AEMO responsibilities to procure SRAS

DNV KEMA independent review

Australia Energy Market Operator

30 December 2013

Newport power plant turbine hall

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Abbreviations and nomenclature

AC	Alternating current
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
BSU	Black-start unit—a generating unit that can start and deliver power to the grid without external power supply
EHV	Extra high voltage, generally referring to facilities operating at or above 100 kV
EMTP	Electro-magnetic transient program, a computer model that evaluates very rapid system changes
Generating plant	A power station (also referred to as a generating station, power plant, powerhouse or generating plant) that generates of electric power that includes one or more generating units.
Generating unit	A single electric generator, a rotating machine that converts mechanical power into electrical power
HVDC	High voltage direct current
kV	kilo Volts, !,000 volts
MW	Mega Watt, a million Watts
NEM	Australian National Electricity Market
NER	Australian National Electricity Rules
NSW	New South Wales
Power plant	See generating plant
Power station	See generating plant
QLD	Queensland
Regional network	The electrical transmission network in each of the five regional networks in the NEM—Queensland, New South Wales, Victoria, South Australia, and Tasmania
SRAS	System Restart Ancillary Services
SRS	System Restart Standard
State network	Regional network
Sub-network	A sub-area of a regional network as defined in NER §3.11.4B for the purpose of acquiring SRAS
Substation	Connects two or more transmission lines and may transform voltages
TNSP	Transmission network system providers
Transmission circuit	Transmits electrical energy between substations with conductors for only one circuit

Transmission line	Transmits electrical energy between substations on a single set of towers or pylons with conductors for one or more circuits
TTHL	Trip-to-house load, the ability of a generator to remain operating after being disconnected from the network
UFLS	Under-frequency load shedding
USB	Universal system bus–a connection type to personal computers

Executive summary

The Australian Energy Market Operator (AEMO) was established to manage the National Electricity Market (NEM) and gas markets from 1 July 2009. The AEMO is the NEM energy market operator and planner. DNV KEMA Energy & Sustainability was engaged by the AEMO to perform and independent review of specific aspects of how the AEMO provides generating capacity to restore the system following a major blackout.

The AEMO operates within a broader market governance structure alongside the Australian Energy Market Commission (AEMC) and the Australian Energy Regulator (AER). The AEMO's functions are prescribed in the National Electricity Law while procedures and processes for market operations, power system security, network connection and access, pricing for network services in the NEM and national transmission planning are all prescribed in the Australian National Electricity Rules (NER).

The NEM electric network

The NEM operates the world's longest interconnected power system—from Port Douglas in Queensland to Port Lincoln in South Australia—a distance of around 5,000 km. More than $10 billion of electricity is traded annually in the NEM to meet the demand of more than eight million end-use consumers. It includes almost 50,000 MW of generation serving about 40,000 MW of customer load.

The NEM transmission networks, historically, evolved as individual networks within each state. These states had limited interconnection between them that limited power interchange. (This is a common pattern seen in North America and Europe.) While the interconnections have been strengthened over the years, they still have relatively strong internal transmission networks with limited interstate interconnections. By at least one technical rule of thumb, all these interstate connections would be considered as "weak", especially New South Wales–Queensland.

System Restart Ancillary Services

The objective for System Restart Ancillary Services (SRAS) is to minimize the expected economic costs to the market in the long term and, in the short term, the cost of any major supply disruptions that occur. The AEMO must try to acquire enough "primary" SRAS by entering into ancillary services agreements in each electrical sub-network. In the event that adequate primary restart services are not available the NER currently define a lower quality "secondary" SRAS as an option

The system restart standard (SRS) is determined by the Reliability Panel to meet the requirements of the NER. Some of the specific requirements of the SRS including:

- Target times for restoration;
- SRAS reliability; and

- Electrical sub-network boundaries:

AEMO assignment for DNV KEMA

In early September the AEMO engaged DNV KEMA to review certain aspects of the AEMO's responsibilities to procure SRAS. Specifically, DNV KEMA was asked to review:

1. Comment on the relative probability of a NEM-wide versus region-wide blackout, and the appropriateness of the proposal to procure SRAS to meet the SRS from a region-wide, rather than a NEM-wide blackout;
2. Review and comment on AEMO's rationale for defining electrical sub-networks;
3. Review and comment on AEMO's proposed changes to the definition of SRAS;
4. Review and comment on AEMO's assessment of the quantity of SRAS;
5. Review the assumptions, basis and methodology for AEMO's modelling SRAS;
6. Compare the likely performance of current and proposed SRAS;
7. Review and comment on the relative impact of AEMO's proposed revised SRAS guidelines for:
    a. Meeting the SRS;
    b. The subsequent restoration of load in each sub-network; and
    c. Overall achievement of the System Restart Objective;

DNV KEMA Energy & Sustainability is an independent consulting organisation, which is not affiliated with particular products, technologies or suppliers. DNV KEMA is unique in that in addition to consultancy services it is also a major independent testing and certification authority for the utility sector. The company employs more than 2,300 experts in over 30 countries around the world.

Proposed changes addressed by DNV KEMA

The seven issues being reviewed here by DNV KEMA fall into three major areas:

1. The probability of the assumed blackout condition—NEM-wide versus state-wide;
2. The number of sub-networks and SRASs in each; and
3. The SRAS definition, quantity and assessment.

The changes being proposed by the AEMO are summarized in Table 1. DNV KEMA's review of each of these is addressed in the following chapters.

Table 1: Proposed changes being addressed by DNV KEMA

Subject	Now		Proposed	
Assumed blackout condition	NEM-wide		Region-wide	
Number of SRAS	Generally two per sub-network		Generally one per sub-network	
	Sub-network	SRAS/region	Sub-network	SRAS/region
Queensland	3	6	2	2
New South Wales	2	5	2	2
Victoria	2	4	1	1
South Australia	1	3	1	1
Tasmania	2	3	1	2
Total	10	21	7	8
SRAS definition	Primary and secondary		Only one definition	
	Focus on SRAS rapidly energizing auxiliary supply bus of large generating units		Focus on rapidly delivering SRAS power to the transmission system	

DNV KEMA prepared this report by reviewing a wide range of publicly-available documents and selected confidential documents, discussing various aspects of the NEM electric system with AEMO staff, and our past international experience and engineering judgment. No technical analyses were made other than those described in this report.

Blackout probability—NEM-wide versus state-wide

The AEMO now applies the underlying assumption that a NEM-wide blackout occurs in determining SRAS. With this assumption, each region must provide enough SRAS resources to restart their individual systems. At some point, systems would be able to re-establish their interconnections allowing the states to assist each other. However, there is no requirement in the NER or SRS to assume such a NEM-wide blackout for determining SRAS.

In a NEM-wide blackout it would likely be several hours before neighboring systems could assist their neighbors in the restart process. With a regional blackout, on the other hand, neighboring systems should be available to assist in the restart process in a matter of minutes. This difference is the main change being proposed by the AEMO—that neighboring systems will be the primary restart source following a regional blackout.

The AEMO notes that:

- In the event of a major disturbance the national grid is very likely to separate at the weak points; the regional boundaries;
- The NEM has not experienced a system-wide (or even a region-wide) outage following some recent major events;
- Region-wide blackout conditions were the standard before deregulation; and
- If a NEM-wide blackout were to occur in the future, however unlikely, the system could still be restored, but restoration might take longer with the new SRAS approach.

Lessons from other blackouts

There are as many different causes of blackouts as there are blackouts—each is somewhat unique. There are, however, several common patterns that can be seen in blackouts. At the highest level, there are two major categories—controlled and uncontrolled blackouts.

In a controlled blackout system operators (or automated control devices) actively disconnect loads to prevent a larger blackout. Such a situation can occur, for instance, when there is a fuel shortage that reduces the total or regional system generating capacity. System operators disconnect customer load to maintain a balance between load and generation. Controlled blackouts may last for hours but only part of customer load is out of service at any time and the outages are rotated among customers so that they are only out part of the time.

Uncontrolled blackouts occur unexpectedly and are usually what the public means when they discuss blackouts. All uncontrolled blackouts begin with an unplanned system "event" that causes a sudden change in the load-generation balance—usually when a large amount of generation is suddenly lost.

The uncontrolled major system blackouts that have occurred around the world usually happened because there was not enough transmission to maintain the necessary connections between load and generation, or because there were inadequate resources to support system voltage. In uncontrolled blackouts the system conditions typically change too rapidly for human response, so automatic protection devices installed in the system will rapidly disconnect generation units and transmission system equipment. This phenomenon is commonly called a "cascading outage".

Such a cascading outage usually continues until it reaches a transmission break point—often the interconnection between adjacent regions or systems. Such break points are reached when there is not enough transmission capacity connecting the "problem area" with the remaining portions of the system. In most cases this will stop the cascade process by isolating the problem area from the rest of the system.

Transmission break points in the NEM

Based on a review of the NEM transmission system maps and the locations of load and generation, and relying on engineering judgment, several likely transmission break points were identified.

In this review we identified transmission break points considering three factors from the SRS:

1. The number and strength of transmission corridors;
2. The amount of generation and load in an area; and
3. The electrical distance between load/generation centers.

In particular, the strength of transmission corridors was determined using a transmission "cut-plane" approach. The cut-plane approach we used counted the number and voltage levels of the lines that could separate two areas in the transmission system. More circuits and higher voltages indicate higher transmission corridor capability. The goal was to find transmission corridors between areas that had the least capability that would likely be the cut-plane where the transmission would separate during a major disturbance.

Queensland

There appear to be two transmission break points in Queensland one in the center of the state north of Brisbane and one in the area bordering New South Wales. The central Queensland break point will likely lie along the existing sub-network boundary between south and central Queensland.

The southern Queensland break point is more uncertain and interesting. The current sub-network boundary lies along the inter-state border between Queensland and New South Wales and includes two 330 kV AC circuits and one HVDC circuit.

We believe that the southern Queensland break would more likely occur farther south along a suggested boundary that also includes two 330 kV circuits but with a third circuit that is at a lower voltage. In addition, there is a kind of transmission loop between Armidale and Coffs Harbour in the south and Millmerran in New South Wales and the Brisbane area to the north. This transmission loop is likely to remain intact following a serious disturbance with the break point to the south.

We agree with the AEMO that there should only be two sub-networks in Queensland. We suggest an alternate south Queensland boundary.

For a complete discussion, see §3.3.1 beginning on page 50.

New South Wales

New South Wales is now divided into two sub-networks along a sub-network boundary that splits a major transmission loop just north of Sydney that includes about 13,000 MW of generation. The system is very unlikely to split along the existing sub-network boundary as it is so electrically strong—it includes four 500 kV and six 330 kV circuits. Therefore, this is not a likely transmission break point as we have defined it in this review.

Our suggested boundary is the same as described above for southern Queensland. This suggested break point includes two 330 kV and one lower voltage circuit. We believe the system is much more likely to split along the suggested boundary than the existing New South Wales sub-network boundary.

We agree with the AEMO that there should be two sub-networks in New South Wales. We suggest an alternate north New South Wales boundary.

For a complete discussion, see §3.3.2 beginning on page 51.

Victoria

Victoria now includes two sub-networks and boundaries with New South Wales and South Australia. The interstate boundaries with New South Wales and South Australia are both transmission break points.

We believe there are no break points within Victoria and, thus, we agree with the AEMO's suggested reduction to one sub-network.

For a complete discussion, see §3.3.3 beginning on page 52.

South Australia

South Australia is now treated as a single network. South Australia is interconnected with Victoria through a 500/275 kV interconnection to Heywood and an HVDC connection to Red Cliffs. There is no obvious internal transmission break point.

We agree with the AEMO—there is no need for two sub-networks in South Australia.

For a complete discussion, see §3.3.4 beginning on page 52.

Tasmania

Tasmania is now divided into two sub-networks and it also has a HVDC connection with Victoria. The existing sub-network boundary includes two 220 kV and one 110 kV circuits between Palmerston and Waddamana.

We agree with the AEMO—there is no need for two sub-networks in Tasmania as there is no likely transmission split point.

For a complete discussion, see §3.3.5 beginning on page 52.

NEM-wide versus region-wide probabilities

There are many possible events that could trigger a blackout. They range from an equipment failure to natural disasters or deliberate attacks. We group the possible trigger events into three categories:

1. Accidental;
2. Natural disasters; and
3. Deliberate attacks.

The probabilities and extent of various possible triggering events are summarized in Table 6 on page 40.

Accidental trigger events

There is a wide range of accidents that can trigger small system outages from utility field crew errors to traffic accidents and equipment failures that affect individual transmission structures. Such accidents, while common, have very limited impacts on the power system and its customers.

Substation accidents and equipment failures that might damage substation equipment occur on all systems. They range from damaged breakers to fires or collapsing cranes. This category often involves errors/accidents during construction or maintenance.

Fuel supply accidents and disruptions can and do occur. The fuels used in the NEM are coal, natural gas and water. The possible disruption causes would be different for each fuel type. We believe that only natural gas supply accidents/disruptions might cause some limited uncontrolled customer outages within South Australia.

Misoperation is a catchall group for various human actions or equipment malfunctions. We believe that human errors are more likely to have a wider impact than any equipment failure. The most serious misoperations would likely occur at the regional operating centers. It would be at these centers where an error could affect multiple generating units or transmission facilities. Such misoperation would have to be fairly extensive—affecting multiple transmission elements and/or generating units.

Natural disasters

Australia has experienced all major types of natural disaster—floods, fires, earthquakes, and geomagnetic storms. All of these can be serious events that will disrupt the electric system. However, each of them would only have limited geographic scope.

Deliberate attacks

Electric power systems have been subjected to physical attacks for many decades. Transmission line insulators have been used for random target practice as well as the occasional eco-terrorist or disgruntled/disturbed individual. These rarely have any significant impact on electric supply.

Cyber-attacks are a potentially serious matter. In power systems there could be specific equipment attacks or attacks on systems. There could also be a general attack such as a distributed denial-of-service attack.

A cyber-attack on a generator, transmission substation, or fuel supply would be very unlikely and would have only a limited effect on the system. A direct physical attack, however, would be almost as effective and require much less sophistication.

A cyber-attack directed at the AEMO national dispatch center would have no serious affect because the AEMO has no direct control of equipment, and instructions are given verbally. The remaining vulnerable targets are the regional operating centers that have direct control of the transmission system. Since the control centers in each of the five NEM regions has different equipment vendors or versions of control software there is no single cyber-attack that could affect them all.

So while the chance of a cyber-attack on any region would be very low, an attack that would affect more than one region is nearly impossible. Such an attack could bring down a region, but as discussed above, the blackout would be limited by the existing transmission break points to that region.

Defining sub-networks

The SRS provides guidelines for determining electrical sub-networks, specifically, that the AEMO determine the boundaries for electrical sub-networks without limitation by taking into account: The number and strength of transmission corridors; the electrical distance between generation centers; and the amount of generation and load in an area (at least 1,000 MW).

In their *System Restart Ancillary Services–Draft Report* the AEMO proposes that only one SRAS resource be procured for each sub-network and that some sub-networks be combined. The suggested changes were shown in Table 1, above. In short, the AEMO proposes that the total number of sub-networks be reduced from10 to 7:

- **Queensland**—as discussed above, we agree with the AEMO that the existing north and central sub-networks should be combined. We suggest an alternate boundary between south Queensland and New South Wales.
- **New South Wales**—as discussed above, we agree with the AEMO that New South Wales should include two sub-networks. We suggest and alternate boundary for north New

South Wales. We believe that the resulting "main" New South Wales sub-network should have two SRAS.

- **Victoria**— as discussed above, we agree with the AEMO that Victoria should be a single sub-network.
- **South Australia**— as discussed above, we agree with the AEMO that South Australia should remain a single sub-network.
- **Tasmania**— as discussed above, we agree with the AEMO that Tasmania should be a single sub-network with two SRAS.

SRAS definition, quantity and assessment

As defined by the NER, SRAS is a service provided by facilities with black start capability. Specific SRAS performance targets are delineated by the Reliability Panel in the SRS stating that the AEMO shall procure enough SRAS to ensure that, following a blackout, the resources can:

- Within 90 minutes, energize the auxiliaries of power stations with the capacity to meet 40% of peak demand in that sub-network; and
- Within four hours, restore generation and transmission with enough capacity to supply 40 per cent of peak demand in that sub-network could be supplied.

These restoration times represent 'targets' to be used by AEMO in the procurement process. They are not a mandatory operational requirement to be achieved in the event of a blackout. The AEMO does not propose any change to these Reliability Panel targets now.

The AEMO has experienced a number of undesirable outcomes with the current SRAS approach. Some winning SRAS tenders are able to energize the auxiliary bus of a specified large generator within 90 minutes, but that the specified generator is either unable to restart within four hours or unable to effectively deliver power from that plant to other large plants within four hours.

In other cases the AEMO reports that insufficient primary SRAS tenders have been received to meet the targets and that AEMO has then had to rely on secondary SRAS tenders in an attempt to close the gap. As a result of such issues, the AEMO is concerned that in an actual blackout it might be unable to meet the SRS restoration targets. The AEMO now proposes to remedy this perceived shortcoming through a redefinition of the SRAS tender requirements.

In its new approach, the AEMO proposes connecting SRAS generation output to a nearby transmission bus as quickly as possible. This would allow the AEMO to route power over the grid to the auxiliary busses of other power stations more quickly, flexibly, and effectively than it can in the current approach. By introducing this change, along with other changes to the SRAS definition, the AEMO seeks to develop a portfolio of tenders that will have a higher likelihood of meeting the 90-minute and 4-hour targets of the SRS.

We observe that in both the current regime and the proposed regime there is a given portfolio of generation resources in the NEM. Some of these resources have black-start capability, but many do not. It is unlikely that the proposed approach will incentivize construction of new black-start generation resources. However, it is possible that the new approach allow more of the existing black-start resources in NEM to participate in the SRAS tender process and, in some cases, might even encourage other generation owners to consider making minor modifications that would enable them to submit an SRAS tender.

We further conclude that the AEMO's proposed changes to SRAS tender requirements and definitions should improve the likelihood of meeting the SRS targets and make the tender process more competitive by allowing or encouraging more tenders to be submitted in future SRAS solicitations. In the body of the report, we examine each of the AEMO's proposed changes in SRAS definitions and tender requirements and opine on their potential benefits.

Finally, we observe that a more rigorous AEMO technical assessment process for SRAS tenders would improve the likelihood of actually meeting the SRS targets. In the body of the report we provide a preliminary outline for a more rigorous a technical assessment methodology for consideration by the AEMO.

DNV KEMA findings

Regarding NEM-side versus regional blackouts:

- While the AEMO now assumes a NEM-wide blackout in determining SRAS requirement; there is no such requirement in the NER, or SRS;
- The AEMO proposes to use region-wide blackouts as the basis for future SRAS requirements;
- We do not believe there is any credible event that could cause a NEM-wide blackout;
- We also believe there are relatively few events that could cause a region-wide blackout; and
- We, therefore, agree with the AEMO's proposed change.

Regarding sub-network definitions:

- The AEMO proposes to reduce the number of sub-networks from ten to seven;

- We generally agree that the number of sub-networks should be reduced, however, we would combine a revised north New South Wales sub-network with that of south Queensland. This change would further reduce the number of sub-networks to six;
- We believe that the resulting main New South Wales sub-network should have two SRAS; and
- We recommend that the AEMO use transmission break points as the basis for determining sub-network boundaries in the future.

Regarding SRAS definitions, quantities and assessment:

- With the present approach, it is possible for an SRAS to be unable to effectively meet the SRS target to serve 40% of peak load within 4 hours;
- We believe the new approach would make it possible for more of the existing black-start resources in NEM to participate in the SRAS tender process, making the process more competitive;
- We believe that the AEMO's proposed changes to SRAS tender requirements and definitions should improve the likelihood of meeting the SRS targets, especially supplying 40% of peak load within four hours; and
- We recommend a more rigorous AEMO technical assessment process for SRAS tenders to improve the likelihood of actually meeting the SRS targets.

