitals) begin exhausting their fuel supply, cannot refuel.
- General level of civil panic rises due to lack of public information.

3 to 12 hours

- Water treatment / sewage problems as pondage overflows & sewage is not pumped away.
- Fresh water becomes contaminated.
- Breakdown in law & order.

Impact on aluminium smelters

Aluminium smelters are major users of electricity. For example Tomago Aluminium consumes in excess of 8,000 GWh per annum. This is typical of other large smelters in Australia. They are also major creators of both direct and indirect employment. A typical contribution would be in excess of 1,500 jobs for each smelter.

Whilst a 1 hour interruption is inconvenient and represents a loss of production, matters start to become serious at around the 2 hour mark. By the 3 hour mark it is anticipated that some pots would begin freezing. By 4 hours the situation would be irredeemable, resulting in all pots being frozen.

Getting auxiliary supplies to the smelters is important since this means they can begin reconfiguring the operation in anticipation of a lower supply. However, until supplies in the order of 200 MW are available, the rapid deterioration described above will continue. Even 200 MW will not be sufficient to completely arrest the decline, but it will slow the process.

Any plan that does not restore full supply to the smelter within 3 to 4 hours is likely to result in complete freeze of the pot lines. The costs of remediating the smelter after such an event approach replacement cost.

Noting the above times for both Snowy and Eraring initiated restarts, it is clear that Tomago will not receive supplies within the required timeframe.

Without access to similar simulation information for Victoria, it is only possible to make some broad comments about the Alcoa smelter at Portland:

- The distance from Loy Yang to Portland is similar to the distance between Snowy and Tomago. However, Loy Yang is not a hydro station so will not be able to energise much of the network before further generation is required, which will be restarting from a tripped condition (taking around 90 minutes based on available data) after which a restoration path could be established.
- The distance from Kiewa to Portland is even further. The Kiewa scheme is considerably smaller than the Snowy scheme so would struggle to energise much of the network.

Therefore it is not expected that Portland would receive supplies in the timeframe required to save the plant.

Currently aluminium smelting in Australia is facing difficulties due the low aluminium price in spite of the reduction in the value of the Australian dollar. Given the reduced margins that Australian smelters expect to earn in the future, it is highly unlikely that the current owners or any other party would reinvest in repairing the smelter after a significant black out. This would imply that a major black out would be likely to lead to the permanent shut down of the affected smelters.

The shut down of the smelters would result in the loss of thousands of jobs and the associated economic value. For example the Hunter Research Foundation estimates[9] that Tomago Aluminium supports 1,804 jobs and contributes $800 million per annum to the Gross Regional Production in the Hunter Region. It is also worth noting that as aluminium smelters are large constant loads that can be interrupted at short notice if required they contribute to system security.

Form of current standard

The current System Restart Standard (SRS) states:

"For each electrical sub-network, AEMO shall procure SRAS sufficient to:

- *re-supply and energise the auxiliaries of power stations within 1.5 hours of a major supply disruption occurring to provide sufficient capacity to meet 40 per cent of peak demand in that sub-network; and*
- *restore generation and transmission such that 40 per cent of peak demand in that sub-network could be supplied within four hours of a major supply disruption occurring.*

The restoration timeframe represents the 'target timeframe' to be used by AEMO in the procurement process. It is not a specification of any operational requirement that should be achieved in the event of a black system condition " [10]

There are three concerns with the form of the standard:

- The standard treats all loads within a sub-network equally.
- The standard does not specify outcomes for load restoration times on each electrical sub-network, nor does it reflect any concept of the reliability of restoration.
- As a result, the standard does not create any obligations on generators, TNSP's, DNSP's or AEMO to achieve final load restoration outcomes.

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[9] Hunter Valley Research Foundation, An Economic Assessment of Tomago Aluminium's activities in the Hunter Region

[10] Reliability Panel AEMC (2013) System Restart Standard

The standard treats all loads equally

Currently the sub-networks being used by AEMO for the purposes of procuring SRAS are essentially NEM regions except for Queensland where two sub-networks are used. These are all large geographic areas with a wide range of types of electricity customers with quite different exposures in the event of a black out. However as the standard only requires AEMO to look at the sub-network as a whole it implies that all loads are given equal treatment in spite of their different exposures.

It would be prudent to take into account the different economic exposures of customers and their different sensitivities to restoration times in determining the level of SRAS to be procured. For example businesses in CBD's, trains stalled in tunnels and aluminium smelters would be more time critical than other customers.

Does not specify load restoration outcomes

The standard could be characterised as an "input" standard in that it requires AEMO to source SRAS on the basis of being able to initially supply auxiliaries of generators and then have generation and transmission capacity available that could restore load within defined timeframes.

