27 October 2016

Mr Neville Henderson
Chairman
NEM Reliability Panel
Australian Energy Markets Commission
PO Box A2449
Sydney South NSW 1235

Dear Mr Henderson

RE: Reliability Panel, Review of the System Restart Standard, Draft Determination, 25 August 2016 (REFERENCE: REL0057)

ERM Power Limited (ERM Power) welcomes the opportunity to respond to the NEM Reliability Panel's Draft Determination for the Review of the System Restart Standard. ERM Powers believes that the NEM would be best served by an increased number of geographically diversified System Restart Ancillary Service (SRAS) providers to enable an electrical sub-region to restart as quickly as possible following a *System Black* event regardless of any potential damage to the transmission network or generating units.

About ERM Power Limited

ERM Power is an Australian energy company that operates electricity generation and electricity sales businesses. Trading as ERM Business Energy and founded in 1980, we have grown to become the fourth largest electricity retailer in Australia, with operations in every state and the Australian Capital Territory. We are also licensed to sell electricity in several markets in the United States. We have equity interests in 497 megawatts of low emission, gas-fired peaking power stations in Western Australia and Queensland, both of which we operate.

General comments

In general, ERM Power supports the methodology as proposed by the Panel in the Draft Determination. Notwithstanding our support for the methodology, ERM Power questions the veracity of a number of the key assumptions used in the calculations. Details released both in the Draft Determination and subsequently are of insufficient detail to allow participants to reasonably consider the arguments as set out by the Panel in the Draft Determination. We are also concerned that indications are that the Panel has not sought to independently verify a number of these key assumptions and had relied on one source only for information. ERM Power questions why the Panel did not seek independent verification of the data given the importance of a number of these key assumptions to the cost benefit analysis outcomes

Complexity of the Proposed Standards

ERM Power is concerned by the complexity of the proposed revised standard, in particular the varying restoration requirements between electrical sub-regions and the requirement for the Panel to publish new standards for sub-regions whenever the Australian Energy Market Operator (AEMO) revises the sub-electrical network boundaries or possibly if the costs of SRAS offers were to materially change.

The presentation at the public forum on 21 September 2016 emphasised that the Standard is a procurement and not an operational standard and is purported to cover only Stage 1 of the restoration process – the most transparent of which is the restoration of auxiliary supplies to selected generating units. The Standard is not required to cover the restart of all major power stations in Stage 2 or the load restoration period which occurs in Stage 3.

Notwithstanding, the existing standard is often misinterpreted by many parties such as, jurisdiction and consumers, believing that 45% of load will be restored within 4 hours. The revised Standard if implemented will do little to promote a better understanding for jurisdictions and consumers regarding the restoration of the power system following a *System Black* event. This is an area that the Panel should consider for improvement in the Final Determination and the revised Standard.

Reduction in Level of Service between the Current and Revised Standard

ERM Power also notes that the proposed Standard is in effect a reduction in the level of service provided by the current Standard, from nominally the ability to restore 45% of Peak Load within 4 hours if network capability existed, to a generally much lower nominal percentage of Average Loads within 3 or 4 hours.

The table below sets out a comparison of the existing and revised Standard in MW restoration capability.

Electrical Sub-Region	Current Standard	Revised Standard
North Queensland	1,295 MW	965 MW – 4 hours
Central and Southern Queensland	2,263 MW	937 MW – 3 hours
New South Wales	5,851 MW	1,715 MW – 3 hours
Victoria	4,230 MW	1,157 MW – 3 hours
South Australia	1,360 MW	397 MW – 3 hours
Tasmania	716 MW	355 MW – 3 hours

ERM Power notes that the larger regions appear to be disproportionally impacted in terms of load restoration capability.

Generation Restoration Timeframes

The time to restore generation and hence load is one of the most critical assumptions in the cost benefit analysis. It is from this capability of generators to restore load that the costs of unserved energy is calculated. The restoration curves supplied in the Draft Determination appear overly ambitious and bear little resemblance to historical unit return to service (RTS) outcomes.

ERM Power provided a number of historical return to service outcomes for units following a multi-unit trip scenario in our submission to the Reliability Panel's Discussion Paper. We believe that this historical information contains key information to the Panel that may not have been well understood by Panel members and Australian Energy Market Commission (AEMC) staff, particularly in relation to generator restoration capability in the event of a *System Black* scenario.