1. Introduction

1.1 The Australian Energy Market Operator

The Australian Energy Market Operator (AEMO) was established to manage the National Electricity Market (NEM) and gas markets from 1 July 2009. The AEMO is the national energy market operator and planner. The AEMO supports the industry in delivering a more integrated, secure, and cost-effective national energy supply.

The AEMO is 60% owned by government members and 40% by industry members and operates under the governance of a Board that includes nine skills-based non-executive Directors and the Chief Executive Officer. The AEMO operates within a broader market governance structure alongside the Australian Energy Market Commission (AEMC) and the Australian Energy Regulator (AER). The AEMC determines the policy environment and governance structures that shape Australia's developing energy markets and which set the operating requirements and obligations of market participants.

The NEM is a wholesale market for supplying electricity to retailers and end-users in Queensland, New South Wales, the Australian Capital Territory, Victoria, South Australia and Tasmania. Operations are based in five interconnected regions that largely follow state boundaries.

The NEM operates the world's longest interconnected power system—from Port Douglas in Queensland to Port Lincoln in South Australia—a distance of around 5,000 km. More than $10 billion of electricity is traded annually in the NEM to meet the demand of more than eight million end-use consumers.

1.1.1 AEMO role and functions

The AEMO's functions are prescribed in the National Electricity Law while procedures and processes for market operations, power system security, network connection and access, pricing for network services in the NEM and national transmission planning are all prescribed in the Australian National Electricity Rules (NER).

The AEMO's core functions include:

- Electricity Market—Power System and Market Operator;
- Gas Markets Operator;
- National Transmission Planner;
- Transmission Services; and
- Energy Market Development.

1.1.2 DNV KEMA

DNV KEMA Energy & Sustainability is an independent consulting organization, which is not affiliated with particular products, technologies or suppliers. DNV KEMA is unique in that in addition to consultancy services it is also a major independent testing and certification authority for the utility sector. The company now employs more than 2,300 experts in over 30 countries around the world, is committed to driving the global transition toward a safe, reliable, efficient, and clean energy future. With a heritage of nearly 150 years, we specialize in providing world-class, innovative solutions in the fields of business & technical consultancy, testing, inspections & certification, risk management, and verification. As an objective and impartial knowledge-based company, we advise and support organizations along the energy value chain: producers, suppliers & end-users of energy, equipment manufacturers, as well as government bodies, corporations and non-governmental organizations. DNV KEMA is part of DNV, a global provider of services for managing risk with more than 10,000 employees in over 100 countries.[1]

As of 1 March 2012, KEMA Australia Pty Limited became part of DNV KEMA and has provided consulting services to power utilities across Australia. Australia DNV KEMA has built up a large network of customers that have enabled DNV KEMA to become an involved and experienced consultant in the Australian energy market.

1.2 The NEM electric network

1.2.1 Load and generation capacity

The NEM extends from Port Douglas and Cairns in northern Queensland, runs through Brisbane, Sydney, Melbourne and Adelaide to Port Lincoln in South Australia, and, by an HVDC connection, to Tasmania. It includes almost 50,000 MW of generation serving about 40,000 MW of customer load as shown in Table 2. We believe this is the longest (geographically) integrated power network in the world. The table also shows the largest generating plant in each state.

1. For more information on DNV KEMA, visit www.dnvkema.com.

Table 2: Regional generation, load and largest generating plant

State	Generation	Load	Largest generating plant	
			Name	Size
Queensland	12,500 MW	8,950 MW	Gladstone	6 x 280 = 1,680 MW
New South Wales	16,500 MW	14,750 MW	Eraring	4 x 720 = 2,880 MW
Victoria	12,400 MW	10,600 MW	Loy Yang	4 x 560 =2,240 MW
South Australia	5,500 MW	3,400 MW	Torrens Island	4 x 200 = 800 MW
Tasmania	2,700 MW	1,800 MW	Gordon	432 MW
Total	49,600 MW	39,500 MW*		

Note: * The total NEM load shown is a non-coincident amount. Since some regions' peak loads occur in winter and others in summer, the total NEM load is never as high as shown.

1.2.2 The transmission network

The NEM transmission networks, historically, evolved as individual networks within each state. These states had limited interconnection between them that limited power interchange. (This is a common pattern seen in North America and Europe.) While the interconnections have been strengthened over the years, they still have relatively strong internal transmission networks with limited interstate interconnections. This general pattern can be seen in Table 3 showing the state loads and interconnection capability between the states.

Table 3: Inter-regional interconnections

Inter-regional connection		Interconnection		
To	From	Connection	Capacity*	% of generation capacity
Queensland	New South Wales	2x330 kV & HVDC	520 MW♦	4.2
New South Wales	Queensland	2x330 kV & HVDC	1,420 MW	20.7
	Victoria	3 x 330 & 1 x 220 KV	2,000 MW♦	
Victoria	New South Wales	3 x 330 & 1 x 220 KV	1,900 MW†	25.6
	South Australia	2 x 275 KV & HVDC	680 MW◊	
	Tasmania	HVDC	590 MW	
South Australia	Victoria	2 x 275 kV	680 MW	12.4
Tasmania	Victoria	HVDC	480 MW	17.8

Notes:
* These are normal interconnection limits that may vary depending on specific system conditions. The AEMO publishes quarterly reports on interconnector performance that provides more detail.
♦ During some off-peak load conditions the NSW-QLD limit is 670 MW and the VIC-NSW limit is 3,000 MW.
† Amount varies depending on the output level of Murray generation.
◊ The amount varies between 670 and 695 MW.

While there are no universally accepted measures as to what constitutes a "strong" interconnection, one measure uses twice the largest power plant in an area as a benchmark.[2] Table 4 shows the ratio of the import capability to the largest plant size in each region. This ratio is well below the "two-times-largest-plant" rule of thumb that would indicate a strong interconnection for all of the regions, especially Queensland. The concept of strong and weak interconnections will be important when discussing transmission break points introduced in Chapter 2, below.

2. Casazza, J A and P J Palermo, *Analysis of the Evolution of Interconnections Between Regions in the U.S.A. Applicable to Developing Countries*, Electric Power Systems in Developing Countries, Symposium 11-85, Dakar 1985.

Table 4: Regional largest generating plants and import capability

Region	Largest plant	Import capability*	Ratio
Queensland	Gladstone 1,680 MW (6 x 280 MW)	520 MW	0.31
New South Wales	Eraring 2,880 MW (4 x 720 MW)	3,420 MW	1.19
Victoria	Loy Yang A 2,240 MW (4 x 560 MW)	2,170 MW	0.97
South Australia	Torrens Island 800 MW (4 x 200 MW)	680 MW	0.85
Tasmania	Gordon 432 MW	480 MW	1.11

Notes: * These are normal interconnection limits that may vary depending on specific system conditions. The AEMO publishes quarterly reports on interconnector performance that provides more detail.

Figure 1: NEM system transmission voltages

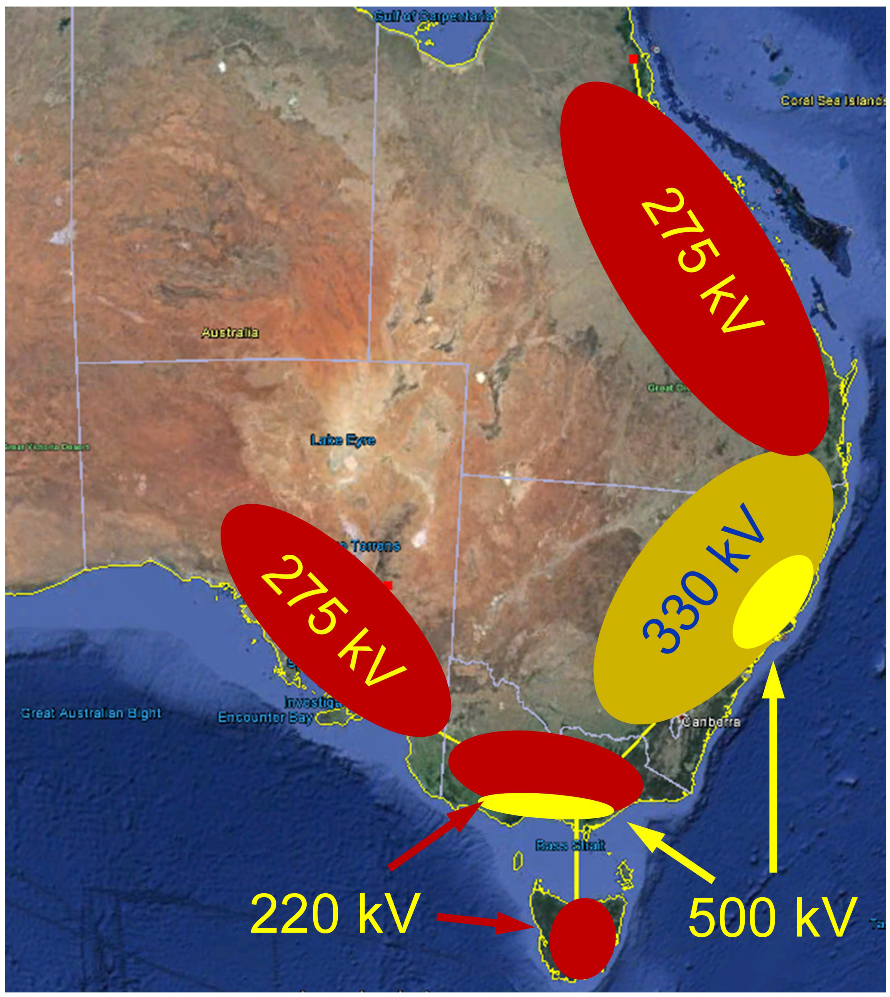
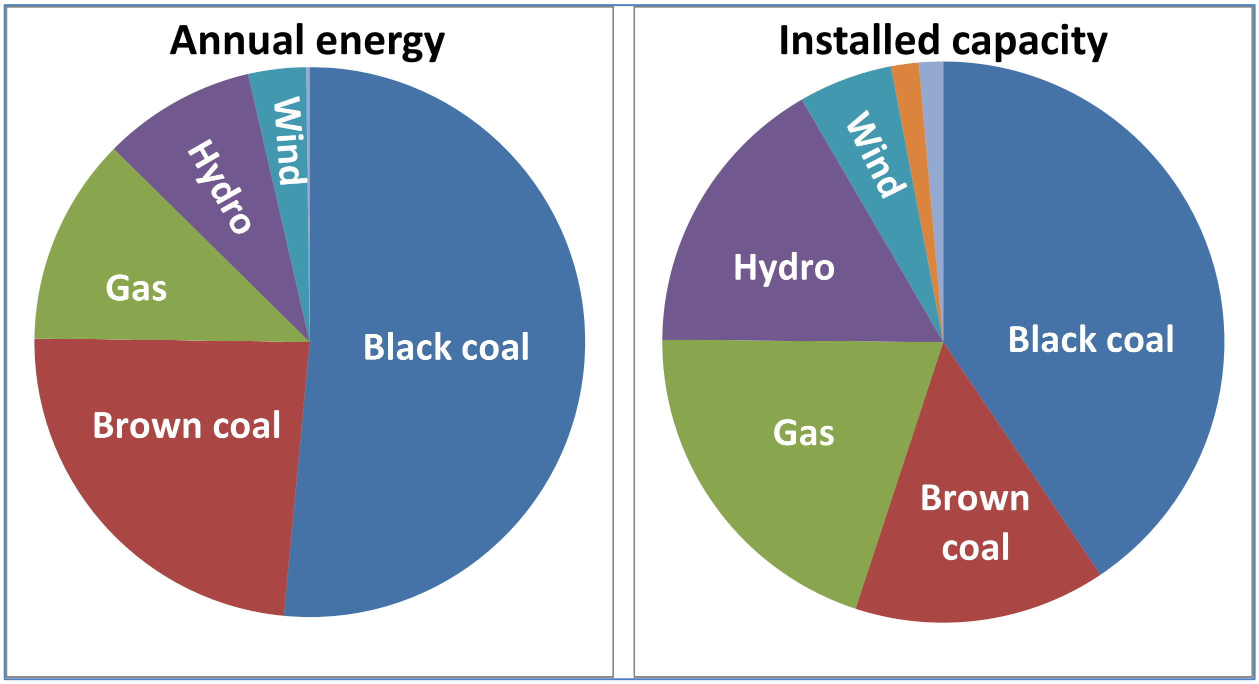


Figure 1 shows another aspect of the historical state-based development of the transmission system—the EHV transmission voltages used. Each region developed independently from its neighbors and selected the transmission voltages that best suited their needs. Queensland and South Australia use 275 kV, Victoria uses 220 kV with some 500 kV east and west of Melbourne, and New South Wales uses 330 kV with some 500 kV around the Sydney area. The result is that many interconnections between the regions require voltage transformation using power transformers. These transformers, besides being physically large and expensive, usually have thermal limits lower than the circuits they connect and introduce additional impedance into the overall transmission path. Both these factors significantly limit the capacity of the transmission interconnections between Regions.

1.2.3 NEM generating fuel sources

The dominant generation fuel source is coal (black and brown) as can be seen in Figure 2.[3] The figure shows both the relative shares by annual energy production and installed capacity. During the course of the year 75% of the electric energy was produced from coal; 20% from gas, 16% from water (hydro), 5% from wind, and 3% from other sources.

Figure 2: Generation production and capacity by fuel source



1.3 AEMO and SRAS

The objective for System Restart Ancillary Services (SRAS) is to minimize the expected economic costs to the market in the long term and, in the short term, the cost of any major supply disruptions that occur. This is consistent with the national electricity objective.[4] The AEMO must try to acquire SRAS that are consistent with the SRAS objective by entering into ancillary services agreements to provide “primary” restart services that satisfy the SRS and provide SRAS in each electrical sub-network. In the event that

3. As at 1 July 2013 for the 2012/13 financial year.
4. NER §3.11.4A and §11.2 describe the SRAS requirements and the AEMO’s role and requirements. NER §8.8 describe the role and requirements of the Reliability Panel.

adequate primary restart services are not available the Rules currently define a lower quality "secondary" SRAS as an option.

The SRS is determined by the Reliability Panel to meet the requirements of the NER. Specifically, the SRS must apply SRAS on a consistent basis across all regions, reflect any technical system limitations or requirements and identify the maximum amount of time that SRAS are allowed to take to restore a specified supply level target. In addition the SRS must include guidelines for the required reliability of primary and secondary restart services and specify their diversity and strategic locations. Finally, the SRS must include guidelines for the AEMO to determine electrical sub-networks including their appropriate number and the characteristics required (such as the amount of generation or load, or electrical distance between generation centers, within an electrical sub-network).

The AEMO must implement the SRS by:

- Developing and publishing a detailed description of each type of SRAS including whether the system restart ancillary service is a primary or secondary, the technical and availability requirements of each type of system restart ancillary service; and any other matter considered relevant by AEMO;
- Demonstrating that a facility is reasonably capable of delivering the relevant SRAS by modeling and assessing the technical capabilities of a proposed SRAS, physically testing SRAS, and any other analysis which AEMO considers appropriate; and
- Developing and publishing procedures for determining the number, type and location of SRAS required for each electrical sub-network.

Some of the specific requirements of the SRS include:

- Target times for restoration:
  - Within 90 minutes— auxiliaries should be energized for power stations capable of meeting 40% of the network's annual peak demand;
  - Within four hours—generation and transmission should be restored that could supply 40% of the network's annual peak demand;
- SRAS reliability:
  - Primary SRAS must be ≥90% reliable;[5]
  - Secondary SRAS must be ≥60% reliable;[5]

5. The SRS states that the AEMO will determine the how "reliability" will be determined.

- Electrical sub-networks boundaries should consider:
  - Number and strength of transmission corridors;
  - Electrical distance;
  - Amount of generation and load (≥1,000 MW).

1.3.1 AEMO assignment for DNV KEMA

In early September the AEMO engaged DNV KEMA to review certain aspects of the AEMO's responsibilities to procure SRAS under §3.11.4A of the NER. Specifically, DNV KEMA was asked to review:

1. Comment on the relative probability of a NEM-wide versus region-wide blackout, and the appropriateness of the proposal to procure SRAS to meet the system restart standard (SRS) from a region-wide, rather than a NEM-wide blackout;
2. Review and comment on AEMO's rationale for the definition of electrical sub-networks used for the purposes of procuring SRAS;
3. Review and comment on AEMO's proposed changes to the definition of SRAS;
4. Review and comment on AEMO's assessment of the quantity of SRAS (in addition to supplies from interconnected sub-networks where this is considered appropriate) required in each sub-network to enable the SRS to be met
5. Review the assumptions, basis and methodology for AEMO's modelling of the NEM system restart response
6. Compared with the likely performance of currently procured SRAS, review and comment on the impact of AEMO's proposed revised guidelines for the procurement of SRAS on:
   a. Meeting the SRS;
   b. The subsequent restoration of load in each sub-network (over and above the SRS of 40% restored within 4 hours); and
   c. Overall achievement of the System Restart Objective as set out in §3.11.4A(a) of the NER.
7. As an option, compare the SRS for the NEM with other similar requirements internationally

1.3.2 Proposed changes addressed by DNV KEMA

The seven issues being reviewed here by DNV KEMA (see §1.3.1, above) fall into three major areas:

1. The probability of the assumed blackout condition—NEM-wide versus state-wide;
2. The number of sub-networks and SRASs in each

3. The SRAS definition, quantity and assessment

The changes being proposed by the AEMO are summarized in Table 5. DNV KEMA's review of each of these is addressed in the following chapters.

Table 5: Proposed changes being addressed by DNV KEMA

Subject	Now			Proposed		
Assumed blackout condition	NEM-wide			Region-wide		
Sub-networks						
Number of SRAS per sub-network	Generally two per sub-network			Generally one per sub-network		
	Sub-network	SRAS/sub-network	SRAS/ region	Sub-network	SRAS/sub-network	SRAS/ region
Queensland	3	2	6	2	1	2
New South Wales	2	2	5	2	1	2
Victoria	2	2	4	1	1	1
South Australia	1	3	3	1	1	1
Tasmania	2	2*	3	1	2	2
Total	10		21	7		8
SRAS definition	Primary and secondary			Only one definition		
	Focus on SRAS rapidly energizing auxiliary supply bus of large generating units			Focus on rapidly delivering SRAS power to the transmission system		

Note: * There is only one SRAS resource in the northern Queensland sub-network and there are three in Tasmania.

DNV KEMA prepared this report by reviewing a wide range of publicly-available documents and selected confidential documents, discussing various aspects of the NEM electric system with AEMO staff, and our past international experience and engineering judgment. No technical analyses were made other than those described in this report.

2. Blackout probability—NEM-wide versus state-wide

The AEMO now applies the underlying assumption that a NEM-wide blackout occurs in determining SRAS. With this assumption, each region must provide enough SRAS resources to restart their individual systems. At some point, systems would be able to re-establish their interconnections allowing the states to assist each other.

There is no requirement in the NER or SRS to assume such a NEM-wide blackout for determining SRAS.[6] For the years before the Australian electricity systems were deregulated and the NEM formed, the electric systems were planned and operated as individual state systems. Each state assumed a region-wide blackout in determining their black-start needs.

In a NEM-wide blackout it would likely be several hours before neighboring systems could assist their neighbors in the restart process. With a regional blackout, on the other hand, neighboring systems should be available to assist in the restart process in a matter of minutes. This difference is the main change being proposed by the AEMO—that neighboring systems will be the primary restart source following a regional blackout.