However it is clear that customers are seeking to understand when load will be restored. The current framing of the standard does not provide any clarity on when it is targeted to restore certain levels of load and in what locations. As a result it would seem to be more appropriate to define the standard in terms of outcomes to be achieved – or an "output" standard rather than as it is currently defined.

Lack of obligations

As indicated the current standard is a "procurement target" for AEMO. AEMO's only obligation is to procure sufficient SRAS to meet the standard. As a result of no load outcomes being specified in the standard, and the obligations this places on AEMO, there is little incentive to place secondary obligations on providers of SRAS, generators relying on their supply, TNSP's reestablishing the network or DNSP's to connect loads.

Without some form of obligation on each of these parties it is difficult to have any confidence about a timely restoration of supply to loads. In our view, having the standard focus on load restoration outcomes should facilitate the creation of obligations on the various facilities that are involved in system restoration. It is acknowledged that seeking to create strict liabilities for parties failing to achieve their obligations would be problematic in a black start situation but this should not prevent the creation of any obligation whatsoever.

Lack of economic trade-off

The current SRS appears to be derived from a technical basis and the current level of SRAS procured is based on a desire to reduce costs of SRAS.

It is clear from the analysis undertaken by ROAM [6] that the procurement of additional SRAS would have produced a net economic benefit. However incremental procurement was not undertaken.

AEMO state that the Value of Customer Reliability (VCR) for a commercial customer is $44.67/kWh or $44,670/MWh. Undertaking a simple analysis using this value indicates that the value of restoring 500 MW of commercial load 2 hours earlier is $1,788,000 for a 1 in 25 year probability of a black out or $894,000 for a 1 in 50 year probability of a black out.

This does not necessarily demonstrate that more SRAS should be acquired but it does indicate that there would be merit in assessing the trade off between the costs of additional SRAS compared to the benefits of restoring load more rapidly. Ideally more SRAS services should be acquired as long as the incremental benefit of doing so is greater than the incremental cost.

To do this will require an overarching economic framework that accounts for the tradeoff between the cost of a system black event, its frequency of occurrence and the cost and effectiveness of SRAS as a mitigation measure. This is essentially an insurance problem, but is further complicated by security of supply being a public good for which there is limited information about consumer willingness to pay.

As this assessment is an empirical question and subject to a number of region specific inputs and assumptions, it ought to be undertaken using more electrical sub-networks to take into account the geographic variations in the economic impacts of a major black out.

The absence of any economic framework in determining the SRS is a major deficiency in the current regulatory settings.

AEMO reliance on powers of direction

As a result of informal feedback from market participants regarding their conversations with AEMO staff it appears that AEMO is proposing to rely on its powers of direction in event of system black rather than creating commercial incentives for participants to contribute to restoration of supply in the event of a system black.

There are a number of problems with this approach:

- AEMO can only direct a market participant to act within its capabilities. If a participant has a potential capability that AEMO would seek to rely on, AEMO may not be aware that this capability is unavailable. An example of this could be AEMO assuming that because a gas turbine can run on oil that it is available to do this. The participant may have chosen to reduce the amount of oil stored on site, in which case AEMO directing them to run will be futile. Another example is AEMO assuming that a previous SRAS provider has maintained the capability offered under a previous SRAS contract which may no longer be available.
- Without commercial incentive participants are less likely to maintain the capability of their plant that may provide services in the event of a black start. This will over time reduce the capability of plant available for AEMO to direct.
- In the absence of an SRAS contract staff may no longer be available to perform any restart sequences.
- Even in the event that staff are available, in the absence of a SRAS contract, they may not have been appropriately trained and therefore not be capable of undertaking the necessary operations.

Validation and testing difficulties

Currently there is no real way of validating that AEMO has complied with the SRS when awarding SRAS contracts.

This difficulty is created by:

- The lack of transparency on which plant have been awarded SRAS contracts. This lack of transparency is puzzling given the very extensive publication of data, often in real time, on all other NEM outcomes. This confidentiality extends to the Reliability Panel itself, who is not informed of which generation are providing SRAS at any given time.
- AEMO does not publish its modeling and analysis of how it decided the level of SRAS contracts to award and the basis for expected restoration times under various scenarios.

Without the publication of this information it is not possible for participants or other interested parties to form a view on the extent to which AEMO has complied with the SRS. The lack of engagement by AEMO with market participants affected by the outcomes of the SRAS regime in place also contributes to this concern.

There is also no attempt to demonstrate how sensitive load schedules have been taken into account.