When multiple units have tripped out of service, generation participant's staff are highly focused on returning the units to service as quickly as possible, achieving the maximum amount of output that can safely be achieved at any given time within the RTS process. It is also worth noting, that for these historical scenarios, units were being returned to service into a stable and secure power system, and as such, unit output was not constrained by any external factors. Therefore it can be confidently interpreted by the Panel from the historical data that units achieved their maximum capability that was possible at any given point in time.

It is highly probable that as secure auxiliary power supplies remained available, or were available within a very short timeframe to the returning units during these historical RTS scenarios, this data represents the absolute best that can be expected and generation restoration following a real *System Black* event will invariably be worse than these outcomes. Delays to restoration of auxiliary power supplies during stage 1 of the restoration process due to minimisation of SRAS contracting will invariably lead to additional delays in unit restoration timeframes for the larger coal fired units due to turbine cooling issues. A delay of one hour in Stage 1 could result in a 2 hour, or longer delay, in Stages 2 and 3.

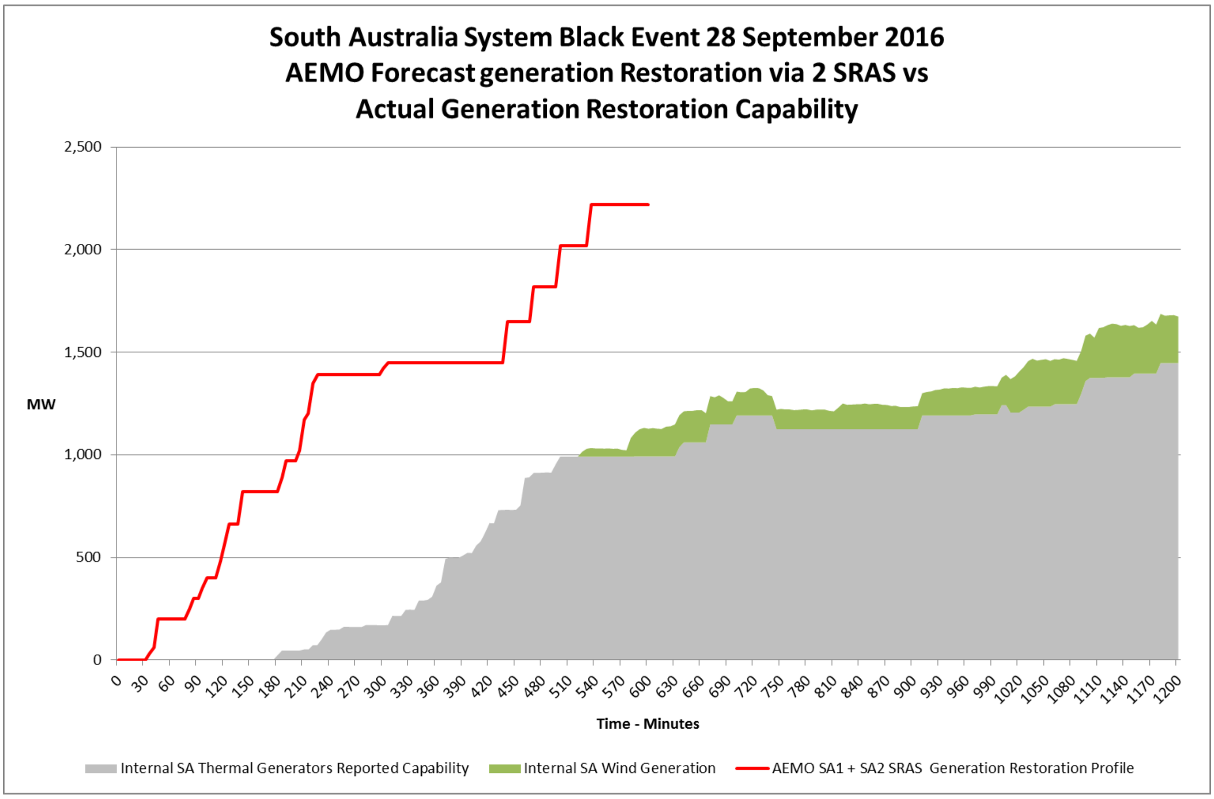
To assist the Panel members and Commission staff, ERM Power has again included this historical information - Appendix A, and included an additional multi-unit trip event on 8 June 2016 at Yallourn. This new event follows a similar RTS profile as the earlier events.