2.1 The AEMO's position

In their *System Restart Ancillary Services–Draft Report* the AEMO proposes assuming regional blackouts as the basis for determining SRAS requirements. [7] The AEMO currently assumes the existence of a NEM-wide black system condition, although the SRS and the NER do not require this assumption. The AEMO believes that assuming a NEM-wide blackout is "too conservative" and "highly unlikely" and that the present approach provides a higher coverage level than required and is not economically justified.

The AEMO continues by noting that:

- In the event of a major disturbance the national grid is very likely to separate at the weak points; the regional boundaries;
- The NEM has not experience a system-wide (or even a region-wide) outage following some recent major events:
  - The major loss of generation in New South Wales in 2009,
  - Major bushfires in New South Wales, Victoria and Tasmania, or
  - The 2012 earthquake in Victoria.

6. The AEMO discussed this issue in its *System Restart Ancillary Services Review—Issues and Options Paper*, 25 January 2013, and *System Restart Ancillary Services Review—Draft Report*, 10 May 2013.
7. *System Restart Ancillary Services–Draft Report*, AEMO, 10 May 2013, §6.2.1.

- Region-wide blackout conditions were the standard before deregulation; and
- If a NEM-wide blackout were to occur in the future, however unlikely, the system could still be restored, but restoration might take longer with new SRAS approach.

2.2 Lessons from other blackouts

There are as many different causes of blackouts as there are blackouts—each is somewhat unique. There are, however, several common patterns that can be seen in blackouts. At the highest level, there are two major categories—controlled and uncontrolled blackouts.

2.2.1 Controlled blackouts

In a controlled blackout system operators (or automated control devices) actively disconnect loads to prevent a larger blackout. Such a situation can occur, for instance, when there is a fuel shortage that reduces the total or regional system generating capacity. System operators disconnect customer load to maintain a balance between load and generation. Automated load shedding can occur following a large scale generation outage that causes a sudden drop in system frequency, in order to restore the load and generation balance and stabilize frequency. Controlled blackouts may last for hours but only part of customer load is out of service at any time and the outages are rotated among customers so that they are only out part of the time. While controlled blackouts are a problem, they generally allow the public to be notified about the expected duration and are much less disruptive than uncontrolled blackouts.

2.2.2 Uncontrolled blackouts

Uncontrolled blackouts occur unexpectedly and are usually what the public means when they discuss blackouts. All uncontrolled blackouts begin with an unplanned system “event” that causes a sudden change in the load-generation balance—usually when a large amount of generation is suddenly lost—at least within one or more areas of the system. This imbalance can be triggered by a large loss of generation or by a major transmission system interruption. This imbalance has immediate effects on system generation and transmission.

The remaining generation will try to restore the generation-load balance by automatically changing its output. If there is enough generating capacity still running and available to make up for the generation lost then the system should recover. If there is not enough generation running to make up for the lost generation, the system frequency will start to decline. Once the frequency falls far enough the automatic under-frequency load shedding (UFLS) system should disconnect enough load to restore the balance between generation and load. If balance is restored, the loss of load is considered a controlled event. If the operation of UFLS fails to restore the balance between generation and load in all areas—an uncontrolled system blackout can result. In some cases an unplanned event can trigger a system voltage collapse that leads to a blackout, without a sufficient drop in frequency to activate the operation of UFLS.

The uncontrolled major system blackouts that have occurred around the world usually happened because there was not enough transmission to maintain the necessary connections between load and generation, or because there were inadequate resources to support system voltage. In uncontrolled blackouts the system conditions typically change too rapidly for human response, so automatic protection devices installed in the system will rapidly disconnect generation units and transmission system equipment because of:

- Excessive equipment loading;
- Extremely low or high equipment voltages or system frequency; or
- Generator speed, frequency, power flow and/or voltage conditions that well outside normal operating conditions.

As this equipment is disconnected by protective devices, loading conditions change further on the remaining energized parts of the system, leading to further disconnections. This phenomenon is commonly called a "cascading outage".

2.3 Interconnections limit blackout propagation

A cascading outage usually continues until it reaches a transmission break point—often the interconnection between adjacent regions or systems. Such break points are reached when there is not enough transmission capacity connecting the "problem area" with the remaining portions of the system. In most cases this will stop the cascade process by isolating the problem area from the rest of the system.

2.3.1 North American blackout example

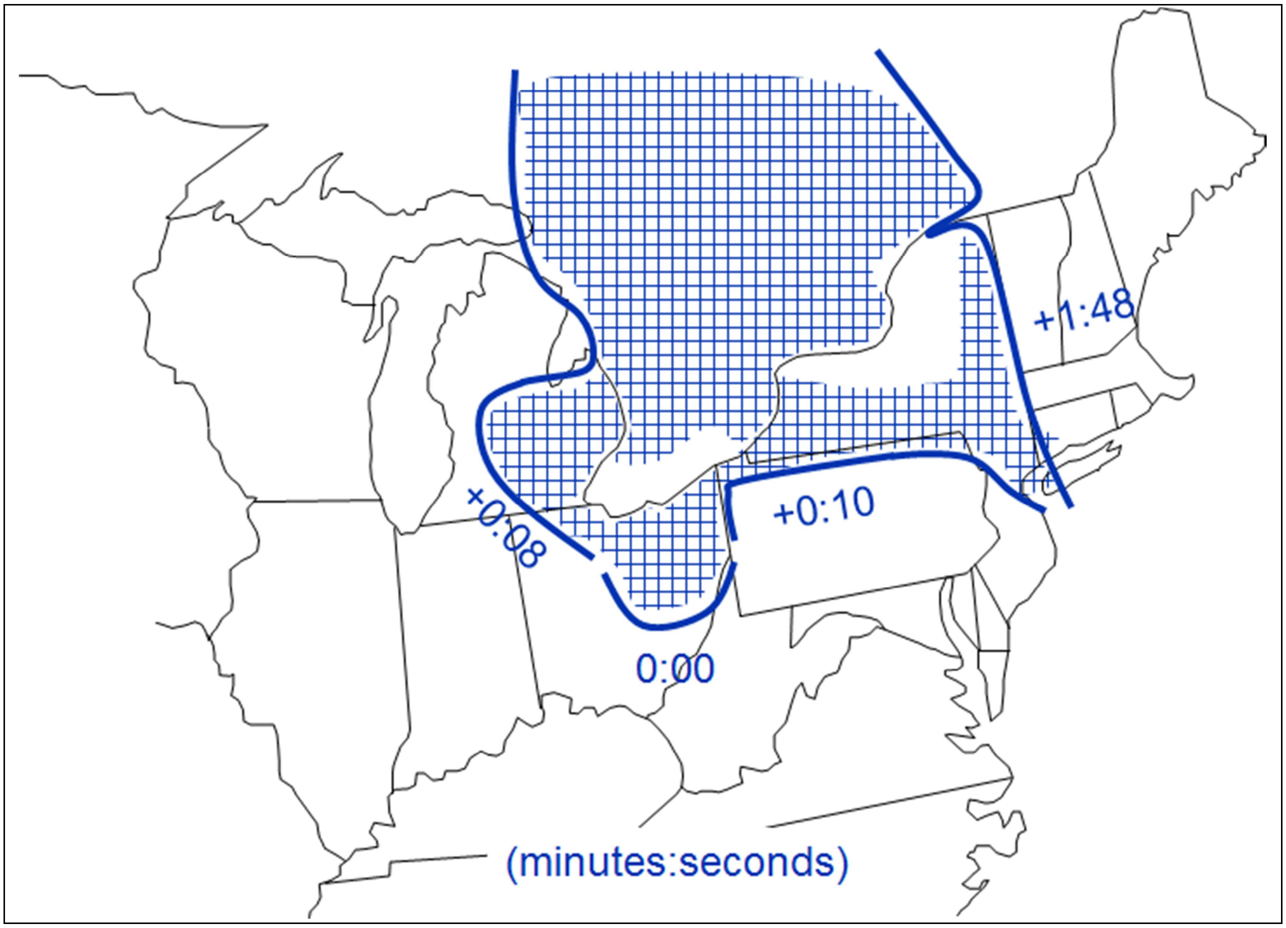
The 2003 US/Canada blackout demonstrated all these conditions. The entire eastern US/Canadian system normally operates as a synchronous interconnected system. Figure 3 shows the sequence of transmission separation that occurred during the August 2003 blackout. The blacked-out area was initially importing nearly 3,000 MW before the blackout.

The event started with overloaded lines that tripped along the corridor labeled time 0:00 (minutes: seconds). Most of the cascading separations occur in the next 10 seconds. The tripping at time +0:08 occurred because of low voltages (below 85%) in the area. At time +0:10 transmission lines tripped from thermal overloading (2,800 MW). At time +1.48 the blackout area was completely isolated when electrical synchronism was lost between generators in the two neighboring portions of the grid.

This blackout demonstrates that blackouts cascade until they reach a transmission break point. In the 2003 US/Canada blackout there were three major transmission corridor break points as shown in Figure 3. This is a typical pattern for cascading blackouts in large systems around the world.

This general pattern—that cascading outages propagate until they reach a natural transmission break point in the system—has been true for all large system blackouts.[8]

Figure 3: Timing of US/Canada 2003 blackout transmission events



2.3.2 Transmission break points in the NEM

Based on a review of the NEM transmission system maps and the locations of load and generation, and relying on engineering judgment, several likely transmission break points were identified.[9]

In this review we identified transmission break points considering three factors from the SRS:

1. The number and strength of transmission corridors;
2. The amount of generation and load in an area; and

8. There have many blackouts in smaller, isolated systems that have no real transmission break points.
9. Powerflow analysis and other technical studies would be needed to confirm these predicted break points, but are beyond the current scope of work.

3. The electrical distance between load/generation centers.

In particular, the strength of transmission corridors was determined using a transmission “cut-plane” approach. The cut-plane approach we used counted the number and voltage levels of the lines that could separate two areas in the transmission system. More circuits and higher voltages indicate higher transmission corridor capability. The goal was to find corridors that had less capability than other nearby possibilities.

In the following sections we discuss our findings related to transmission break points and the existing sub-network boundaries used for SRAS process. We note that the existing sub-network boundaries are based on historical/political factors and were not determined based on the natural transmission break points. We discuss sub-networks and their boundaries in Chapter 3, below.

2.3.2.1 Queensland

There appear to be two transmission break points in Queensland one in the center of the state north of Brisbane, and one in the area bordering New South Wales.

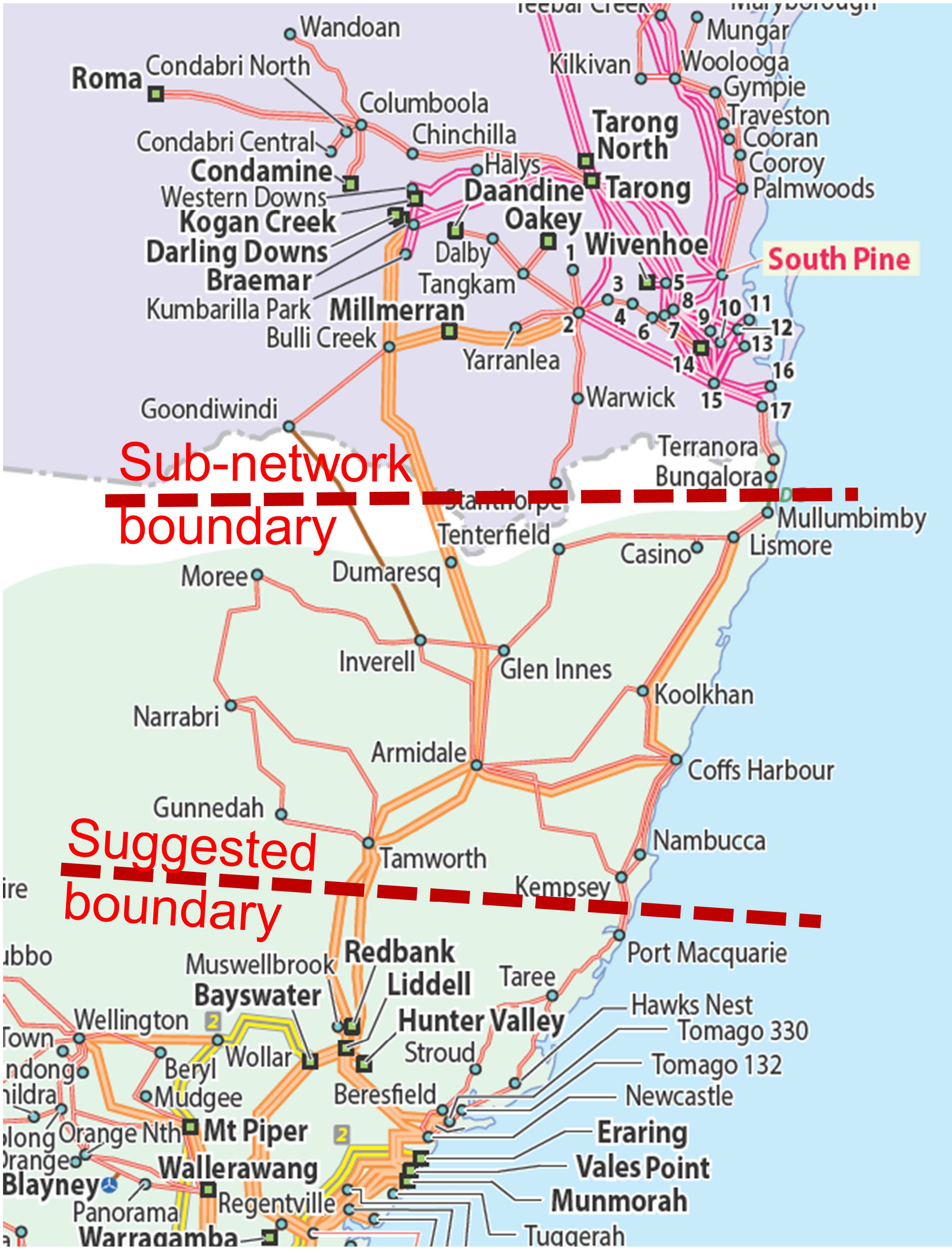
The central Queensland break point will likely lie along the existing sub-network boundary between south and central Queensland, as shown in Figure 4. This break point includes five 275 kV circuits with about 4,500 MW of generation just to the north from the Gladstone, Stanwell and Callide power plants. The central-Queensland break point might also lie along the slightly electrically weaker suggested boundary shown in Figure 4 with four 275 kV circuits. Both break points include the Tarong–Calvale 330 kV circuits; the difference between these two break points is where a break would occur along the eastern 275 kV path.

Figure 4: Central Queensland transmission break point

The southern Queensland break point is more uncertain and interesting. The current sub-network boundary lies along the inter-state border between Queensland and New South Wales as shown in Figure 5. The break point includes two 330 kV AC circuits and one HVDC circuit.

We believe that the break would more likely occur farther south along the suggested boundary shown in Figure 5. The suggested boundary also includes two 330 kV circuits but the third circuit is at 132 kV. In addition, there is a kind of transmission loop between Armidale and Coffs Harbour in the south and Millmerran and the Brisbane area in the north. This transmission loop is likely to remain intact following a serious disturbance with the break point to the south as shown.

Figure 5: South Queensland transmission break point



2.3.2.2 New South Wales

New South Wales is now divided into two sub-networks along the sub-network boundary as shown in Figure 6. However, this is not a likely transmission break point as we have defined it in this review. The system is very unlikely to split along the existing sub-network boundary as it is so electrically strong—it includes four 500 kV and six 330 kV circuits. The sub-network boundary also splits the transmission loop just north of Sydney that includes about 13,000 MW of generation.

Figure 6: New South Wales transmission break point

The suggested boundary is the same as shown in the discussion of Queensland. This suggested break point includes two 330 kV and one lower voltage circuit. We believe the system is much more likely to split along the suggested boundary than the existing sub-network boundary.

2.3.2.3 Victoria

Victoria includes one sub-network boundary and boundaries with New South Wales and South Australia as shown in Figure 7.[10] The interstate boundaries with New South Wales and South Australia are both transmission break points. We believe there are no break points within Victoria.

Figure 7: Victoria transmission break points

The Victoria–New South Wales boundary includes three 330 kV and one 220 kV circuits. Possible cut-planes both north and south of this boundary include much more transmission capability, so it is likely to be the break point between these two states.

The Victoria–South Australia boundary includes two 275 kV circuits and an HVDC circuit. The transmission break point is likely to be slightly different in that the break between these two states would probably occur at the 500/275 kV transformers at Heywood that have lower ratings than the 275 kV circuits. This difference is rather technical because the systems would split between the Heywood 500 kV and the South East 275 kV substations with either definition.

10. There is also a boundary with Tasmania using an HVDC circuit.

The existing Victoria internal sub-network boundary has been set to meet the SRS requirement that there must be at least 1,000 MW of load and generation in any sub-network. In our review of the Victoria network we see no internal transmission break points. The system appears to have three areas. The first area is the highly dense load and generation area from Heywood in the west through Melbourne and to the Latrobe Valley in the east. This is a tightly integrated network with multiple strong transmission circuits connecting the load and generation in the area.

The second is the transmission network that connects Melbourne with New South Wales. This provides a strong connection to the border area with New South Wales where we believe a transmission break point now exists.

The third area is the area northwest of Melbourne. There might seem to be a break point between the Ballarat and Shepparton 275 kV substations and the Heywood–Melbourne–Latrobe area to the southeast. There is only light customer load and very little generation in this area so the transmission network is likely strong enough remain intact and not represent a break point.

2.3.2.4 South Australia

South Australia is now treated as a single network as shown in Figure 8. South Australia is interconnected with Victoria through a 500/275 kV interconnection to Heywood and an HVDC connection to Red Cliffs. There is no obvious internal transmission break point. We agree with the AEMO—there is no need for two sub-networks in South Australia.