As outlined above the testing regime for black start providers does not necessarily provide a realistic test of the capability of the plant for an actual system black. This creates an unrealistic estimate of the actual reliability and as a result restoration times.

Recommendations for improvements

Revision of form of standard

Ideally the SRS should:

- Define the outcomes being sought rather than specifying a level of generation in service that could supply a proportion of load. I.e. the standard should move to an output basis form the current input basis.
- Provide for definition of sub-regions that group loads with particular economic characteristics or technical requirements and take into account network and generation limitations in supplying this sub-region. The key is to define sub-regions on the basis of the loads within that region and their requirement rather than determining this on a technical basis as is the current practice.
- For each sub-region define the amount of load that must be supplied within a defined time frame and a minimum reliability with which these outcomes will be achieved. These requirements will necessarily take into account the existence of sensitive loads in the sub-region. The reliability could be defined as levels of contingency that must be allowed for – such as N-1 or preferably with a specified minimum probability of success – say 95%.

  These parameters of the amount of load, the restoration time and the reliability should be determined on the basis of an economic trade off as outlined below.

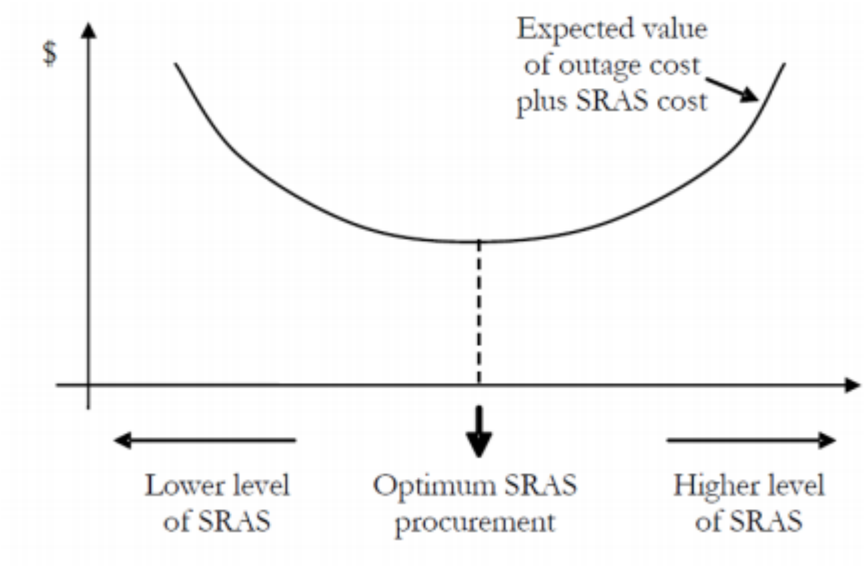
This approach is what is contemplated by the NER in 8.8.3 (aa).

One benefit of this approach is that if AEMO is obliged to put in place facilities to achieve these outcomes that this will imply that arrangements will have to put in place with TNSPs and potentially DNSPs to ensure the specified amount of load is restored in the required time frames.

Economic framework

The Reliability Panel will need to undertake an economic assessment to set the parameters required in the new SRS. Ideally, this would be based on an overarching cost benefit analysis that assesses the incremental value of additional SRAS services compared to the incremental cost. Welfare would be maximised at the point where total costs – defined as sum of the costs of a given level of SRAS and the expected cost of a black out accounting for its likely severity and probability of occurrence. The Reliability Panel highlighted this approach in its issues paper (reproduced below). To the left of the optimal point, incremental SRAS would involve marginal benefits that exceed the expected marginal costs of an event. To the right, the converse conditions hold were incremental SRAS involves a net determent on the margin.

Optimum level of SRAS Procurement[40]



AEMC, Reliability Issues Paper, Figure 3.1

This is not a simple task. Assessing this trade off involves quantification in three broad areas:

- **The expected cost of a black start event.** In general, rigorous quantification of high impact low frequency events is more difficult than events that occur more frequently (such that there is a larger sample of historical data to base the analysis on) and which involve more narrow impacts on the economy (as this reduces the number of interaction effects across different sectors and customer segments). This report has discussed a number of likely costs of a black out event but a more complete and systematic analysis would be required in any formal analysis.
- **The probability of an event.** Quantifying the probability of an event in subject to many of the same challenges as estimating the cost. The limited sample set of historical events and continuing evolution of power systems across the world provides only a limited basis to determine a robust probability of event frequency in the NEM. This report has presented a number of practical approaches for developing a reasonable range of event frequencies, however sensitivity analysis is almost certainly required on both probabilities and costs.
- **The cost of different levels and types of SRAS.** Whilst this is a much simpler quantification task it is by no means a trivial assessment. SRAS is properly thought of as a bundled service which spans a number of market participants – AEMO, the TNSPs, SRAS providers, other generators and the DNSPs. Quantifying costs for different elements on the overall service should be relatively straightforward, the more difficult task is combining different levels of SRAS with interactions across the rest of the market in a systematic manner such that a true SRAS supply curve can be developed.