ERM Power in Appendix B has also included a history of the average time to return a single unit to service following an unplanned unit trip. The data is based on the entire NEM history and has been recorded only for units where return to service activities commenced promptly and proceeded with only normal physical plant related return to service delays. Units that experienced a significant plant failure event that delayed return to service were not included in this record.

All this historical RTS data is very much at odds with the input data assumptions used by the Panel and the AEMC in the Draft Determination and clearly highlight there is a significant difference between actually achieved historical generation restoration outcomes and what appears to be overly ambitious restoration profiles used for the economic analysis in the Draft Determination.

Given the System Black event in South Australia on 28 September 2016, please find below a comparison based on publically available data supplied to the Market by AEMO of the actual restoration of generation capability vs the generation restoration profile for SA1 plus SA2 SRAS for South Australia which has been used to support the conclusions in the Draft determination. The SA1 plus SA2 SRAS restoration profile has been selected as AEMO's advice to the Market following the *System Black* declaration was that the System was being restored using 2 SRAS.

It should be noted that generation output in the following graph reasonably represents the capability of the generators to supply load in South Australia during the system restoration process. The data presented in the graph is based on generation bid availability and not on AEMO dispatch targets, they are therefore free of any external constraints applied to South Australian generation during the RTS process. Examples of this bid and unit dispatch data are presented for the Panel's reference in Appendix C.



As the Rules require restoration to be achieved solely by the use of generation capability within the electrical sub-region, the preceding graph does not contain details of interconnector capability. Insufficient data exists in the Draft Determination to determine if the generation capability restoration curves used in the economic analysis include interconnector capability. If that is the case, we question if this is Rules compliant.

It is critical that the generation restoration curves used in the cost benefit analysis recognise one of the major practical elements in generator restoration; that is, generators cannot simply instantaneously step change in output to achieve a theoretical outcome. Simply having a generating unit resynchronised does not mean it can supply load up to its maximum bid capability, at that point in time, and historical return to service profiles provide a valid history of generator restoration capability. Historically it may require 1 to 3 hours to run a large coal fired unit up from the point where it has just resynchronised to achieving full output due to the normal physical plant challenges routinely encountered during a unit RTS, and that is in a stable and secure power system. It is probable that the generator capability data represented in the above graph overstates true generator capability during some points of the restoration process as in most Dispatch Intervals (DI's) generators were not required to dispatch to this reported capability and therefore issues that may have otherwise occurred when attempts were made to dispatch to higher load remained hidden.

The South Australian *System Black* event also highlights the potential significant value of multiple geographically diverse restart services, in particular given that historically these types of events involve multiple failures on transmission network elements and generators, some of which may be a designated restart service.

Application of a Time Limit (T_{max}) and Impact on the Cost Benefit Analysis

ERM Power believes the arbitrary limit of 10 hours maximum restoration timeframe (T_{max}) applied to generator and load restoration timeframes artificially limits the analysis and potentially understates the cost of a *System Black* event and therefore the benefits which are achieved by the provision of additional SRAS. We understand that the Commission has applied this arbitrary limit as it reflects the time following which remote operation of transmission switchyards may not be possible.

However, the Draft Determination acknowledges that local manual operation at the switchyards remains technically achievable, albeit requiring a longer timeframe for the Network Service Provider staff to attend unmanned switchyards[1]. Given that local operation remains technically achievable we question the need for any artificial time limit for the restoration process.

ERM Power believes that additional and geographically diversified SRAS providers will assist the power system to achieve actual restoration within the timeframe required to allow ongoing remote operation of the switchyards during the system restoration process.

Adjusted Value of Customer Reliability (VCR) Values

ERM Power notes that the VCR values used in the cost benefit analysis decrease as the outage duration extends. ERM Power believes that for many consumers this would seem to be counter intuitive.

In particular, for residential and small to medium enterprise load the VCR would remain relatively constant and may actually increase with length of outage duration to take into account loss of water supply and sewage systems, increasing difficulties in transport logistics and food spoilage.

A longer duration outage may also result in consumers taking steps to ensure future supply reliability by installing backup power supplies, such as battery storage or standby generators, at considerable cost, whereas for a shorter outage duration, this may not be the case.

ERM Power notes that media commentary by a number of economists suggests that the economic costs of the recent South Australian *System Black* event is in the range of $2 to $5 billion, compared to an estimate of $450 to $550 million calculated using AEMO published market data, the adjusted VCR values and the methodology used in the Draft Determination economic analysis. This appears to be a very large discrepancy.

ERM Power believes the Panel should reconsider the use of adjusted VCR values that decrease with time in the cost benefit analysis.