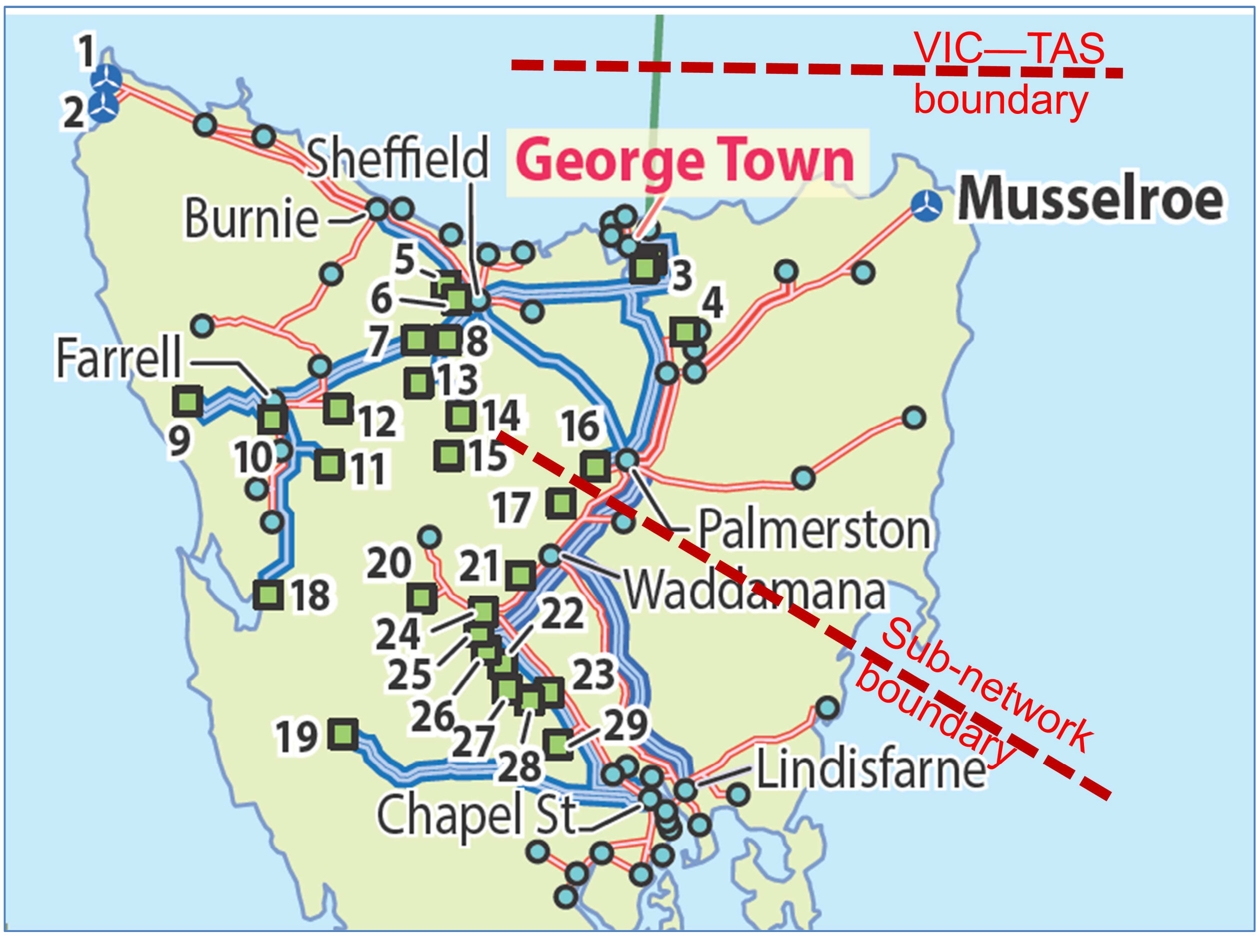
Figure 8: South Australia transmission network

2.3.2.5 Tasmania

Tasmania is now divided into two sub-networks as shown in Figure 9 and it also has the HVDC connection with Victoria. The existing sub-network boundary includes two 220 kV and one 110 kV circuits between Palmerston and Waddamana. The customer load is almost evenly split between the two sub-networks with about 900 MW in each. There is about 2,000 MW of generation in the north and a 1,000 MW in the south. The generation in Tasmania is almost all hydro-electric that has similar operating costs.

While the sub-network boundary could be considered a transmission break point, the relative load and generation must also be considered. There appears to be enough transmission capacity in the three circuits that they could support more than 40% of the 900 MW of load on either side of the boundary. We believe there is no need for two sub-networks in Tasmania as there is no likely transmission split point.

Figure 9: Tasmania transmission break points



2.4 Loss of largest plant in each region—impact on interconnections

To examine the possible impact of a large generation outage event on interstate transmission corridors the impact of losing the largest generating plant in each region was estimated. During the first few seconds following a generation outage the system frequency will drop as the “missing” power is supplied by the rotating inertia of all the other interconnected generators. The impact of the initial power surge that occurs from the rotating inertia of the operating generating plants was estimated based on the share of generation in each state. In this way, installed capacity was a substitute for rotating inertia.[11]

This inertial generation response typically lasts just a few seconds as the system slows to a new balanced operating state. If the amount of generation lost is high enough, the frequency would fall enough to trigger UFLS systems in some or all of the interconnected systems.

11. This is a fairly simplified approach. Not all installed generators will be operating at given time and different generators have different rotating inertias.

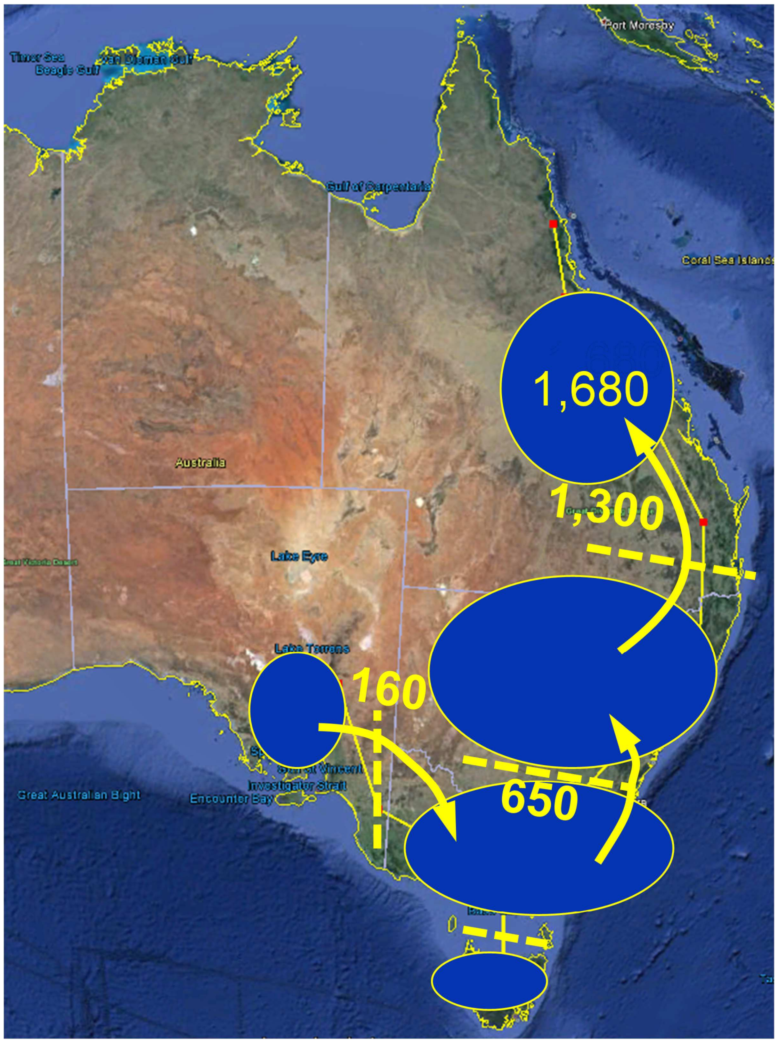
2.4.1 Queensland

Gladstone is the largest plant in Queensland with 1,680 MW of capacity (6 x 280 MW units). Following the sudden loss of this entire plant, generation within Queensland would supply about 380 MW of the loss. The remaining 1,300 MW would be supplied from the other regions as shown in Figure 10.[12]

The NSW to QLD transmission limit is always less than 700 MW. The 1,300 MW flow shown is much greater than this limit. The limit is not based on thermal capability since the QLD to NSW limit is 1,200 MW.

None of the other interstate flows seem to be high enough to trip any interconnections as they are well below their normal ratings. We believe that only Queensland might disconnect from the rest of the NEM system for such an event.

Figure 10: Interstate transmission flows following loss of largest Queensland power plant



12. Some support would also come from Tasmania through the HVDC connection; however, the amount would be determined by the the HVDC control system and not be directly related to plant inertia.

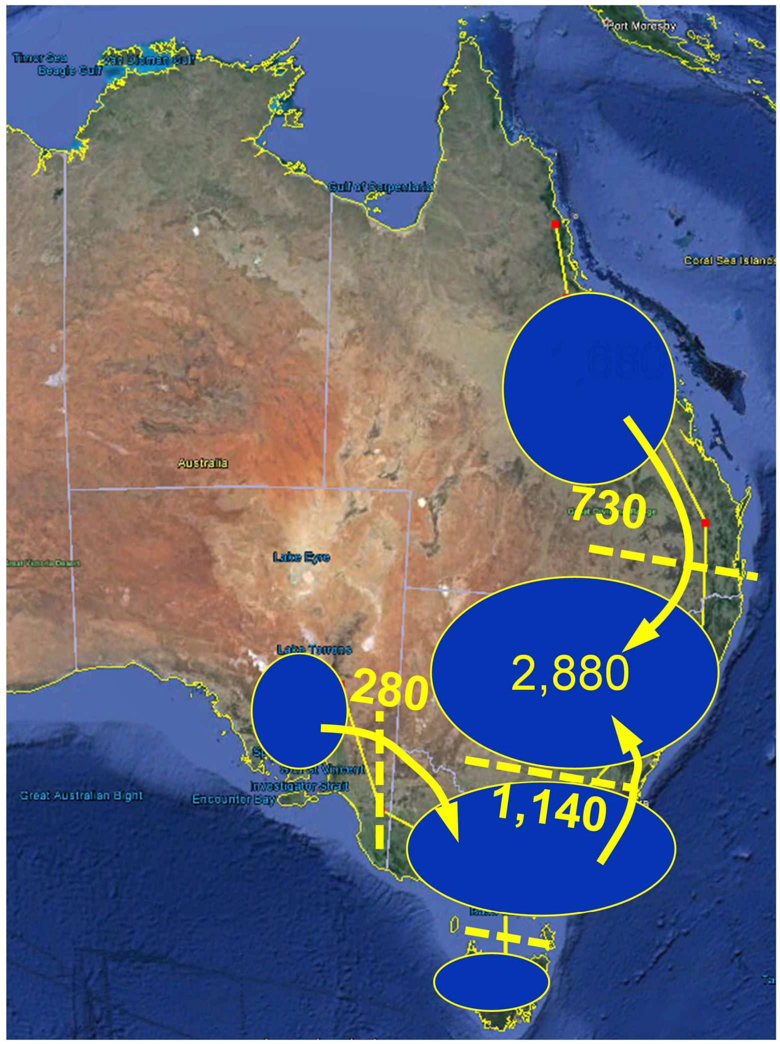
2.4.2 New South Wales

Eraring is the largest plant in New South Wales with 2,880 MW of capacity (4 x 720 MW units). Following the sudden loss of this entire plant, generation within New South Wales would supply about 1,010 MW of the loss. The remaining 1,870 MW would be supplied from the other regions as shown in Figure 10.[13]

None of the interstate flows seem to be high enough to trip any interconnections as they are well below their normal ratings. We believe that all the interconnections would remain in service following this outage.

It is possible that pre-fault interstate flows would be high enough and in the right directions that some interconnections would open and isolate New South Wales.

Figure 11: Interstate transmission flows following loss of largest New South Wales power plant



13. Some support would also come from Tasmania through the HVDC connection; however, the amount would be determined by the the HVDC control system and not be directly related to plant inertia.

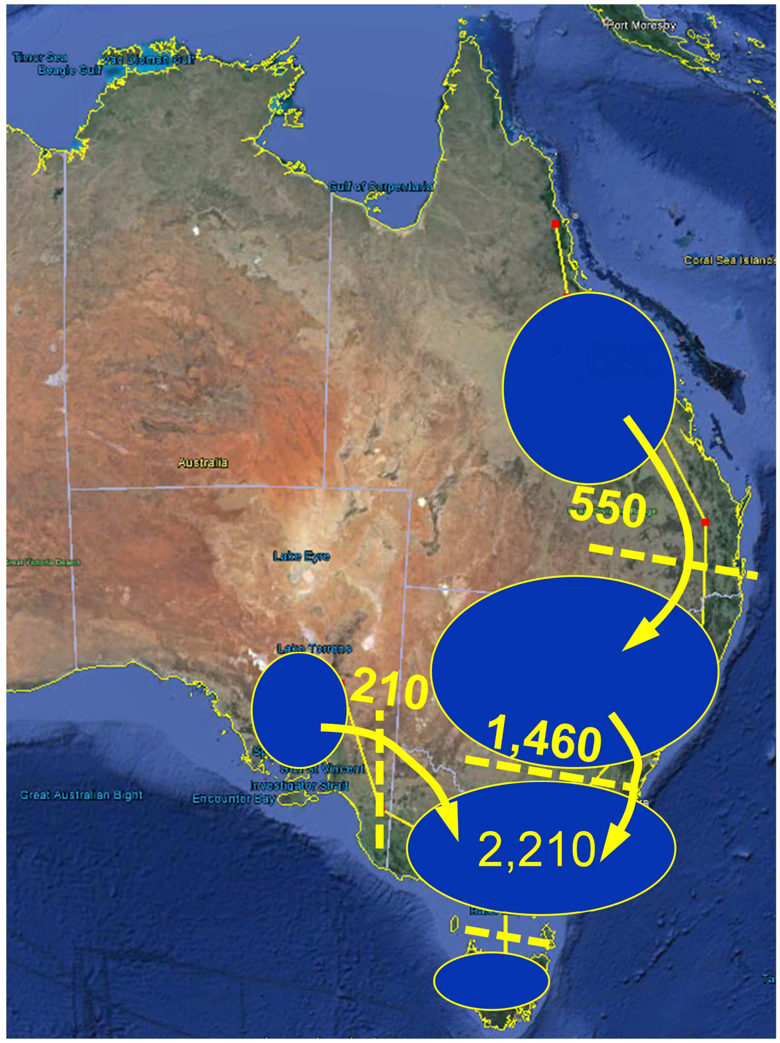
2.4.3 Victoria

Loy Yang A is the largest plant in Victoria with 2,210 MW of capacity (3 x 560 MW units and a 530 MW unit). Following the sudden loss of this entire plant, generation within Victoria would supply about 540 MW of the loss. The remaining 1,670 MW would be supplied from the other regions as shown in Figure 10.[14]

None of the interstate flows seem to be high enough to trip any interconnections as they are well below their normal ratings. We believe that all the interconnections would remain in service following this outage.

It is possible that pre-fault interstate flows would be high enough and in the right directions that some interconnections would open and isolate Victoria.

Figure 12: Interstate transmission flows following loss of largest Victoria power plant



14. Some support would also come from Tasmania through the HVDC connection; however, the amount would be determined by the the HVDC control system and not be directly related to plant inertia.

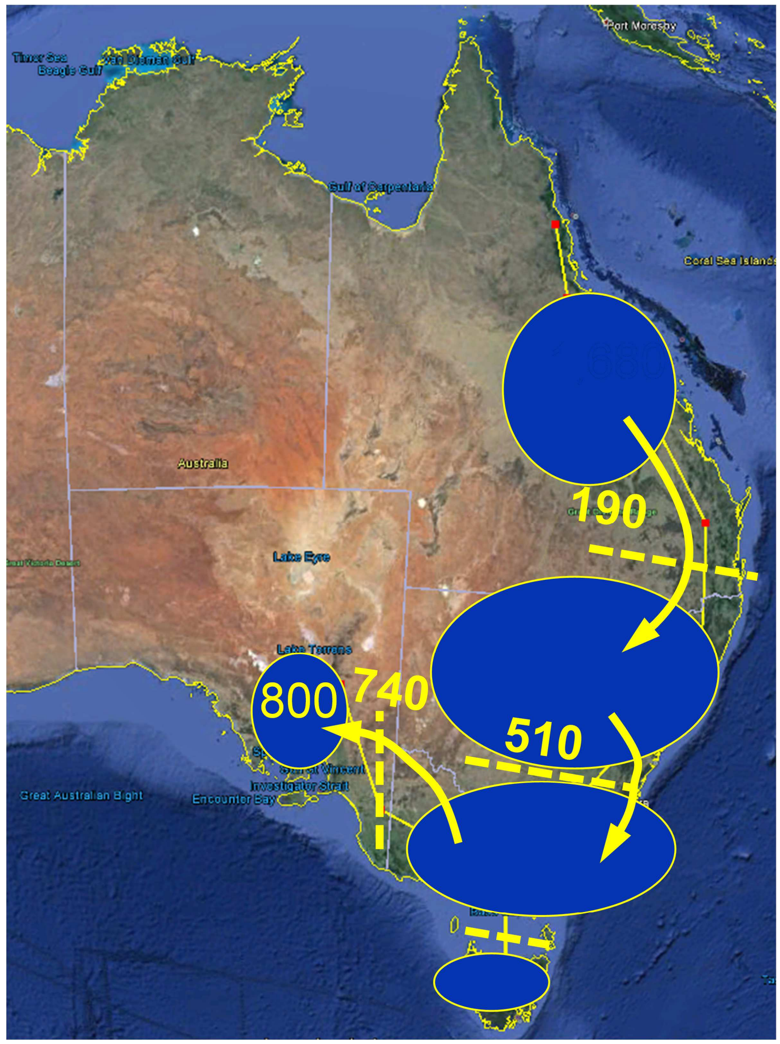
2.4.4 South Australia

Torrens Island B is the largest plant in South Australia with 800 MW of capacity (4 x 200 MW units). Following the sudden loss of this entire plant, generation within South Australia would supply about 60 MW of the loss. The remaining 740 MW would be supplied from the other regions as shown in Figure 10.[15]

The 740 MW flow from Victoria is more than the normal interconnection capability of 680 MW (460 MW for the AC lines and 220 MW from the HVDC line) and the interconnection would trip and isolate South Australia.

None of the other interstate flows seem to be high enough to trip any interconnections as they are well below their normal ratings. We believe that all the other interconnections would remain in service following this outage.

Figure 13: Interstate transmission flows following loss of largest South Australia power plant



2.5 NEM-wide versus region-wide probabilities

As discussed above, perhaps the primary change being suggested by the AEMO is to change the assumed basis for SRAS is from a NEM-wide outage to region-wide outages. The effect of this change is to reduce the amount of SRAS needed to meet the SRS as discussed elsewhere in this report.

15. Some support would also come from Tasmania through the HVDC connection; however, the amount would be determined by the the HVDC control system and not be directly related to plant inertia.

There are two broad aspects in comparing the probabilities of a NEM-wide versus region-wide blackout: the probability of the triggering event and the extent of the impact of the triggering event. In considering triggering events we assume that the system is planned and operated to a single-contingency “n-1” standard; where any individual element in the bulk power system can be lost without interrupting customer load. We also assume that there are various other, more-severe events, that would not cause cascading outages due to automated actions by UFLS, special protection systems or other preplanned mitigating measures.

2.5.1 Event probability and extent

There are many possible events that could trigger a blackout. They range from an equipment failure to natural disasters or deliberate attacks.

We group the possible trigger events into three categories:

1. Accidental;
2. Natural disasters; and
3. Deliberate attacks.

The probabilities and extent of various possible triggering events are summarized in Table 6. Each is discussed in the following sections.

Table 6: Blackout-triggering events, probabilities and extents

		Extent	
Event	**Probability**	**Equipment/system**	**Geographic**
Accidental			
Substation errors/faults	Moderate	Substation	Partial network
Fuel supply disruption	Low	Generation	Partial network
System operator misoperation	Low	Gen & trans	Partial network
Misoperation	Very low	Cascade	State
Natural disasters			
Tornado	Moderate	Transmission	Partial network
Flood	Moderate	Gen & trans	Partial network
Fire	Moderate	Transmission	Partial network
Earthquake	Low	Gen & trans	Sub-network
Cyclone	Moderate	Transmission	Partial network
Geomagnetic storm	Very low	Gen & trans	Multiple networks

Event	Probability	Extent	
		Equipment/system	Geographic
Deliberate attacks			
Physical attack			
Single site-transmission	High	Trans	Local
Single site-generation	Very low	Gen & trans	Local
Coordinated multiple sites	Extremely low	Gen & trans	State/partial network
Cyber attack			
Generation	Very low	Generation	Local
Transmission	Very low	Transmission	State/partial network
Fuel supply	Very low	Generation	Partial network
State dispatch center	Extremely low	Gen & trans	State
National dispatch center	Extremely low	Gen & trans	Scattered local

2.5.1.1 Accidental trigger events

There is a wide range of accidents that can trigger small system outages from utility field crew errors to traffic accidents and equipment failures that affect individual transmission structures. Such accidents, while common, have very limited impacts on the power system and its customers. We must consider a class of larger accidents that could cause widespread outages.

Substation accidents

Substation accidents and equipment failures that might damage substation equipment occur on all systems. They range from damaged breakers to fires or collapsing cranes. This category often involves errors/accidents during construction or maintenance. There have been some catastrophic transformer fires in the western US that have resulted in major local system disturbances, but to cause a significant blackout the accident generally must affect facilities beyond any one substation.