There are further factors that would complicate the analysis.

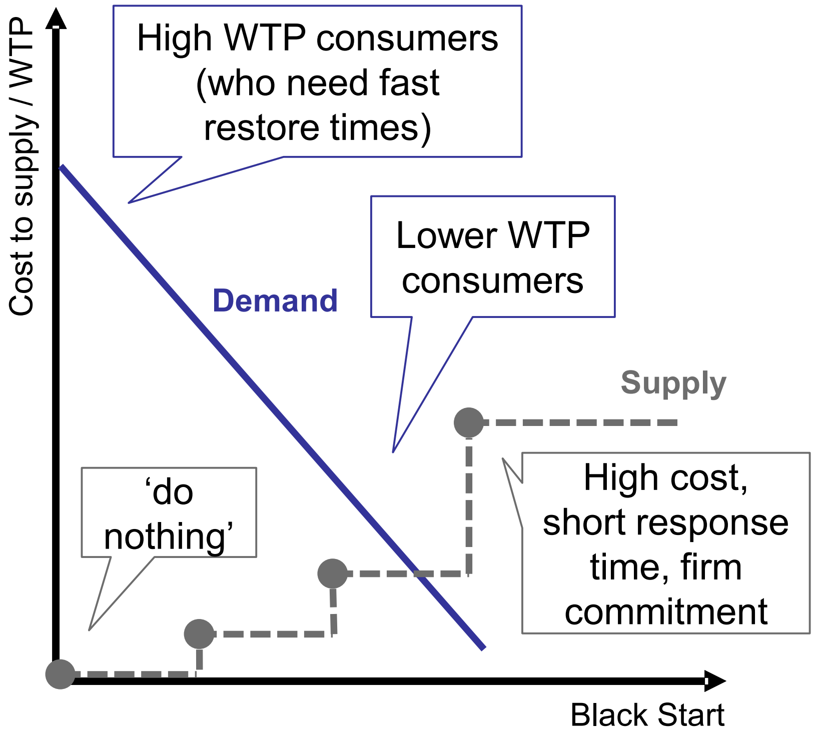
Accounting for uncertainty

Should the above variables be estimated on an expected basis or in a manner that accounts for some portion of the considerable uncertainty. Expected values are a useful starting point, at the other extreme stochastic modelling could be used to produce a distribution of the probability weighted costs of a black out event. The former approach, given the low probability nature of black outs, could produce a misleading result (in that the expected costs of a black out relative to the cost of more SRAS may result in a decision that is materially different to that which would be made if the more complete distribution of system black costs was known. In practice, it is likely that a pragmatic approach, such as considering sensible upper and lower bounds for each variable as part of a wider sensitivity analysis would be the preferred approach.

Willingness to pay and risk preferences

Consumers have varying willingness to pay for SRAS as insurance against interruptions in reliable supply. High value industrial or commercial consumers are likely to have a high willingness to pay for security of supply and may be risk averse. Conversely, some consumers may place relatively low value on avoiding short term interruptions to supply and be relatively risk neutral. This is further complicated by the 'public good' nature of system security.

If there was a 'market' for SRAS then it could be the case that declining wiliness to pay for SRAS would intersect at some level of supply. This would 'clear the market' and set both the level and price of SRAS services. This is illustrated below.



In practice, the public good nature of system security means that some agent needs to intermediate on behalf of all consumers and set both their willingness to pay and assume some risk preference when assessing outcomes.

AEMO has undertaken considerable work in estimating the value customers place on reliability (VCR).[11] This work has consider a range of customer segment and their relative weights in the market to arrive at a figure of $33.46/kWh or $33,460/MWh. We would note that this figure is considerably higher than the current wholesale market price cap of $13,800/MWh. AEMO's VCR figure is likely to be the best available estimate of consumers' willingness to pay for SRAS.

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11 AEMO, *Value of Customer Reliability*, September 2014

In terms of risk preference, there seems limited evidence to assume that, in aggregate, consumers are risk averse, risk neutral or risk loving. In such cases, an assumption of risk neutrality is a common and defensible approach.

Defining electrical sub-network and prioritising load

A final question arises in considering the basis on which electrical sub-networks are defined. This question is partly technical and partly economic to the extent that particular sub-network definitions may allow some sensitive loads to better express their higher willingness to pay as part of ensuring more rapid load restoration to such customers via higher SRS settings for that sub-network.

In some instances, accounting for such factors may be relatively clear cut. For example, in the case of smelters, a sub-network could defined as the smelter, nearby generators capable of starting and supplying the smelters at full load, network assets to facilitate this loading and any other loads that may be required during the reenergisation sequence. In other cases, like those on home life support or trapped in trains and lifts, it may be harder to selectively restore such customers or to define a sub-network that isolated them as a group.

Legal implementation

SRAS Objective - legal comments

The SRAS Objective is defined in Chapter 10 of the NER:

"The objective for system restart ancillary services is to minimise the expected costs of a major supply disruption, to the extent appropriate having regard to the national electricity objective."

The national electricity objective is set out in s7 of the National Electricity Law:

> *The objective of this Law is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to —*
>
> *(a) price, quality, safety, reliability and security of supply of electricity; and*
>
> *(b) the reliability, safety and security of the national electricity system.*

The NER defines a major supply disruption as:

> *…the unplanned absence of voltage on a part of the transmission system affecting one or more power stations and which leads to a loss of supply to one or more loads.*

Chapter 10 of the NER defines system restart ancillary service or SRAS as:

> *A service provided by facilities with black start capability which allows:*
>
> *(a) energy to be supplied; and*
>
> *(b) a connection to be established,*
>
> *sufficient to restart large generating units following a major supply disruption.*

Chapter 10 of the NER defines "facilities" broadly, encompassing a broad range of plant types, not just generating units, and could encompass network elements also, and could also include groupings of plant that included a black start capability.

Chapter 10 defines "black start capability" as:

> *A capability that allows a generating unit, following its disconnection from the power system, to be able to deliver electricity to either:*
>
> *(a) its connection point; or*

(b) a suitable point in the network from which supply can be made available to other generating units,

without taking supply from any part of the power system following disconnection.

The requirements of the SRAS Standard are specified under clause 8.8.3(aa) of the Rules, which states that:

The system restart standard must:

(1) be reviewed and determined by the Reliability Panel in accordance with the SRAS Objective;

(2) identify the maximum amount of time within which system restart ancillary services are required to restore supply in an electrical sub-network to a specified level, under the assumption that supply (other than that provided under a system restart ancillary services agreement acquired by AEMO for that electrical sub-network) is not available from any neighbouring electrical sub-network;

(3) include the aggregate required reliability of system restart ancillary services for each electrical sub-network;

(4) apply equally across all regions, unless the Reliability Panel varies the system restart standard between electrical sub-networks to the extent necessary:

(A) to reflect any technical system limitations or requirements; or

(B) to reflect any specific economic circumstances in an electrical sub-network, including but not limited to the existence of one or more sensitive loads;

(5) specify that a system restart ancillary service can only be acquired by AEMO under a system restart ancillary services agreement for one electrical sub-network at any one time;

(6) include guidelines to be followed by AEMO in determining electrical sub-networks, including the determination of the appropriate number of electrical sub-networks and the characteristics required within an electrical sub-network (such as the amount of generation or load, or electrical distance between generation centres, within an electrical sub-network); and

(7) include guidelines specifying the diversity and strategic locations required of system restart ancillary services.

Comments on the new Rules requirements

We note particularly that the SRAS Objective must be considered.

The SRAS Objective requires (1) a consideration of the expected costs of a major supply disruption, (2) a consideration as to how those costs would be minimised, and then (3) a determination as to what is the appropriate extent of minimisation having regard to the national electricity objective.

In addition to Guidelines to be made, the two key determinations that must be made for the Standard, according to the new Rules, are: (a) the maximum time and level of restoration of services for each electrical sub-network; and (b) the aggregate required reliability of SRAS for each electrical sub-network.

It is possible for the Panel to determine different times, levels and reliability for different electrical sub-networks.

The times, levels and reliability set by the Panel will be based on the assessment of the costs of disruption and how they can be minimised, consistent with the national electricity objective.

Submission to AEMC Reliability Panel in response to:

"Review of the System Restart Standard"

In determining the "aggregate required reliability of system restart ancillary services for each electrical sub-network" the reliability that ought to be considered is not just whether each facility will start and supply energy to the required connection point, and then aggregate that reliability, but instead what should be considered is the extent to which the facilities providing the SRAS services in an electrical sub-network can be relied upon, taken separately or in aggregate, to allow energy to be supplied and connections established "sufficient to restart large generating units following a major supply disruption" (using the definition of system restart ancillary service).