Misoperation and maintenance errors can cause serious problems, but even serious ones do not cause large cascading outages. One example occurred in San Francisco in 1998 while substation maintenance was being completed. System operators closed breakers in the substation into a solid three-phase fault. Since the normal protection system was disabled during maintenance none of the breakers in the substation operated. This meant that breakers operated at the remote ends of all five of the 115 kV circuits connected at the substation. The result was the loss of about 370,000 customers and 600 MW of load.

Since such incidents occur at utilities around the world all too regularly we estimate the probability as moderate. A significant substation accident would likely result in a customer outage (blackout) that would be limited to a portion of a sub-network or region.

Fuel supply accidents

Fuel supply accidents and disruptions can and do occur. The fuels used in the NEM are coal, natural gas and water. Electric generation in the NEM by fuel source is shown in Figure 2 on page 18, above. The possible disruption causes would be different for each. We believe that only natural gas supply accidents/disruptions might cause some limited uncontrolled customer outages within a region.

Coal plants have at least several days fuel supply stored on-site so strikes by coal miners or rail suppliers would not cause immediate electric supply problems. While such actions would, no doubt, disrupt the normal operation of the electric system and the power market. There would be time for system operators to plan to make of the best of whatever supplies remained and take steps to prevent any uncontrolled system outages.

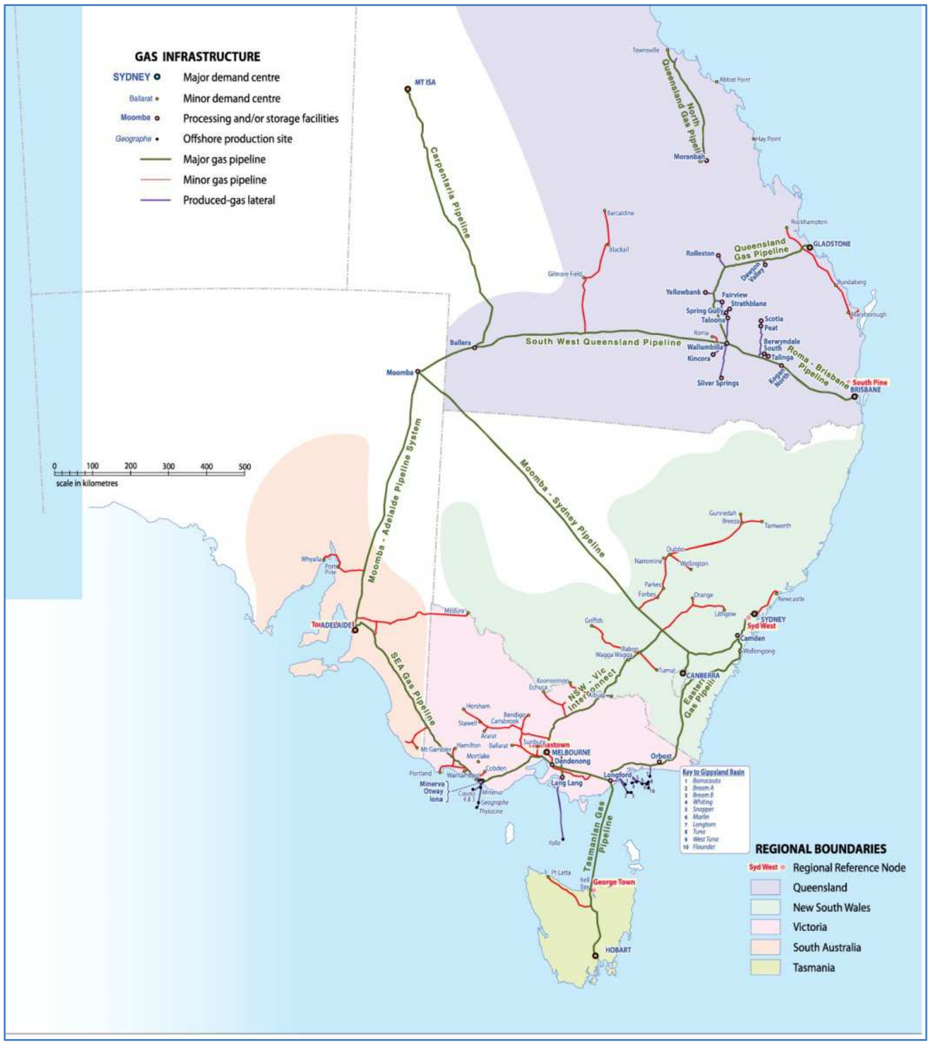
It is possible that a fire or explosion could damage the supply at any one coal or gas power plant, but this should not cause wide-spread electricity outages. Losing an entire power plant would also disrupt power supplies and, if the plant were large enough, it would trigger UFLS and perhaps some uncontrolled local outages in a region.

Hydro-electric power plants, as with coal, have on-site fuel reserves. A prolonged drought would reduce fuel supplies to a region (especially Tasmania) but would occur over a period of years and would not cause a sudden disruption. It is conceivable that an earthquake could cause sudden major damage to multiple hydro-electric power plants; such an earthquake would also likely severely damage customer facilities and infrastructure. Even in Tasmania, a state that is wholly dependent on hydro-electric generation, there would certainly be some undamaged power plants.

Natural gas supply disruptions, unlike coal or hydro-electric power, have the potential to cause sudden electric supply outages. Gas pipeline accidents and explosions occur from time to time. Natural gas supply disruptions will, obviously, affect gas-fueled power plants (and other natural gas users). There is at least one mitigating factor—the gas pipeline network provides some stored gas so that some generating plants will be able to operate for at least a few minutes following a gas accident.

The NEM gas pipeline network map in Figure 14 shows three regional networks—in southern Queensland, New South Wales and Victoria—that are interconnected by long pipelines. There are smaller gas pipeline networks in South Australia and Tasmania. And, there is also a small isolated network in north Queensland.

Figure 14: NEM natural gas pipeline network



There are places on the gas network that might cause serious disruptions but none that could cause a sudden NEM-wide gas supply disruption. The disruption would have to suddenly affect electric generation because even as little as a ten minute delay would allow system operators to take action to mitigate the problem.

As with the electric transmission network the gas pipeline network has limited connections between the regions.

Misoperation accidents

Misoperation is a catchall group for various human actions or equipment malfunctions. We believe that human errors are more likely to have a wider impact than any equipment failure. The most serious misoperations would likely occur at the regional operating centers. It would be at these centers where an error could affect multiple generating units or transmission facilities. Such misoperation would have to be fairly extensive—affecting multiple transmission elements and/or generating units.

2.5.1.2 Natural disaster triggering events

Australia has experienced all the natural disasters listed in Table 6, above—floods, fires, earthquakes, and geomagnetic storms. All of these are serious events that can disrupt the electric system. Each of them will have limited geographic scope, however.

Tornados

Tornados are perhaps the most concentrated of these disruptions in that they inflict serious damage along their path. While a tornado cana destroy transmission circuits along their path as well as substations and power plants, there most serious impact is likely to be to the transmission network. We believe there is no path in the NEM system that will cause more than a regional electric outage. If a tornado were to cause a major blackout it would be limited to the affected region because of the limited inter-regional transmission facilities.

Fires and floods

Bush fires are fairly common in the NEM region and are especially threatening to transmission lines. Similarly floods can threaten power plants and transmission substations. Either threat is serious but would be limited in its geographic scope.

Cyclones

Cyclones and geomagnetic storms can affect wide geographic areas. Cyclones include elements of flooding besides the damage caused by their high winds. We believe cyclone damage will be concentrated in the transmission system where the conductors and towers can be damaged. There is usually an offsetting effect with major cyclones in that, while they damage the electric system, they also damage customer load. Thus, customer load will also be reduced at the same time that the power system is damaged.

Geomagnetic storms

Geomagnetic storms can also affect a wide area of the electric system. Due to the nature of the earth's magnetosphere, systems at higher latitudes are most susceptible. In the NEM this means that Victoria, Tasmania, South Australia and, perhaps, the southern portion of New South Wales are at greatest risk. There is a potential for transmission disruptions over a widespread area.

Geomagnetic storms affect long overhead transmission lines most. There are only a limited number of such lines. There are several long 220 kV lines in New South Wales connecting Broken Hill, Buronga, Balranad, and Colleambally. Red Cliffs. There are several long 220 kV lines in Victoria connecting Red Ciffs, Horsham, Ballarat, Wemen, Kerang, Bendingo, and Shepparton. There is also a long double circuit line connecting Tailem Bend with South East in South Australia. Events on any and all of these circuits will cause local outages but should not cause wider outages.

2.5.1.3 Deliberate attack events

Physical attacks

Electric power systems have been subjected to physical attacks for many decades. Transmission line insulators have been used for random target practice as well as the occasional eco-terrorist or disgruntled/disturbed individual. These rarely have any significant impact on electric supply.

Transmission lines, substations and power plants are recognized targets for military action at least since World War II. They are also known targets for other organized groups.

Transmission lines are perhaps the easiest targets as they are remote and unattended allowing easy access and little chance of detection. Attacks on any one or two transmission lines are not likely to cause more than local customer outages.

Transmission substations are also targets. Damaging most substations, however, will usually blackout only local customers loads. There are a handful of critical or very large substations that could blackout part of a state but with no cascading outside a limited area. We note that such an attack could significantly impact the operation of the power market raising the cost of energy and likely making system operation more difficult.

An attack on a power plant could easily increase generating costs and cause a blackout limited to a portion of a state. In §2.4 beginning on page 35, above, we estimated the impact of the complete loss of the largest power plant in each state. The section demonstrated that while these events would be serious outages they would not result in any blackouts beyond a single state.

It is possible that a coordinated attack on multiple sites could cause a regional/state blackout. Such an attack would need to strike multiple sites that had been selected for effect. Such an attack would require advanced knowledge of power systems and the Australian network. It would also require careful coordination of a team of agents across a state. We believe this to be an extremely unlikely event, and we note that widespread measures have been adopted in recent years in North America to limit unauthorized access to power system maps, studies and other documents that could be used for planning such attacks.

Cyber attacks

Cyber-attacks are a potentially serious matter. The idea is in vogue with the general public and the source of frequent discussion in the electric power industry. In power systems there could be specific equipment attacks or attacks on systems. There could also be a general attack such as a distributed denial-of-service attack.

There are two aspects of power systems that significantly reduce the possible impact of a cyber-attack on power systems. The first regards equipment. Much like PC operating systems such as Windows, Linux or Mac OS, an attack must be specifically designed to attack that system. An attack designed for a General Electric product would not affect a Siemens device. And an attack that targeted a specific model would probably not affect another model of the same device by the same manufacturer.

The second aspect of power systems that reduces the potential impact of a cyber-attack is the lack of connectivity to the public internet. The AEMO and the Australian Transmission Network System Providers (TNSPs) do not connect their operating networks with their business networks. This means that to attack the power system an agent would need to gain access to a utility facility either directly or through trickery.

An example of direct access would be through a substation control room to gain access to the utility's private network. A very knowledgeable person could devise a program that could attack specific equipment. They would have to know about the specific communication facility and the specific equipment used by the utility.

Trickery could be used to get an employee to introduce a virus into a critical system. A virus planted on an employee's USB drive could be connected to the private network at operating center and introduce a virus.

A cyber-attack on a generator, transmission substation, or fuel supply would be very unlikely and would have a limited effect on the system. A direct physical attack, however, would be almost as effective and require much less sophistication.

A cyber-attack directed at the AEMO national dispatch center would have no serious affect. The AEMO center does not have direct control over any transmission or generation facilities and all instructions are given verbally. Perhaps a virus could be configured to send erroneous information that might confuse the AEMO operators but would not threaten system operation.

The remaining vulnerable targets are the regional operating centers. These facilities have direct control of the transmission system. Since the control centers in each of the five NEM regions has different vendors or versions of control software there is no single cyber-attack that could affect them all. There is also no internet connection between the regional control centers that would allow such a virus to spread. So while the chance of a cyber-attack on any region would be very low, an attack that would affect more than one region is impossible. Such an attack could bring down a region, but as discussed above, the blackout would be limited by the existing transmission break points to that region.

Multiple regions could be affected only by multiple targeted cyber-attacks that would have to be well planned and coordinated to occur simultaneously. Software viruses would have to be developed for each control center; the virus would have to be introduced by an employee, and then virus would have to be self-triggered at the same time. We believe that such a cyber-attack is not credible.

3. Defining sub-networks

The SRS provides guidelines for determining electrical sub-networks, specifically, that: "The AEMO shall determine the boundaries for electrical sub-networks without limitation by taking into account the following factors:

- "The number and strength of transmission corridors connecting an area to the remainder of the power system;
- "The electrical distance (length of transmission lines) between generation centres;
- "The quantity of generation in an area, which should be in the order of 1,000 MW or more; and
- "The quantity of load in an area, which should be in the order of 1,000 MW or more."[16]

In their *System Restart Ancillary Services–Draft Report* the AEMO proposes that only one SRAS resource be procured for each sub-network and that some sub-networks be combined:[17]

- North and Central Queensland;
- North and West Victoria; and
- North and South Tasmania.

The AEMO conducted a number of technical studies of the impact of these changes that showed that the SRS timeframes could be met.[18]

3.1 DNV KEMA understanding of the SRS

The SRS has, in effect, two requirements for sub-networks: first that the electrical strength of the transmission corridors and electrical distance be considered; and second, that the load and generation be at least 1,000 MW. The first is consistent with the presentation of transmission break points discussed in the previous chapter. The second is discussed below.

3.2 Sub-network boundaries

The existing sub-network boundaries are discussed in the AEMO's *Boundaries of Electrical Sub-Networks*.[19] The AEMO's proposed changes are discussed in their *System Restart Ancillary Services–Draft Report* and Appendix 2 of the *System Restart and Ancillary Services Review Issues and Options*

16. *System Restart Standard*, Reliability Panel, 1 August 2013, §6.
17. *System Restart Ancillary Services–Draft Report*, AEMO, 10 May 2013, §6.2.2.
18. Further details of these technical studies are set out in Appendix 2 of the *System Restart and Ancillary Services ReviewIssues and Options Paper,* the AEMO, 25 January 2013.
19. 15 December 2011.

Paper.[17,18] The suggested changes were shown in Table 5, on page 21, above and are summarized in Table 8. In short, the AEMO proposes that the total number of sub-networks be reduced from10 to 7.

Table 7: Sub-networks—now and proposed by AEMO

	Now	Proposed
Queensland	3	2
New South Wales	2	2
Victoria	2	1
South Australia	1	1
Tasmania	2	1
Total	10	7

3.3 Review of sub-networks

The SRS guidelines are reasonable in establishing sub-networks. We generally believe that it makes sense that the sub-network boundaries should be defined by likely transmission break points in meeting the first two guidelines—number and strength of transmission corridors, and electrical distance. This approach will only change one sub-network boundary (in New South Wales) from what was recommended by the AEMO.

3.3.1 Queensland

Queensland now has three sub-networks and the AEMO recommends combining the north and central sub-networks. The Queensland-North sub-network has about 1,300 MW of load and 1,200 MW generation. Only Tasmania is smaller. The existing north-central boundary is between the Broudsound and Nebo substations that includes 4 x 275 kV and 1 x 132 kV circuits. These circuits should have more than enough capability to serve the entire load in the existing sub-network without any local generation. The existing Queensland-Central sub-network is larger with about 2,000 MW of load and 5,300 MW of generation.

The proposed new combined Queensland-North would have about 3,300 MW of load and 6,500 MW of generation. The new Queensland-North does not have an obvious transmission break point. We believe that the existing Queensland-North and Central sub-networks should be combined.

The Queensland-South sub-network has about 5,700 MW of load and 7,100 MW of generation. It is electrically larger than the proposed combined North/Central sub-network. The AEMO has not recommended any change to this sub-network. We have discussed the break-point along the Queensland–

New South Wales boundary (§2.3.2.2 on page 30, above) and will address a suggested change in the next section. We believe that Queensland-South should continue as a sub-network.

3.3.2 New South Wales

New South Wales is the largest electrical region in the NEM with about 14,800 MW of load and 16,500 MW of generation. The region is now split into two sub-networks with the boundary just north of Sydney. The AEMO has not proposed any changes to these sub-networks.

As discussed in §2.3.2.2 beginning on page 30, above, the existing New South Wales sub-network boundary is not a transmission break point. The transmission break point would be a short distance north as shown on Figure 6 on page 30, above. Using our suggested sub-network boundary, however, would involve at least two other changes.

Our proposed New South Wales-North sub-network would not meet the SRS guidelines because it would have no generation. We believe the solution would be to combine this area of New South Wales with the existing Queensland-South sub-network.

Our proposed New South Wales sub-network would include all the generation in New South Wales and nearly all the load in a single sub-network. This sub-network would include a strong interconnected transmission network between Redbank in the north and Dederang in Victoria with branches to Nyngan and Broken Hill.

We note that the AEMO has identified issues that would require this new New South Wales sub-network to have two SRAS resources. In their boundary report they note that:

> "The distance between the Snowy generation group in NSW-South and the NSW-North generation groups is significant. It is likely to take in excess of two hours to fully re-energise the transmission network between the two electrical sub-networks."[20]

We believe that such a new New South Wales sub-network will likely require two SRAS resources.

While we believe that our proposed sub-network boundaries would be better than the existing boundaries from an electrical perspective, we have not made any technical studies; nor have we considered other factors that would weigh against our suggestions.

20. *Boundaries of Electrical Sub-Networks*, AEMO, 15 December 2011, Schedule 1, page 7.

3.3.3 Victoria

Victoria is the second largest electrical region in the NEM with about 10,600 MW of load and 12,400 MW of generation. The region is now split into two sub-networks with the boundary running through the Melbourne area. The AEMO has proposed that these two sub-networks be combined into one.

As discussed in §2.3.2.3 beginning on page 31, above, the existing Victoria sub-network boundary is not a transmission break point. In §2.3.2.3 we described the three areas of Victoria—the area from Heywood to the Latrobe Valley, the connection between Melbourne and New South Wales, and the less-densly populated area northwest of Melbourne.

The Heywood–Latrobe Valley area has nearly all the load and generation in the state and is highly interconnected. This area also has strong connections to the New South Wales border. There is no obvious transmission break point between these areas. The remaining area northwest of Melbourne has little load and generation and would not qualify as a sub-network.

We agree with the AEMO's recommendation that Victoria should be a single network. We also agree that only one SRAS resource is needed in Victoria.

3.3.4 South Australia

South Australia is a single network; it has no sub-networks as discussed in §2.3.2.4on page 33, above. The AEMO has not suggested a change and we agree. There is no apparent transmission break point in South Australia.

3.3.5 Tasmania

Tasmania is the smallest electrical region in the NEM with about 1,800 MW of load and 2,700 MW of generation. Tasmania is now split into two sub-networks with the boundary running between the Palmerston and Waddamana substations as shown in Figure 9 on page 34, above. The AEMO has proposed that these two sub-networks be combined into one.

While the existing sub-network boundary could be considered a transmission break point as discussed on §2.3.2.5 on page 34, above, we believe there is no need for two sub-networks in Tasmania as there is no likely transmission split point. We agree with the AEMO that Tasmania should be a single sub-network. We also agree with the AEMO that Tasmania should have two SRAS resources.

4. SRAS definition, quantity and assessment

As defined by the NER, SRAS is 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."

The NER mention power stations and generating units as typical examples of such facilities, but we note that the definition of "facilities" in the NER does not rule out other options for SRAS facilities such as energy storage systems.