That is, the reliability is not just the reliability of the units with the black start capability, but rather the reliability with which the service objective of restarting large generating units and, ultimately, restoring load can be achieved.

Is the reliability required by the SRAS Standard to be sufficient to re-start just one large generating unit? Or multiple units? As Rule 8.8.3(aa)(2) requires the Panel to specify a maximum amount of time for which system restart ancillary services are required, to restore supply to a level (also specified by the Panel), we suggest that the reliability test referred to in 8.8.3(aa)(3) should be based on a sufficiency of service to meet that specified level within that specified maximum time frame.

A draft SRAS Standard is included in Appendix 1.

Improvements in validation and testing regimes

The effective validation of AEMO's implementation of the SRS is limited by two issues:

- The lack of transparency outlined above on both what has been implemented and the analysis that supports the decisions.
- The technical capability of regulatory agencies such as the AER to undertake the assessment required to validate AEMO's implementation of the SRS.

The most effective solution would appear to be to require AEMO to publish what arrangements are implemented (this would not need to include commercial terms), make available the necessary data and modeling results that support the decision on what arrangements to put in place. This would allow interested parties, such as market participants, to undertake independent analysis and if necessary challenge the choices made by AEMO. We note that such a requirement would be consistent with the level of transparency around the majority of other services provided by generators, including the provision of energy and all other ancillary services, where significant detail on bids, outcomes and future intentions are made available via AEMO in almost real time. Similarly, AEMO undertakes significant public consultation and provides for high levels of transparency in many of its other responsibilities from demand forecasting, to procedures for other services to ad hoc processes such as the Heywood upgrade RIT-T (in its role as system planner).

As outlined above the SRAS testing regime does not effectively provide a real world test of SRAS capability. This is very difficult to do. However some suggestions for improvement are:

- Increasing the frequency of black start tests for gas turbines that are providing SRAS.
- Conducting a number of black start tests, including those for TTHL with very short notice.

It is worth noting that other jurisdictions impose more stringent requirements on SRAS providers. For example, Singapore imposes a requirement for routine start testing on a monthly basis and mandates standardised reporting of both successful and unsuccessful tests.

Impact on costs and cost allocation of recommendations

One of the challenges of allocating costs with system security is the benefits are shared by all consumers even though they have differing willingness to pay for this benefit.

It is difficult to predict what the implications of the recommended changes would be on costs to electricity customers. However some observations can be made:

- Given that the recent 50% reduction in SRAS costs equated to a cost reduction of less than $2 per customer per year it is obvious that reversing this reduction is not a material cost.
- Any increase in SRAS costs resulting from these recommendations would only result from an economic assessment that would seek to find the optimum trade-off for customers between the cost of SRAS and their preference for restoration times.
- Given the shared nature of the benefit of improving restoration times it would be challenging to do anything other than allocate the costs on an average 'postage stamp' basis as is currently done.

Responses to questions in Issues Paper

Question 1 - Time and level of restoration

1. Are the existing timeframes for restoration appropriate (ie, 1.5 hours for restoration of station auxiliaries of generating units that can supply 40 per cent of peak demand in the sub-network and 4 hours for generation capacity equivalent to 40 per cent of peak demand)? If the timeframes are not appropriate, how should they be amended?
2. Do stakeholders consider that the restoration level be maintained at 40 per cent of peak load? If not, what other restoration level should be considered, and why (eg, a different percentage rate, or average demand instead of peak demand)?
3. Is the powering of auxiliaries as an intermediate step a necessary part of the definition of the Standard? What are the costs and benefits of removing the intermediate step and moving to a single timeframe for power system restoration (eg, restore 40 per cent of peak demand within 4 hours)?

As outlined above the recommended approach to defining the time and level of restoration is to define the quantity of load (in MW) to be restored within a nominated time frame in each sub-region with a defined level of reliability of achieving this outcome. It would be expected that these parameters could vary between sub-regions on the basis that the economic impact of restoration times would vary between sub-regions.

If this approach is adopted this implicitly requires assessments to be made of the time to restore supplies to auxiliaries, times for units to restart and time for loads to be supplied. Again these assessments would be expected to vary between sub-regions. It seems reasonable to allow AEMO to determine how best to meet the overall obligation as opposed to additionally setting specific intermediate timings and requirements that may in practice vary by sub-region.

The economic benefit of this approach is that it makes it possible to undertake an economic trade off between benefits of achieving load restoration time frames compared to the costs of achieving these time frames.

Question 2 - Aggregate reliability

1. What factors should the Panel consider in determining the level of aggregate reliability?
2. Would it be appropriate for the Standard to include a minimum number of SRAS services in each sub-region? What are the costs and benefits of doing so?

Critically, reliability should focus on outputs, final load restoration, as opposed to intermediate points in the restoration process. In determining the level of aggregate reliability for a sub-region the Panel should take into account the reliability of:

- SRAS providers
- Generating units that are restarting from external supplies
- The expected reliability of the planned network restoration

It would be expected that these factors would be different for each sub-region.

Rather than manage reliability by specifying a minimum number of SRAS services the Standard should define an aggregate reliability for each sub-region, based on an economic assessment. This reliability target would then be used to determine the number of SRAS sources that would be required in that sub-region. This would need to take into account the nature of the expected SRAS sources because as outlined above the reliability SRAS sources vary depending on the technology being applied.

Using this approach would provide flexibility in achieving the optimal level of SRAS in each sub-region, accounting for value of load restoration and region specific costs of SRAS.

Question 3 - Regional variation

3. What types of technical matters or limitations are likely to impact on achieving the Standard?
4. Are there any sub-networks in regions of the NEM where specific technical matters or limitations may be relevant to the Panel's determination of the Standard, including any potential variations to the Standard for any specific sub networks?
5. What types of economic circumstances or considerations should the Panel be mindful of when determining the Standard? How do they relate to the Standard?
6. Are there any sub-networks with specific economic circumstances, such as the presence of sensitive loads, that the Panel should consider when determining the Standard, including any potential variations to the Standard for any specific sub-networks?

The technical matters or limitations that are likely to impact on achieving the Standard are those listed above that would impact on aggregate reliability together with operational capability of AEMO and TNSP's to respond in the difficult circumstances that would be prevailing.

Given the recommendation that determination of the standard should be on an economic basis the manner in which known technical matters or limitations should be taken into account is in informing this economic assessment and not directly impacting the settings in the Standard.

As outlined above, the economic circumstances that should be taken into account in determining the standard would include:

- Costs of various forms of SRAS (covering black start generators and other sources)
- The reliability of these forms of SRAS
- The economic costs to electricity customers and the broader community of delays in restoring power supplies – noting that these economic costs will vary with geographic regions. For example the impact of delays in restoration would be more severe in locations such as CBD'S and regions that contain major loads such as smelters where delays in restoration time are critical.

Question 4 - Sub-network guidelines

What factors should the Standard require AEMO to take into account when setting sub-network boundaries? How are they relevant?

The recommended approach to setting sub-network or sub-regional boundaries is an economic one that takes into account the economic characteristics of the loads in a particular sub-region. This should be the dominant consideration and then AEMO should take into account any technical issues that may affect the restoration times for that sub-region such as:

- Network capability
- Potential SRAS and generation sources available

Given the economic nature of this assessment it may be appropriate for a body other than AEMO to be responsible for having the primary responsibility for determining appropriate sub-regions.

Question 5 - Diversity Requirements

1. Do stakeholders consider the existing diversity requirements in the Standard for the procurement of SRAS by AEMO to be appropriate?
2. Do the existing diversity requirements in the Standard for the procurement of SRAS by AEMO adequately create independence between different SRAS providers in the same sub-network?

The current diversity guidelines are fairly general and seem reasonable.

However the real issues is the expected aggregate reliability of whatever SRAS provisions are in place. This reliability analysis should inherently take into account the factors listed in the current diversity guidelines.

Conclusions

In conclusion it is clear that:

1. Major black outs can and do happen and that when they do the consequences can be severe. In an Australian context the fact what such an event has not happened in recent history does not mean that such an event could not occur in the future. In fact, as a result of changes in the technology mix for supply, if anything the risks are increasing.
2. In light of this risk it is essential arrangements be made to mitigate the effects of a major black out. The provision of black start services needs to include not only generators that can restart without external supplies but also generators that restart relying on black start sources and arrangements with network and system to achieve overall load restoration.
3. The risks of black start service providers failing are real and significant.
4. The risks of generators failing shortly after restarting are also real and significant.
5. Finally, the risks arising from the operational decisions made by TNSPs and DNSPs are real and significant.
6. On this basis it is clear that reducing the number of black start providers will materially increase the risk of major delays in the time taken to restore load in the event of a major black out.
7. It is worth noting that the recent 50% reduction in SRAS costs equated to a cost reduction of less than $2 per customer per year.
8. It is also clear that the current arrangements are unlikely to achieve the outcomes required in the current System Restart Standard with specified times for generation to be able to supply load not being achieved.
9. The provision of black start services is in effect an insurance policy to mitigate the effects of a major black out.
10. As a result of black start being an insurance type product the level of insurance acquired, in terms of the reliability and the restoration times for loads, should be determined on the basis of an economic trade-off. This trade-off should be between the benefits of increasing the effectiveness of the insurance and the increasing cost of purchasing it. This is in contrast to the largely technical approach currently used.
11. Given that this economic trade-off should is likely to differ across the system, predominantly as a function of the sensitivity of load to black outs, electrical sub-networks under the standard should also be defined with regard to the economics of restoration time for loads within that sub-network. This would allow for the level of SRAS to vary in proportion to the value that loads within that sub-network place on restoration time.
12. The current arrangements do not provide any clarity or certainty for electricity customers on expected restoration times. This should change and the requirements for black start arrangements should be on the basis of achieving outcomes in terms of restoring load.
13. The new rules relating to the System Restart Standard provide the legal framework for the Reliability Panel to implement the changes recommended in this submission.