The AEMO is required to develop and publish SRAS "Quantity Guidelines" in accordance with §3.11.4A(f) of the NER, which states: "AEMO must develop and publish the procedure for determining the number, type and location of SRAS required to be procured for each electrical sub-network consistent with the SRS determined by the Reliability Panel (the SRAS quantity guidelines)." In doing so, AEMO is required to comply with §3.11.4A(c) of the NER which states that each of the guidelines and SRAS description which AEMO is required to develop and publish in accordance with clause 3.11.4A must be:

(1) consistent with the SRAS objective;

(2) designed to ensure the SRS is met; and

(3) designed to ensure that the need for SRAS in each electrical sub-network is met, to the extent that it is practicable and reasonable to do so, by AEMO entering into ancillary services agreements for the provision of primary restart services.

Specific SRAS performance targets are further delineated by the Reliability Panel in the SRS which was determined according to clauses 8.8.1(a)(1a) and 8.8.3 of the SRS. Per the standard, for each electrical sub-network, AEMO shall procure SRAS sufficient to:[21]

- re-supply and energize 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.

These restoration times represent 'targets' to be used by AEMO in the procurement process. They are not a mandatory operational requirement to be achieved in the event of a blackout. These targets apply equally

21. Reliability Panel – System Restart Standard, 1 Aug. 2013

across regions unless varied by the Reliability Panel on the basis of technical system limitations or the costs and benefits for the region. The AEMO is not proposing a change to the Reliability Panel targets.

In the proposed SRAS regime AEMO will accept service tenders for delivery of such service from trip-to-house load (TTHL) facilities, hydroelectric generating facilities, gas turbines or other types of facilities that meet the SRAS requirements. These are discussed further below.

In both the current and proposed regimes AEMO assumes that there is no damage to generation or transmission infrastructure as a result of the blackout event. In other words, it assumes that all facilities are available for restarting each sub-network. In our experience this is often the case, but it will not be so in every case. On the other hand, AEMO has built a conservative assumption into its black start scenario description for the proposed regime by assuming that each sub-network must be capable of starting from either the single winning SRAS tender or from the interconnectors to neighboring sub-networks. This single black start criterion is conservative because in almost every case both the internal SRAS unit(s) and most interconnectors will be available during the restart process. In view of this expectation, we find the AEMO assumption of "no infrastructure damage" to be reasonable for the purpose of SRAS tender assessment.

4.1 Revised definition of SRAS

The SRS currently defines both primary and secondary SRAS tenders. In the current regime the AEMO always tries to procure primary SRAS, but utilizes secondary SRAS when insufficient primary SRAS tenders were available in a given sub-network. The AEMO now proposes to eliminate the primary and secondary SRAS categories and define a single class of SRAS tender. We understand that the SRS will need to be changed in order to remove the primary and secondary services.

The second change in the SRAS definition proposed by the AEMO is to modify the description of the target bus to be energized. Under the current regime, in order to help ensure that a primary SRAS can re-supply and energize the auxiliaries of a large generator in 90 minutes or less, the AEMO actually requires that an SRAS tender be able to energize the a large generator's auxiliaries in 60 minutes or less. This provides a 30 minute margin to cover for operational contingencies. However, under the current regime the AEMO has found some SRAS tenders can only achieve the 60 minute time requirement by energizing an adjacent larger generating unit (i.e., located at the same power station as the SRAS unit). Although this technically meets the wording of the 90 minute target in the standard, the AEMO reports that SRAS tenders using this approach are often unable to support the transmission system restoration speed necessary to meet the Standard's four hour restoration target.

Hoping to avoid this situation in the future, the AEMO proposes to redefine the SRAS energizing target. Rather than energizing the auxiliaries of a target large generating unit, the AEMO proposes having the SRAS energize a target *transmission* bus in 60 minutes or less. We observe that the current SRAS definition clearly meets the 90 minute target of the Standard, while falling short of the four hour target in many cases. While the AEMO's proposed definition improves the likelihood of meeting the Standard's four hour target, it seems to increase the uncertainty over whether a full cranking path can be established from an SRAS to a larger generation station auxiliary bus within the Standard's 90 minute target. The AEMO's proposal assumes that the second part of the restoration sequence (routing power to a transmission bus near the SRAS to a large generator's auxiliaries) can be completed within 30 minutes. As a general assumption this may be optimistic, although it may be achievable in many cases. Therefore, we recommend that the AEMO consider setting a shorter target time for SRAS tenders to energize the closest transmission bus (e.g., 45 minute). This would allow more time for energizing the rest of the cranking path over the transmission system to the next larger generation plant auxiliary load supply bus and significantly improve the likelihood of meeting the Standard's 90 minute target. The actual time that an SRAS tender proposes to use for energizing a transmission bus should also be included in the AEMO's "value determination" of the proposed SRAS tender. A tender that can do so in less time should be given a higher ranking in the assessment while slower SRAS tenders should be given a lower ranking.

A summary of these SRAS options is provided in Table 8.

Table 8: Comparison of SRAS options

Option	Target bus to be energised	Max. time to energise target bus	Other require-ments for the SRS's 90 min. target	Comments
Existing regime	Targeted large generator auxiliary bus	60 min.	None	Provides a 30 min. margin for operating contingencies Does not always assist with other SRS requirements
AEMO proposed regime	Transmission bus in vicinity of the SRAS unit(s)	60 min.	Energize cranking path from SRAS transmission bus to a large generator	Assuming only 30 min. seems overly optimistic
DNV KEMA recommendation	Transmission bus in vicinity of the SRAS unit(s)	~45 min.	Energize cranking path from SRAS transmission bus to a large generator	Include actual time quoted by SRAS tender as a factor in value determination

In addition to reducing the target time for energizing a transmission bus, we recommend that the AEMO consider implementing the following measures to help ensure that the standard's 90 minute restoration target can in fact be met by "winning" tenders:

- Confirm through detailed simulation that each step of energizing the cranking path plan and remote generating unit start up is technically feasible. This should include steady-state, dynamic and transient (e.g., EMTP) modeling and analysis.
- Agree on procedures with applicable network service provider(s) to fulfill the switching plans, procedures and timelines needed to achieve the 90 minute target.

The AEMO has experienced a number of undesirable outcomes with the current SRAS approach. Some winning SRAS tenders are able to energize the auxiliary bus of a specified large generator within 90 minutes, but then the specified generator is either unable to restart within 4 hours or unable to effectively route power from that plant over the grid to other large plants within 4 hours.

In other cases the AEMO reports that insufficient primary SRAS tenders have been received to meet the targets and that the AEMO has then had to rely on secondary SRAS tenders in an attempt to close the gap. As a result of such issues the AEMO is concerned that in an actual blackout it might be unable to meet the SRS restoration targets. The AEMO now proposes to remedy this perceived shortcoming through redefining the SRAS tender requirements.

In its new approach the AEMO proposes connecting SRAS generation output to a nearby transmission bus as quickly as possible. This would allow the AEMO to route power over the grid to the auxiliary busses of other power stations more quickly, flexibly, and effectively than it can in the current approach. By introducing this change, along with other changes to the SRAS definition, the AEMO seeks to develop a portfolio of tenders that will have a higher likelihood of meeting the 90-minute and 4-hour targets of the SRS.

We observe that in both the current regime and the proposed regime there is a given portfolio of generation resources in the NEM. Some of these resources have black-start capability, but many do not. It is unlikely that the proposed approach will incentivize construction of new black-start generation resources. However, it is possible that the new approach could make it possible for more of the existing black-start resources in NEM to participate in the SRAS tender process and, in some cases, might even incentivize other generation owners to consider making minor modifications that could enable them to submit an SRAS tender.

We further conclude that the AEMO's proposed changes to SRAS tender requirements and definitions should improve the likelihood of meeting the SRS targets and make the tender process more competitive by allowing or encouraging more tenders to be submitted in future SRAS solicitations.

Finally, we observe that a more rigorous AEMO technical assessment process for SRAS tenders would improve the likelihood of actually meeting the SRS targets. In the body of the report we provide a preliminary outline for a more rigorous a technical assessment methodology for consideration by the AEMO.

4.2 Minimum SRAS size

The AEMO's requirement now is that each primary tender be able to quickly energize at least 100 MW of generating capacity. In discussions with the AEMO we confirmed that there is no documented technical basis for their current 100 MW minimum size. We also confirmed that the auxiliary loads of each of the largest generating units in NEM are approximately 20-30 MW—much smaller than 100 MW. Due to the associated motor starting requirements for the type of large auxiliary motors found in power plants, the capacity of black start units typically needs to be larger than the steady state auxiliary loading. The exact amount depends on a number of technical factors and can only be determined precisely through technical study of a specific black start scenario. Since the AEMO has not performed a detailed technical analysis of such starting requirements, it appears the 100 MW minimum rating for SRAS tenders was adopted as a conservative estimate of the actual need.

The AEMO's proposed approach requires that the SRAS tender itself be capable of generating at least 100 MW, rather than relying on the larger generating unit it starts to provide the 100 MW under the present approach. We observe that this minimum capacity requirement is an arbitrary value. In fact many similar international regional reliability organizations do not establish a minimum capacity for black-start tender purposes. While an SRAS tender capacity of 100 MW should be more than adequate to start the auxiliaries of any large generating unit in the NEM, it is possible that smaller SRAS tenders could do likewise.

The key question is whether a tender can meet the functional requirements and targets defined by the SRS. We recommend that the AEMO evaluate the pros and cons of relaxing or eliminating the minimum SRAS tender size in the proposed regime. Even a reduction to 75 MW might enable a number of additional generation providers to offer SRAS tenders, making the process more competitive. Regardless of the size of the tender, the AEMO's assessment methodology should be designed to determine if a tender can meet the functional requirements and targets of the standard.

4.3 Number of SRAS tenders per sub-network

In the past AEMO has sought to acquire black-start services from two independent SRAS providers (tenders) in each sub-network. This was based on the premise that a sub-network shouldn't rely on interconnectors with neighboring sub-networks to restart following a blackout, and the criterion that with two SRAS providers in each sub-network it will still be possible to restore a sub-network in the event that any single SRAS unit is unable to start. We concur that having contingency capability for the failure of any one black start provider is prudent.

In the new regime, the AEMO proposes to reduce the minimum number of SRAS tenders per sub-network to one, based on a revised assumption that interconnectors with neighboring sub-networks will serve as the primary black start source . We find this to be a reasonable approach and do not anticipate any degradation in NEM reliability as a result of this change. However, since the Tasmanian sub-network only has an HVDC interconnector to its neighbors which is unable to operate during a black start condition, AEMO proposes to keep the requirement for two independent SRAS tenders in this one sub-network.

In addition, we note that if the AEMO determines through its technical tender assessment process that no single SRAS tender achieves the standard, it should consider suitable mitigation options such as procuring service from more than one SRAS provider in a sub-network.

4.4 Impact of SRAS changes on reliability and competition

Clearly the best outcome from the AEMO's proposed changes to the SRAS quantity and definition would be to maintain the reliability benefit of the winning tenders while simultaneously increasing the competitiveness of the tender process. While quantifying such impacts in a prospective sense is impossible, we offer the following qualitative assessment based on our experience with markets and engineering judgment.

Table 9: Impact on reliability and competition

Factor	Impact on NEM reliability	Impact on competition
Reduction to a single SRAS per sub-network	Negligible impact	Increased competitiveness of tender process
Elimination of primary and secondary SRAS definitions	Negligible impact	More incentive to bid on remaining SRAS category
Change in target bus for SRAS energisation to a transmission bus	Negligible impact	Increased competiveness of tender process

We have not included the impact of lowering the minimum SRAS tender size to less than 100 MW in the above table because it has not yet been fully vetted by AEMO. If adopted, we believe it could markedly increase competitiveness of the tender process. However, it would require a broader range of technical modeling during the tender process to ensure reliability is maintained.

4.5 Technical modeling of SRAS tenders

In the past the AEMO has only performed steady-state (powerflow) modeling of SRAS tenders. Industry best practice is to also perform dynamic/transient modeling when developing black start plans. While powerflow modeling can identify potential overloads and some steady-state voltage issues in an

SRAS/cranking path analysis, many other types of technical issues can occur in dynamic and/or transient conditions. For example, reliance on powerflow simulation alone is not adequate to identify the following types of technical concerns that can occur during black start/restoration activities:

- Unacceptable voltage or frequency swings during generator auxiliary motor starting;
- Black start generator "pull-out" or angular instability;
- Transient/switching over voltages;
- Short-term system over-voltages or over-frequency conditions as a result of load rejection; or
- Transformer energizing/self-excitation concerns.

Thus, we believe that the AEMO should perform dynamic/transient modeling when evaluating SRAS tenders. Reliance on powerflow modeling alone does not confirm a fully workable black-start plan. It could result in payments to SRAS providers for services they can't actually deliver. Even worse, it could result in equipment damage or failure during actual restoration efforts, thus further complicating the overall restoration effort and incurring expensive equipment repair or replacement.

The AEMO has advised DNV KEMA that it does not now have access to all the necessary dynamic or transient data for either the transmission network or generating facilities. AEMO believes its network service providers have such model data for the transmission system, but is unsure if either the network service providers or generation providers have accurate dynamic/transient modeling data for the generators. In our experience, this type of data is required for studies used in system expansion planning, so it probably resides somewhere within the NEM.

We recommend that the AEMO investigate the available sources for such modeling data and consider options for performing such modeling in future SRAS tenders including:

- Obtaining such data and performing the associated dynamic/transient modeling;
- Delegating to or contracting with the applicable network service providers to perform such analysis; and
- Retaining the services of a qualified consultant to perform such modeling for the AEMO.

If the AEMO determines that detailed dynamic/transient modeling data is not currently available in the NEM, it should consider using "typical" data for the applicable generators and cranking path facilities involved in the expected restoration sequence to perform the technical analysis of SRAS tenders.

In addition to reducing the risk of equipment damage or failure, including dynamic/transient modeling in the SRAS tender review will help to remove inadequate performers from the list of winning tenders and provide the AEMO with vital information on cranking path or switching steps that must be observed for successful system restoration.

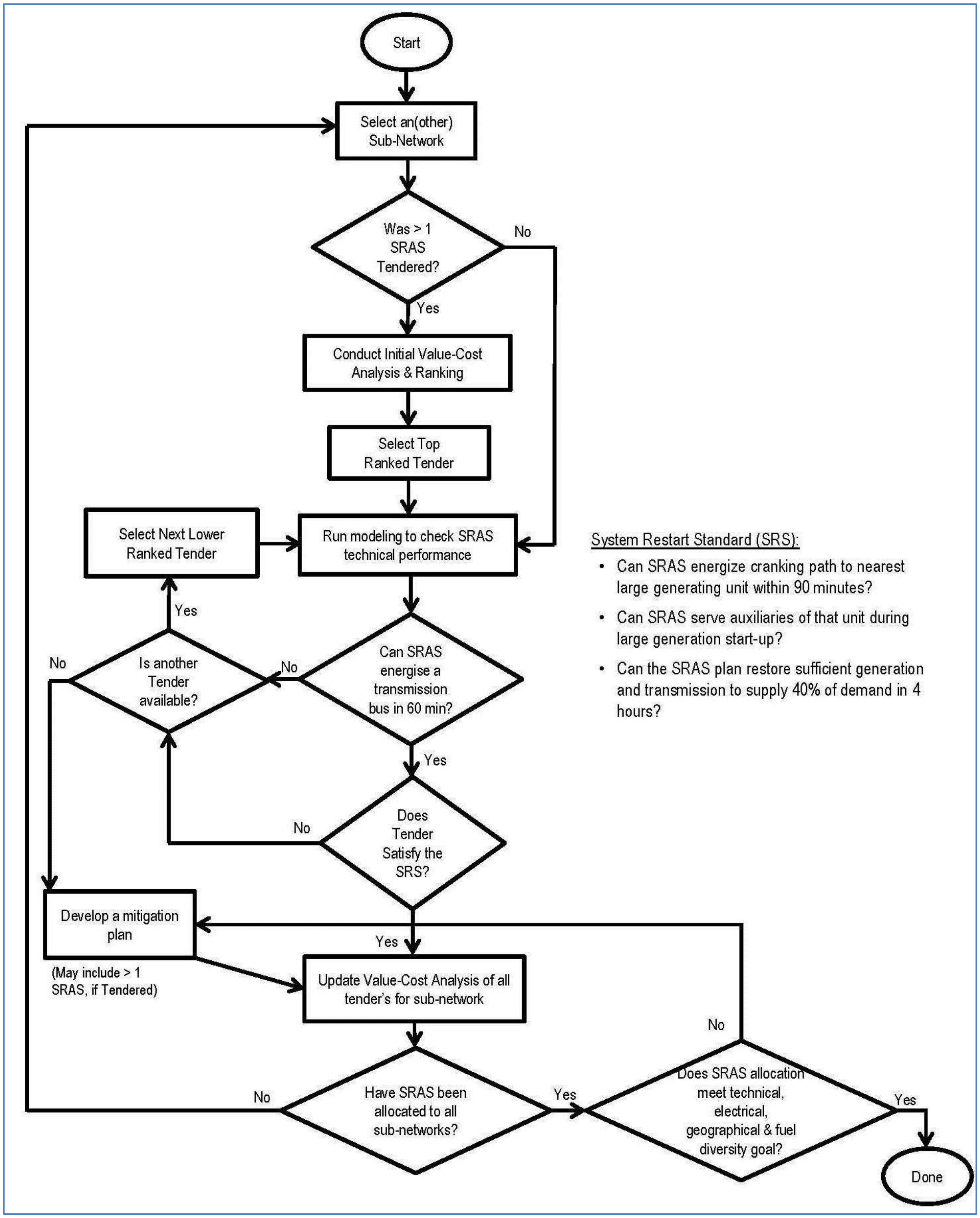
We envision, that with our recommended approach, an initial-value cost-determination of tenders would be performed by the AEMO to select which set of tenders to assess through technical modeling. The value-cost determination may need to be updated as a result of the technical modeling. In some cases, no tenders may meet the technical targets and mitigation plans will need to be developed. Such plans might include procuring service from more than one SRAS tender in a given sub-network in order to achieve Reliability Panel targets. A conceptual tender technical assessment process is shown in the flow chart of Figure 15.

We also note that the range of testing performed should include both n-0 and n-1 conditions. The AEMO advises that this has been their current practice, albeit limited to steady-state (power flow) modeling in the past. The n-0 and n-1 approach should evaluate the performance of each winning SRAS tender at both the 90 minute and four hour targets of the SRS.

In the event that the AEMO determines through its assessment that no single SRAS tender in a given sub-network is able to achieve the 90 minute and four hour targets, a mitigation plan needs to be developed which could include:

- Adding a second SRAS in a sub-network;
- Redefining the sub-network boundaries; and/or
- Changing the number of sub-networks.