Appendix 1

Proposed System Restart Standard - Example

1. Introduction

This System Restart Standard (standard) was determined by the Reliability Panel (Panel) in accordance with clauses 8.8.1(a)(1a) and 8.8.3 of the National Electricity Rules (Rules). The purpose of this standard is to provide guidance and set a benchmark to assist the Australian Energy Market Operator (AEMO) in procuring sufficient system restart ancillary services (SRAS) to meet the requirements of the National Electricity Market (NEM). This standard is effective from [insert date].

2. Requirements of the standard

The requirements of the standard are specified under clause 8.8.3(aa) of the Rules, which states that:

The system restart standard must:

(1) be reviewed and determined by the Reliability Panel in accordance with the SRAS Objective;

(2) identify the maximum amount of time within which system restart ancillary services are required to restore supply in an electrical sub-network to a specified level, under the assumption that supply (other than that provided under a system restart ancillary services agreement acquired by AEMO for that electrical sub-network) is not available from any neighbouring electrical sub-network;

(3) include the aggregate required reliability of system restart ancillary services for each electrical sub-network;

(4) apply equally across all regions, unless the Reliability Panel varies the system restart standard between electrical sub-networks to the extent necessary:

(A) to reflect any technical system limitations or requirements; or

(B) to reflect any specific economic circumstances in an electrical sub-network, including but not limited to the existence of one or more sensitive loads;

(5) specify that a system restart ancillary service can only be acquired by AEMO under a system restart ancillary services agreement for one electrical sub-network at any one time;

(6) include guidelines to be followed by AEMO in determining electrical sub-networks, including the determination of the appropriate number of electrical sub-networks and the characteristics required within an electrical sub-network (such as the amount of generation or load, or electrical distance between generation centres, within an electrical sub-network); and

(7) include guidelines specifying the diversity and strategic locations required of system restart ancillary services.

3. Applicability of the standard in electrical sub-networks

This standard shall be determined for each electrical sub-network.

4. Restoration timeframe

For each electrical sub-network, AEMO shall procure SRAS sufficient to restore [insert MW of load] MW of load within [insert hours] hours with a reliability [**% - here insert the reliability factor that the Panel determines best minimises costs within the objective for this electrical sub-network].

6. Procurement

A system restart ancillary service can only be acquired by AEMO under a system restart ancillary services agreement for one electrical sub-network at any one time.

7. Guidelines for the determination of electrical sub-networks

AEMO shall determine the boundaries for electrical sub-networks without limitation by taking into account the following factors {to be determined}:

[•the economic characteristics of the load within the electrical sub-network, particularly sensitive loads;

•the technical characteristics of the electrical sub-networks (for example, the number and strength of transmission corridors connecting an area to the remainder of the power system and the electrical distance (length of transmission lines) between generation centres.

•the quantity of generation in an area, which should be in the order of 1000MW or more; and

•the quantity of load in an area, which should be in the order of 1000MW or more].

8. Guidelines for specifying the diversity and strategic location of services

[There shall be diversity in the SRAS procured by AEMO to provide an appropriate level of independence between the services procured and in order to achieve the aggregate required reliability specified for each electrical sub-network at item 5 of this standard. AEMO shall consider diversity of the services by taking into account the following guidelines {to be determined}:

[•Electrical -diversity in the electrical characteristics shall be considered particularly with respect to whether there would be a single point of electrical or physical failure;

•Technological - diversity in technologies shall be considered to minimise the reliance of services on a common technological attribute;

•Geographical -diversity in geography shall be considered to minimise the potential impact of geographical events such as natural disasters; and

•Fuel - diversity in the type of fuel utilised by services shall be considered to minimise the reliance on one particular fuel source.]