Figure 15: SRAS tender technical assessment process



4.6 International practices

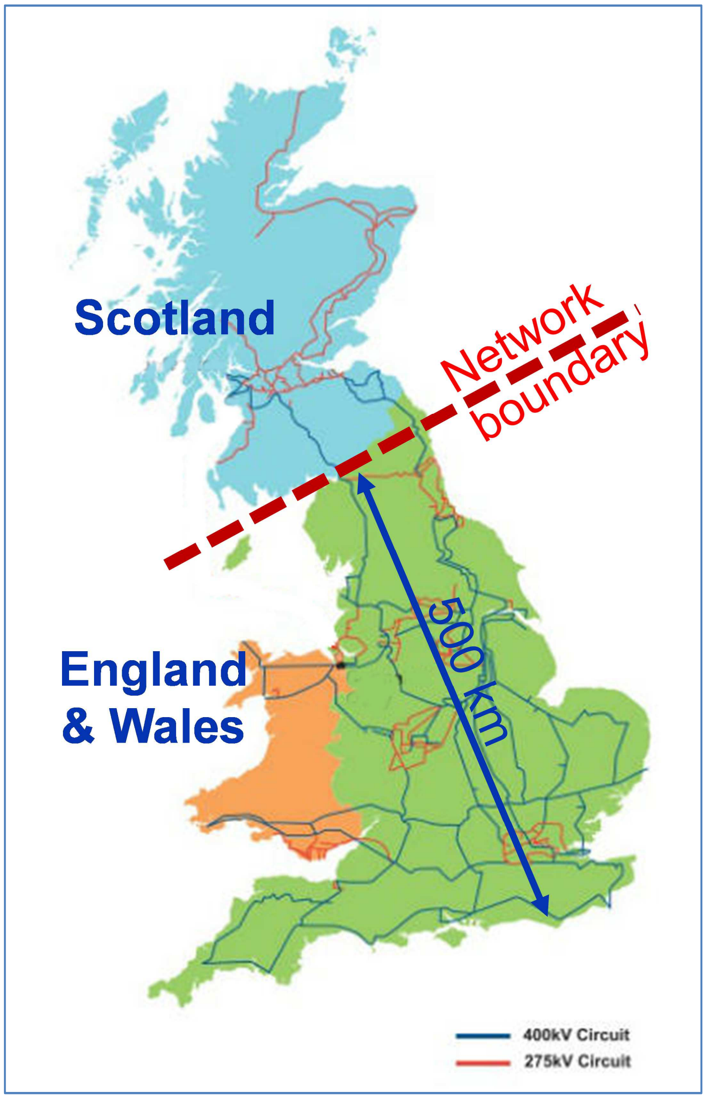
This section presents a brief comparison of international practices similar to those being addressed in this report. Six international systems were selected for comparison regarding blackout/restoration planning. The comparison includes systems from the United Kingdom, North America, and South Africa. The systems were selected based on some similarity with the NEM system and availability of information regarding blackout/restoration practices. Comparisons were made using public information sources that had varying levels of specific information, supplemented, in some cases, by our personal knowledge.

4.6.1 England and Wales

The England and Wales transmission network is operated by National Grid–United Kingdom (NGC). NGC is the system operator for England and Wales (Scotland has its own networks). NGC owns and maintains the high-voltage electricity transmission network, balancing supply with demand on a minute-by-minute basis.

The NGC system has a peak demand of about 56,000 MW served by about 80,000 MW of generation. The transmission grid includes 400 kV, 275 kV, and 132 kV transmission lines. The transmission system is shown in Figure 16. The system has AC interconnections with Scotland and HVDC connections to transmission systems in France, the Netherlands and Northern Ireland. The network is about 500 km from the Scottish border to the English Channel. There is a transmission break-point with the Scottish network.

Figure 16: NGC–UK transmission system

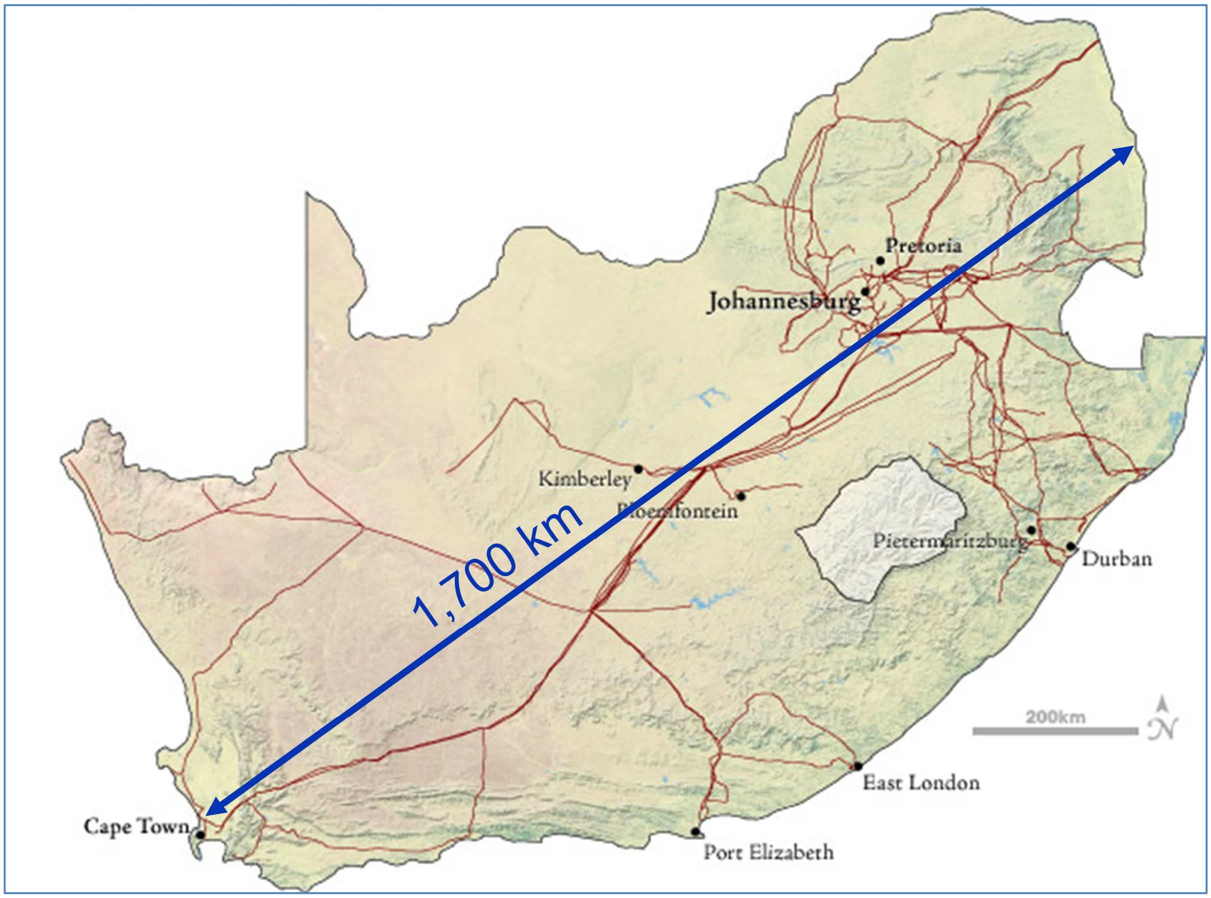


4.6.2 South Africa

Established in 1923 by the government of South Africa, ESKOM is South Africa's primary electricity supplier and is wholly owned by the South African government. ESKOM is a vertically integrated utility that generates, transmits and distributes electricity to industrial, mining, commercial, agricultural and residential customers. It also sells electricity to municipalities, which in turn redistribute it to businesses and households within their areas.

With a peak load of about 37,000 MW, ESKOM is the largest electricity producer in Africa. The transmission grid includes 765 kV, 400 kV and 275 kV transmission lines and has AC interconnections with Namibia, Botswana, Zimbabwe, Mozambique, Swaziland and Lesotho. The transmission system is shown in Figure 17. The network is about 1,700 km long.

Figure 17: ESKOM, South Africa transmission system

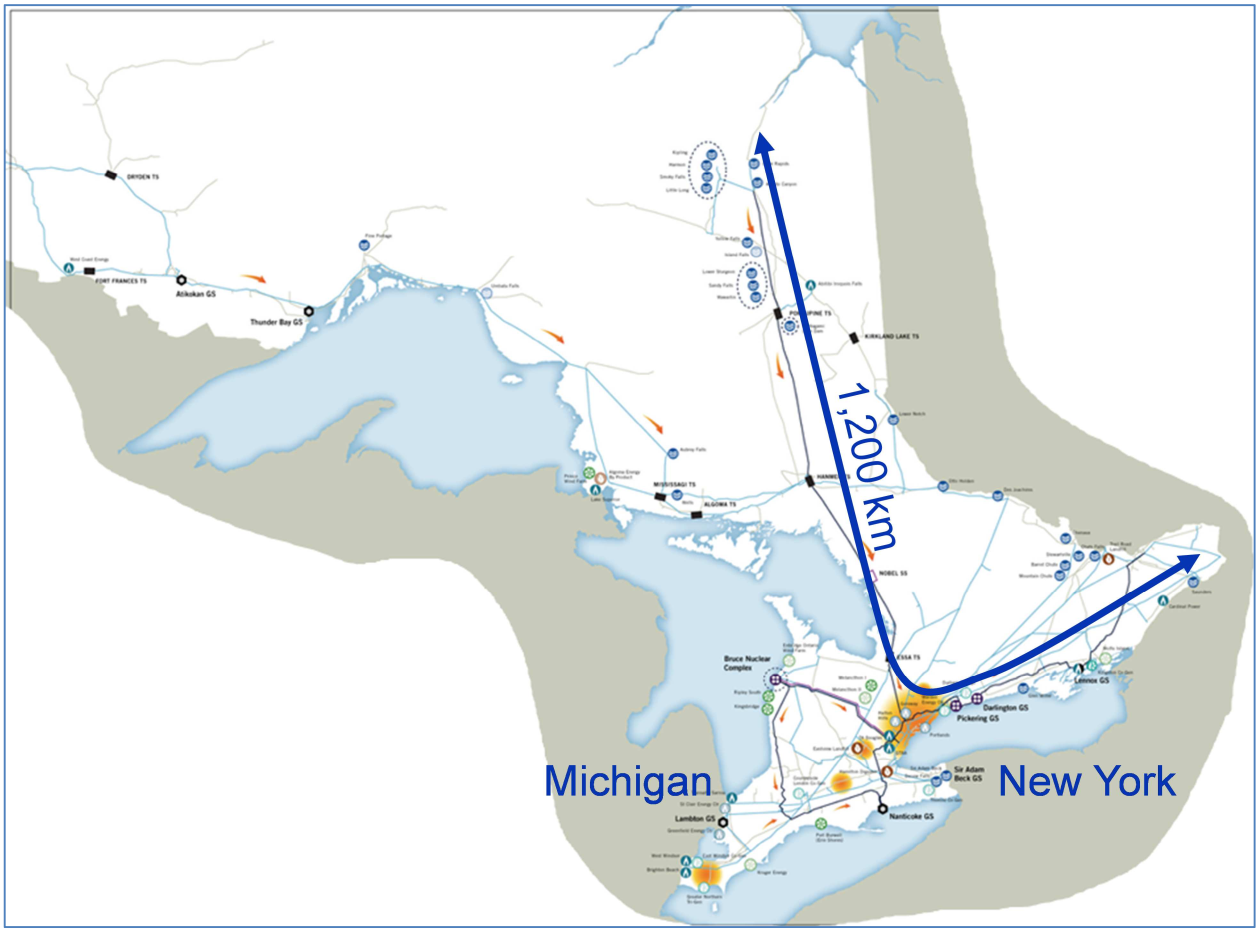


4.6.3 Canada–Ontario

The Ontario Independent Electricity System Operator (IESO) is Ontario's power system operator, connecting all participants - generators that produce electricity, transmitters that send it across the province, retailers that buy and sell it, industries and businesses that use it in large quantities and local distribution companies that deliver it to people's homes. The IESO serves the entire Ontario Province balancing supply and demand while maintaining system reliability.

The IESO system has a peak demand of about 25,000 MW. The transmission grid includes 500 kV, 230 kV and 115 kV transmission lines. The transmission system is shown in Figure 18. Ontario has AC connections with Manitoba, Michigan, Minnesota, and New York, and HVDC connections with Quebec. Michigan and New York are the most significant with about 1,500 MW import capability each.

Figure 18: Canada, Ontario transmission map

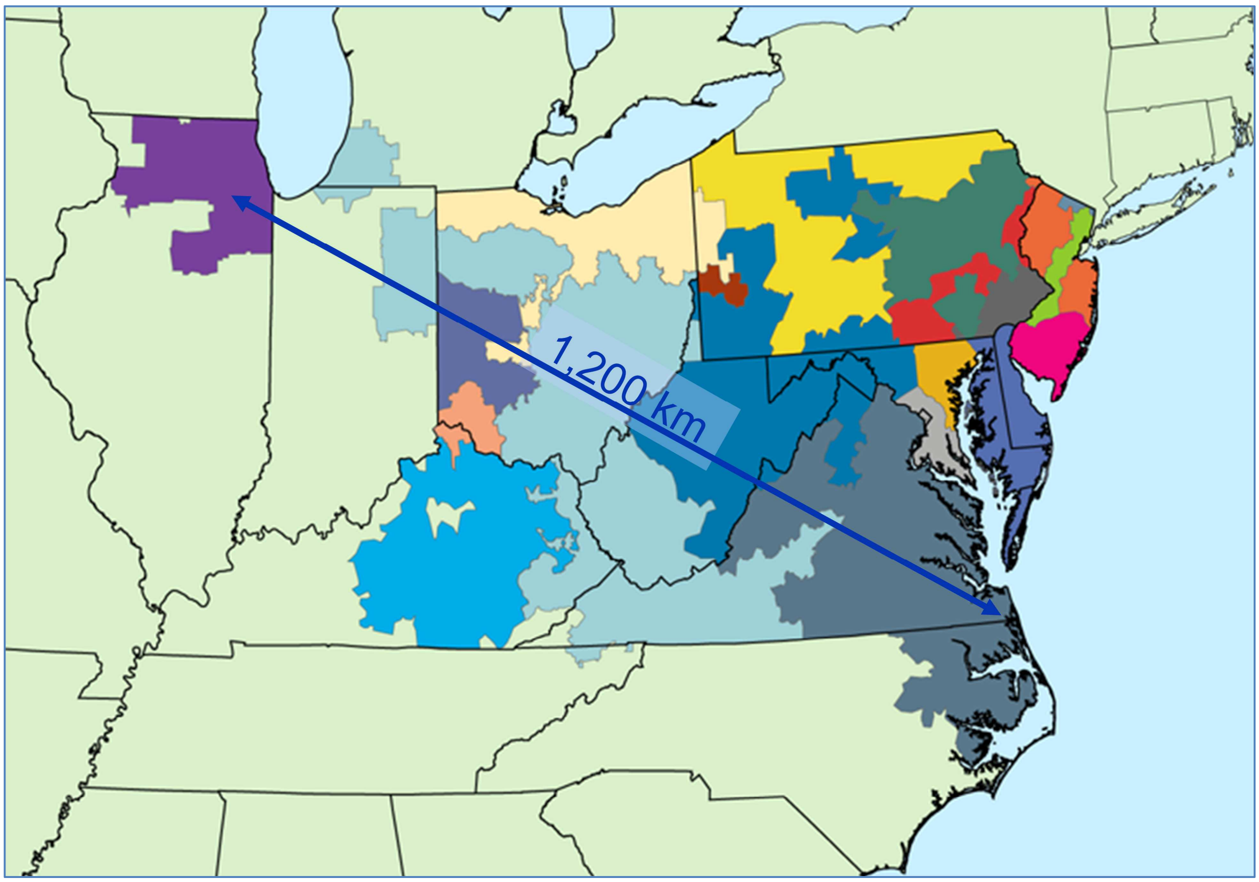


4.6.4 United States–PJM Interconnection

The PJM Interconnection is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of 13 states and the District of Columbia. PJM operates, but does not own, the transmission systems and it operates the power market within its area.

The PJM system serves about 160,000 MW of customer demand. The transmission system includes 765 kV, 500 kV, 345 kV, 230 kV, and 115-132 kV transmission lines. The system is about 1,200 km across and has dozens of AC interconnections with the surrounding states. Figure 19 shows the region covered by PJM and the transmission zones. The 20 zones within PJM generally correspond to the boundaries of the transmission owners.

Figure 19: PJM transmission zones

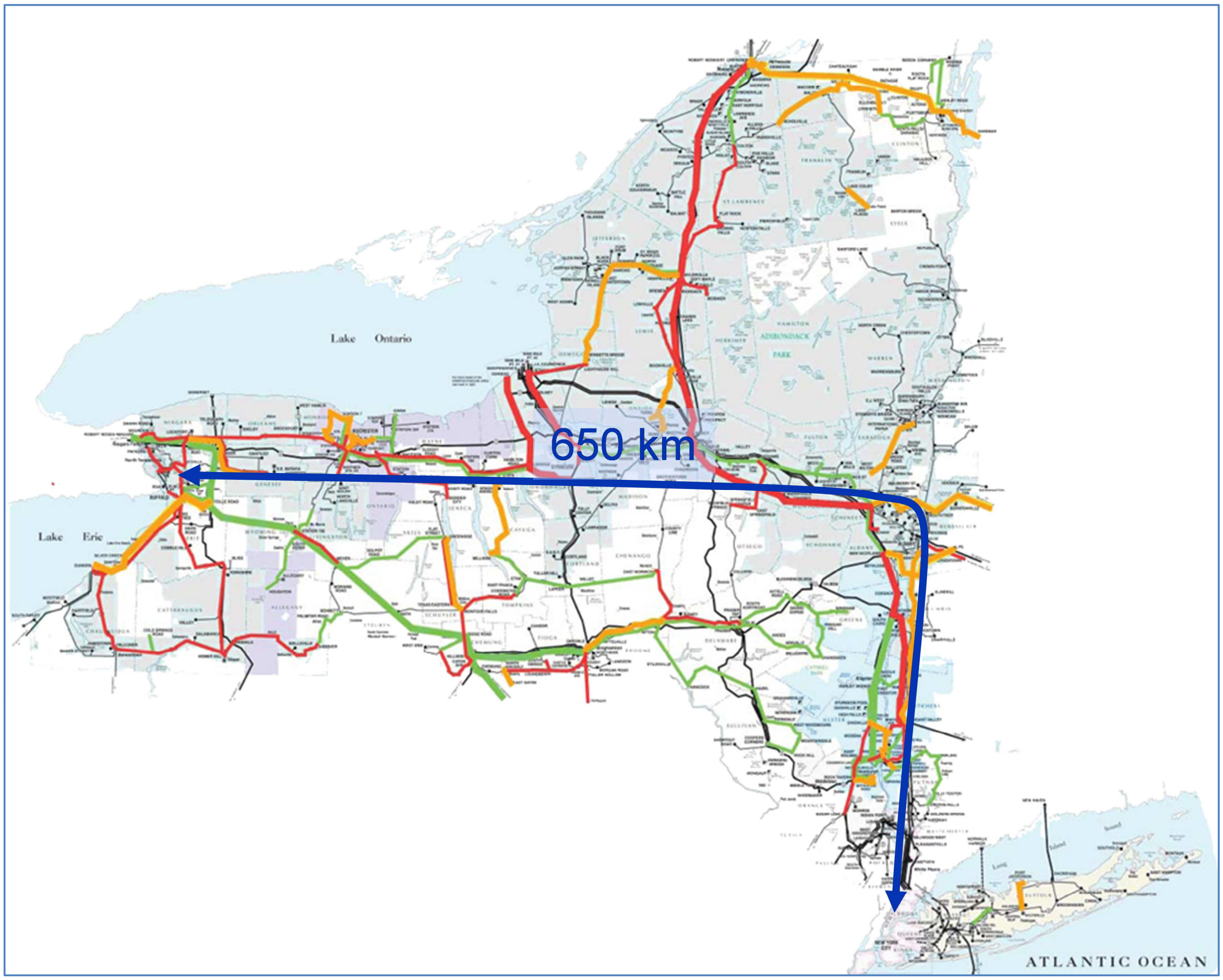


4.6.5 United States–New York

The New York Power Pool was formed in 1969 in response to the 1965 Northeast Blackout and evolved into the New York Independent System Operator (NYISO). The NYISO operates the New York electric system. The NYISO operates, but does not own, the transmission facilities of eight transmission owners. The NYISO also operates the power market for the area.

The NYISO system has a peak demand of about 35,000 MW. The transmission system includes 765 kV, 500 kV, 345 kV, 230 kV, and 115-132 kV lines as shown in Figure 20. The backbone of the network is 345 kV transmission extending 650 km from west-to-east and south to New York City. The system has strong AC interconnections to the Toronto area in the west and the rest of Ontario to the north and a back-to-back HVDC connection with Quebec. There limited interconnections to the south and east.

Figure 20: New York transmission system

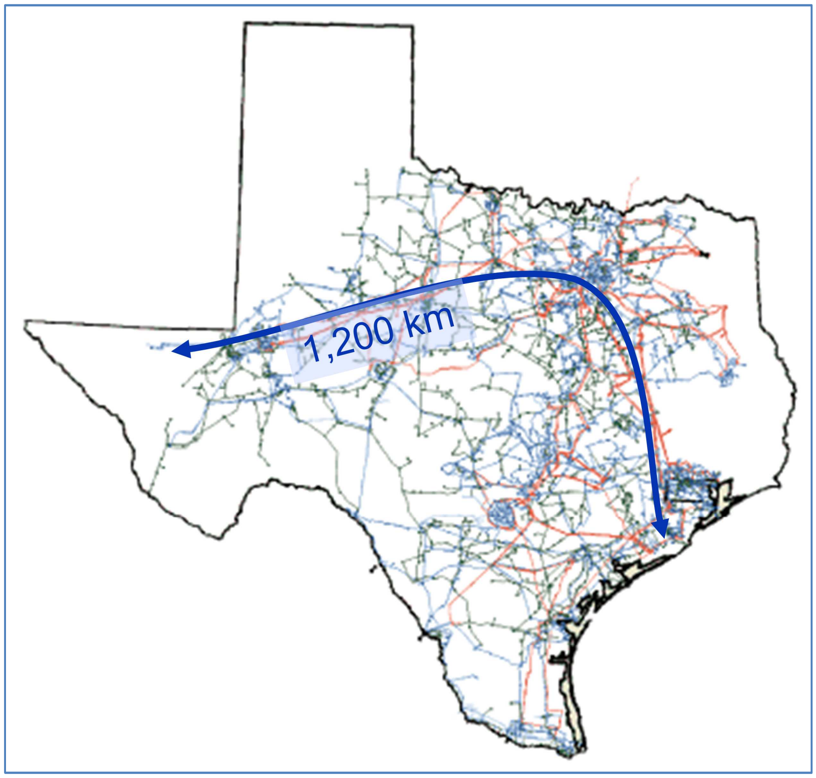


4.6.6 United States–Texas

The Electric Reliability Council of Texas (ERCOT) manages the flow of electric power to 23 million Texas customers representing 85% of the state's electric load. ERCOT operates, but does not own, 40,500 miles of transmission lines owned by four larger investor-owned utilities and dozens of municipal and cooperative systems. ERCOT also performs financial settlement for the competitive wholesale bulk-power market.

The ERCOT system has a peak demand of almost 70,000 MW. The transmission system includes 345 kV and 115-138 kV lines as shown in Figure 21. The system has only HVDC interconnections—820 MW to the north and east and 280 MW to the south.

Figure 21: ERCOT–Texas transmission system



4.6.7 Summary of international black-start/restoration practices

A brief summary of their practices regarding black-start is shown in Table 11 on page 71, below.

Each of the selected international systems makes blackout/restoration practice choices that are suited to their specific conditions. There are a number of specific system characteristics that affect these choices, including:

- Systems with densely meshed transmission networks will have few (or no) natural transmission break points. Such a system will likely consider a system-wide blackout as a credible event. An example would be NGC that has no clear internal transmission break points.

  There are also systems that are part of much larger networks that use "system-wide" in a different context than used in NEM. The PJM and NYISO systems in the US are part of a

700,000 MW synchronous interconnected network that will provide support during restoration if a blackout were to occur.

- Systems that have large amounts of generation that can be started quickly such as hydro-electric or the combustion turbines (CTs) in combined–cycle (CC) generating plants will have different practices than those with a lot of large coal-fueled or gas-fueled steam generating units. For instance, there have been thousands of megawatts new gas-fueled CC generators added in the US in recent years as new gas discoveries have lowered natural gas prices.
- Systems with weak interconnections will also have different practices. ESKOM in South Africa does not have adjacent power systems that are either large enough or dependable enough to be considered reliable sources for system restoration.
- Systems with Nuclear generation will have special strict requirements that give priority to restoring outside power to these plants.

4.6.7.1 Assumed system-wide or regional blackout

The AEMO proposes adopting a regional (not NEM-wide) blackout as the basis for black start planning and black-start unit (BSU) tenders. The AEMO also plans to provide at least two black-start sources using an internal black start unit or using interconnections with neighboring regions. The two approaches provide redundancy in that either can be used to restart the regional system in the absence of the other.

The AEMO approach appears to be generally consistent with international practice.

The NGC, ESKOM and ERCOT, however, cover much smaller areas geographically than AEMO and have more tightly coupled internal networks than the AEMO. These system also have limited or no interconnections to neighboring systems. Both of these factors increase the risk of a system-wide blackout and reduce the likelihood of restoration assistance from their interconnections.

For PJM, NYISO, and IESO—systems that are part of the 700,000 MW Eastern Interconnection in North America—a total system blackout has a different meaning than for the NEM. Even in a major blackout like that of August 2003 where nearly all of NYISO lost power, only part of the IESO and a very small part of PJM were blacked-out. And even within the NYISO that was most affected by the 2003 blackout, there was not a complete blackout as several power islands (electrical areas that maintained balanced generation/load) survived.

Given the characteristics of the AEMO system we conclude that a regional blackout assumption and use of interconnections as the primary restoration option are appropriate for their black start planning.

4.6.7.2 Approach used to develop black-start plan

Almost all of the entities we reviewed have their black-start/restoration plans developed by the overall system operator (a "top-down" approach). PJM, NYISO and ERCOT also expect studies for regional restoration from its individual member systems, but reserve the final decision-making authority.

Another observation from the international comparison is dependence by some of the entities on long-term black-start contracts. NGC often uses contract terms of 10 years or longer and does not conduct new solicitations for new black-start units unless there is a significant change in its requirements, such as retirement or contract expiration of an existing black-start unit. ESKOM tests black-start units on a regular basis to ensure performance, which infers the use of long-term contracts (or automatic renewals subject to performance testing).

4.6.7.3 Black-start unit qualifications and restoration target times

There are no consistent minimum size requirements for black-start units other than that they be functionally adequate to meet support the system restoration process. Time targets to restore a designated transmission bus or path range from as short as 30 minutes to as long as 4 hours.

IESO (Ontario) has different restoration time requirements depending on the BSU generator type (e.g., gas turbine, steam turbine or hydro).

4.6.7.4 Study and testing requirements

Entities generally require each black-start unit to demonstrate its starting capability every 1-3 years. ESKOM requires an actual field demonstration every 3 years that each black start plant can restart a designated, remote coal station. The IESO requires that each black-start unit be able to complete 3 black starts within an 8 hour period due to the likelihood of system re-collapse occurring during restoration.

The extent of modeling and simulation used in assessment of black-start units varies from entity to entity. Most entities seem to perform a mix of steady-state, dynamic and transient simulations. In assessing black-start units tenders NGC also performs probabilistic analysis with a grid restoration/risk assessment simulation tool that utilizes a Monte-Carlos approach for outage scenarios.

Best practices also take into account a diversity of fuel sources and geographical locations, with preference for black-start unit locations that have the shortest cranking paths to larger power plants.

4.6.7.5 Minimum number of black-start units

The minimum number of black-start units for each international system is shown in Table 10. The Table shows the number of zones and black-start units per zone. In some cases the number of zones is either not specified or can change from time to time.

Table 10: Minimum number of black-start units

Entity/region	Peak load (MW)	Zones	Minimum number of black-start units		
			Per zone	Total	Per 10,000 MW
National Grid-UK	56,000	6◊	2*	12	2.1
ESKOM	37,000	1	4†	8	2.2
IESO	25,000	3	1	3	1.2
PJM	160,000	10	2*	20	1.2
NYISO	35,000	3	2*	6	1.7
ERCOT	70,000	7♦	1 or 2*	10	1.4
AEMO (now)	35,000	10	2	21	6.0
AEMO (proposed)	35,000	7	1 or 2	8	2.3

Notes: * Excludes black-start units dedicated to energizing nuclear plants.
† ESKOM requires two multi-unit plants.
◊ The number of zones is estimated or typical where zones are not specifically defined.
♦ ERCOT does not specify a number of zones, but there are seven congestion zones.

Table 10 also shows the number of black-start units per 10,000 MW of system load. We offer this as a rough means to compare black-start requirements among the systems.[22] While many of the international systems require at least two black-start units, they are all much larger systems and zones than in the NEM. This is why we have used the black-start units/10,000 MW for comparison. Using this measure, the current AEMO minimum of 21 SRAS units for a 35,000 MW system load is much higher than the others. The AEMO proposed changes are much more in line with the other systems.[23]

22. Using black-start units per 10,000 MW of load is just one possible measure. It does not consider geographic distance, network topology, transmission break points, or cranking paths that could all be part of such a comparison measure.

23. There are many complicating factors in such a comparison, but one the most significant is black-start units required for nuclear power plants. Since the 2011 Japanese earthquake/tidal wave and the Fukushima nuclear plant accident there has been increased scrutiny of nuclear plant restoration. In North America it is common to require two separate black-start cranking paths to re-energize the substation at nuclear power plants. These black-start units and cranking paths are dedicated to restoring their selected plants and not to help restore other parts of the system. Following a blackout, North American nuclear power plants would not be expected to supply power to the network for at least several days.

    As an example consider Dominion Virginia Power (DVP). DVP is zone within PJM that serves customers in most of Virginia and part of North Carolina with a peak load of about 20,000 MW. DVP operates two nuclear plants that have at least two dedicated black-start units each. So this PJM zone has at least six black-start units, though only two are for general black-start service.

Table 11: International comparison of black-start planning requirements

Entity or region	System-wide or regional black-out/interties	Develop top down or bottom up black-start plan	Black-start unit qualifications	Restoration time targets or requirements	Study and/or testing requirements
National Grid-UK (England & Wales)	BSUs must be in their zone. System-wide with no support from other countries Each zone must be able to restart without ties.	Top down. Incremental revisions to BSU contract portfolio when needed due to a BSU retiring or other important change. Silent on TTHL.	≥ 2 per zone, but zone boundaries are flexible. Spread across zones, reduce distance to large plants, ≥90% start probability, lowest cost. BSU must support instantaneous load blocks of 35-50 MW.	BSU must be able to energize local transmission bus in 2 hrs. Target to restore all UK transmission in 12 hrs, but no specific times in the Grid Code.	Uses a grid Monte Carlo restoration/risk assessment simulation tool to help select the best BSU tenders; Also has a program for testing BSUs and conducting training exercises with all involved parties.
ESKOM (South Africa)	System-wide Assumes no black-start support via interties from adjacent countries.	Top down. ESKOM owns & operates all BSUs. Grid code requires 2 black start *plants* in the national plan a pumped hydro & a large coal plant.	Per Grid Code, all generators over 200 MW must have capability for TTHL for 2 hrs, but they are not used in defining BSU requirements.	Each black start plant must be able to energize a large coal fired plant within 4 hrs.	Tested every 3 years, must energize specified cranking path to large coal plant. ESKOM performs steady-state and transient simulations of black-start plan.
IESO (Ontario, Canada)	System-wide and regional. BSU must be in zone, with no support from adjacent zones during initial restoration.	Top down. At least one BSU is selected per each of four zones.	BSU must have a speed governor that can operate isochronously. Assumes many steam units will be capable of TTHL, but doesn't consider them to be BSUs or rely on them for the restoration plan.	BSUs must energize transmission paths in: ½ hr. hydro & aero-derivative GTs, 1 hr. Industrial/frame GTs, 2½ hrs steam turbines, other types per contract.	Demonstrate BSU can energize designated cranking path and maintain open-end-of-line voltage ≥10 min. BSU must also be able to complete 3 black starts within an 8 hr. period due to likelihood of recollapse during system restoration.

Entity or region	System-wide or regional black-out/interties	Develop top down or bottom up black-start plan	Black-start unit qualifications	Restoration time targets or requirements	Study and/or testing requirements
PJM (US Mid-Atlantic region & westward to Illinois)	System-wide and regional blackouts. Assumes zone ties used for restoration from approved BSUs.	Top down, but PJM seeks input from transmission owners on BSU selection.	Minimum of two BSUs per zone, but BSU can be outside of the zone and a BSU can be shared by multiple zones.	Maximum BSU startup time is 3 hrs. but must supply critical loads* within 4 hrs.	PJM and transmission owners run simulations for proposed BSUs and restoration plans (PJM focuses on 500 kV restoration). BSU's must pass performance test.
Note: * Each zone's "critical load" = (cranking power to all hot-start thermal generators in the zone/sub-network that are capable of starting in 4 hour) + (off-site power supply to nuclear units) + (supply to critical gas compressors.)					
NYISO (New York State)	Not explicitly stated, but infers that black-start plans for upstate region and New York City must stand alone.	Top down for BSUs needed to restore 345 kV backbone grid. Bottom up for transmission owners (TOs).	Existing BSUs remain in plan unless they request contract termination. Additional BSUs added if needed to reduce system restoration times.	Not explicitly stated.	Each TO must file annual black-start study with ISO. ISO reviews and does their own study as needed. BSU's must pass annual performance test to receive compensation.
ERCOT (Texas)	Not explicitly stated, but regional and multi-regional are inferred.	Top down. ERCOT develops plan based on bids received from across the region.	BSUs can be outside of a zone they serve.	Not explicitly stated.	ERCOT performs restoration simulations as part of BSU bid evaluations. Winning BSUs must pass performance test.

5. DNV KEMA findings

DNV KEMA prepared this report by reviewing a wide range of publicly-available documents and selected confidential documents, discussing various aspects of the NEM electric system with AEMO staff, and based on our past experience and engineering judgment. No technical analyses were made other than those described in this report.

5.1 Blackout probability—NEM-wide versus state-wide

The underlying assumption for determining SRAS is now that a NEM-wide blackout occurs. There is no requirement in the NER or SRS to assume such a NEM-wide blackout for determining SRAS. For the years before the Australian electricity systems were deregulated and the NEM formed, each state assumed a region-wide blackout in determining their required black-start needs. The AEMO believes that assuming a NEM-wide blackout is "too conservative" and "highly unlikely" and that the present approach is not justified

In our experience a cascading blackout usually continues until it reaches a transmission break point. Such break points are usually where there is a reduced amount of transmission connecting the "problem area" with the remaining portions of the system. At some point in the cascade, the problem area of the system will be isolated from the rest of the system that has a reasonable load-generation balance.

Based on our review of the NEM transmission system maps and the locations of load and generation, and relying on engineering judgment, we identified the likely transmission break points in the NEM system. Most of these break points are the same as the regional and sub-network boundaries recommended by the AEMO. The one exception was along the Queensland–New South Wales boundary where we suggested a change.

We found that these NEM transmission break points would prevent a spreading blackout and that this assumption made by the AEMO is reasonable and justified.

We identified and discussed the probabilities and extent of various events—accidents, natural disasters, and attacks—that might cause a NEM-wide blackout. We found that there is no credible possibility of an event that could cause a NEM-wide blackout.

5.2 Defining sub-networks

The SRS provides guidelines for the AEMO to determine electrical sub-networks. The SRS allows the AEMO to determine the boundaries for electrical sub-networks without limitation based on the electrical strength of transmission, electrical distance, and load and generation. We find that this definition is adequate for defining sub-networks.

Our review of the NEM transmission system found that the AEMO should consider using a transmission break-point analysis like that presented in the report to define sub-network boundaries. Such a revised approach would likely change the boundaries in New South Wales, but would leave the others unchanged.

5.3 SRAS definition, quantity and assessment

The AEMO proposes eliminating the primary and secondary SRAS categories by defining a single class of SRAS tenders. We agree with this proposal and understand that the SRS will need to be a changed in order to remove the primary and secondary SRAS definitions.

The second change in the SRAS definition is rather than energizing the auxiliaries of a large generating unit, the AEMO proposes energizing a target *transmission* bus in 60 minutes or less. While AEMO's proposed definition improves the likelihood of meeting the SRS' four-hour target, it may increase the uncertainty of meeting the SRS' 90 minute target.

The AEMO's proposal assumes that power can be routed from an SRAS to a large generator's auxiliaries within 30 minutes. In our opinion this seems to be overly optimistic as a general assumption. Therefore, we recommend that the AEMO consider setting a shorter target time for SRAS tenders to energize the closest transmission bus (e.g., 45 minutes).

In addition to reducing the target times for energizing the transmission bus we recommend that the AEMO consider taking certain steps to help ensure that the standard's 90 minute restoration target can in fact be met by "winning" tenders as described in §4.1 on page 54, above.

The AEMO has not performed a detailed technical analysis regarding the minimum size for SRAS resources. It appears the 100 MW minimum rating for SRAS tenders was adopted as a conservative estimate. We believe a smaller SRAS capacity could suffice, subject to suitable technical modeling and verification. We recommend that AEMO consider the pros and cons of relaxing or eliminating the minimum SRAS tender size. As an intermediate step we suggest a reduction to 75 MW allowing more SRAS tender offers making the process more competitive. Regardless of the size of the tender, AEMO's assessment methodology should determine if the tender can meet the functional requirements and targets of the standard.

The AEMO now acquires SRAS from two independent providers in each sub-network based on the assumption that there could be a NEM-wide blackout. The AEMO now proposes a minimum of one SRAS tenders per sub-network based on a revised assumption that interconnectors with neighboring sub-networks will serve as the primary black-start source. We believe this is a reasonable approach that should not degrade NEM reliability.

Since the Tasmanian sub-network only has an HVDC interconnector to its neighbors which is unable to operate during a black start condition, the AEMO proposes keeping the requirement for two independent SRAS tenders in this one sub-network. We also agree with this conclusion.

Relying on powerflow modeling alone, as the AEMO now does, is not enough to confirm a workable black-start plan. The AEMO has advised DNV KEMA that it does not now have access to dynamic or transient data for either the transmission network or generating facilities. We recommend that AEMO investigate the available sources for such modeling data and consider options for performing such modeling in future SRAS tenders.

5.4 Impact of proposed changes

Any changes to the SRAS must meet SRS requirements. As described below we believe that the AEMO's proposed changes meet the technical SRS requirements we have addressed in the report with only the one exception where primary and secondary SRAS are combined.

Regarding NEM-side versus regional blackouts:

- While the AEMO now assumes a NEM-wide blackout in determining SRAS requirement; there is no such requirement in the NER, or SRS;
- The AEMO proposes to use region-wide blackouts as the basis for future SRAS requirements;
- We do not believe there is any credible event that could cause a NEM-wide blackout;
- We also believe there are relatively few events that could cause a region-wide blackout; and
- We, therefore, agree with the AEMO's proposed change.

Regarding sub-network definitions:

- The AEMO proposes to reduce the number of sub-networks from ten to seven;
- We generally agree that the number of sub-networks should be reduced, however, we would combine a revised north New South Wales sub-network with that of south Queensland. This change would further reduce the number of sub-networks to six;
- We believe that the resulting main New South Wales sub-network should have at least two SRAS; and
- We recommend that the AEMO use transmission break points as the basis for determining sub-network boundaries in the future.

Regarding SRAS definitions, quantities and assessment:

- With the present approach, it is possible for an SRAS to be unable to effectively meet the SRS target to serve 40% of peak load within 4 hours;
- We believe the new approach would make it possible for more of the existing black-start resources in NEM to participate in the SRAS tender process, making the process more competitive;
- We believe that the AEMO's proposed changes to SRAS tender requirements and definitions should improve the likelihood of meeting the SRS targets, especially supplying 40% of peak load within four hours; and
- We recommend a more rigorous AEMO technical assessment process for SRAS tenders to improve the likelihood of actually meeting the SRS targets.