Aggregate Reliability of Restart Services

ERM Power is concerned that the Panel in the Draft Determination and at the forum was unable to provide attendees with a detailed explanation regarding the methodology used for calculation of this measure. We are also concerned that input assumptions for the calculation, in particular the application of a 95% average availability for all restart services is unreasonably high.

Discussions of examples during the Forum were very helpful but raised more questions rather than providing answers.

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[1] AEMC System Restart Standard Draft Determination page 14

By way of example, please consider a restart service provided by an independent auxiliary diesel generator or gas turbine (GT), with self-start capability used to restart a larger coal fired or combined cycle gas turbine generating unit. An outage of either component of the SRAS would render the SRAS inoperable. To achieve a combined availability of 95%, both services would need to have individual availabilities of at least 97.5%. Compared to historical outcomes this appears to be a very highly ambitious outcome for this type of plant.

ERM Power is also concerned that a number of regions are now serviced for SRAS by *Trip To House* (TTH) services. Our understanding is that there is a view that TTH capability has close to 100% probability of success on at least one unit within the contracted power station.

Given that international experience is that only 25-30% of TTH units which are actually armed at the time for providing TTH services actually succeed when required to do so during a real *System Black* event[2], the allocation of a 95% average availability for all TTH restart services is therefore questionable. This would be particularly the case when the TTH SRAS is contracted with a two unit or single unit power station. We believe that simply arming a unit does not equate to the unit being available for SRAS, and that the number of units actually armed multiplied by the potential to achieve a successful TTH is a more accurate value.

We believe additional work needs to be undertaken to substantiate the very high 95% average availability for all restart services used in this calculation or alternatively this figure should be lower to match average historical generator availability figures and the potential for a TTH service to actually succeed.

We understand that the proposed 90% standard in the Draft Determination for SRAS aggregate required reliability seeks to calculate the probability that at least one SRAS will be available to restart the power system in any electrical sub-region if required to do so.

We agree that this setting is a valuable inclusion in the revised Standard. However, in setting the standard at 90% the Panel has determined that for 10% of the time, or 876 hours in any 12 month period, the electrical sub-region can be without its own independent SRAS.

This represents a large number of hours where an electrical sub-region will be reliant on inter-regional network capability, which may or may not be available, from an adjacent electrical sub-region for system restart capability. We believe that the majority of consumers would require a higher level of certainty of dedicated restart capability than the proposed 90% and urge the Panel to reconsider a higher value of 95 to 99%.

Physical Location of Restart Service

ERM Power believes the physical location of a restart service can be of critical consideration under some scenarios. Times to energise network elements, even if they remain available, from a SRAS in a distant location should be considered and form part of the cost benefit analysis when selecting the number of SRAS. We consider that the Panel's requirement for contracting of at least one SRAS provider in the area of NSW north of Sydney to be a very prudent additional requirement in the proposed System Restart Standard. However, we believe it would be of greater benefit to consumers if two electrical sub-regions were designated for NSW. This would ensure a balance of load restoration across all NSW rather than currently, where load restoration could be focussed in the southern areas of NSW to the detriment of consumers in northern NSW and still comply with the Standard.

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2 DG Consulting report to the AEMC Reliability Panel - International Comparison of Major Blackouts and Restoration (May 2016)

ERM Power believes there are other electrical sub-regions which would benefit from a similar locational SRAS determination.

Comparison to International Events and SRAS Standards

ERM Power is concerned that a number of the *System Black* events examined by the Panel relate to power systems which have little resemblance to the generation mix and transmission network topography of the Australian National Electricity Market (NEM). In fact, the DGA Consulting report – International Comparison of Major Blackouts and Restoration (May 2016) contains little details regarding generation mix or transmission network topography.

Of the events contained in the DGA Consulting report, it is possible that only the events in the Eastern United States in 2003 roughly translate with reasonable correlation to the NEM.

ERM Power believes that there is a high probability that a power system comprised primarily of hydro and gas fired turbines would return to service more quickly and with less operational difficulties than the NEM. Therefore we believe the Panel should seek to provide additional clarity with regards to generation mix in the nominated comparisons. In particular, the types of generation used for SRAS as well as the mix of generation installed and transmission network layout used in each of the power systems that have been cited as an international comparison, so as to allow participants and consumers to better understand the correlation to the NEM of the events included in the DGA Consulting report.

AEMO's Power of Direction

It is uncertain if the achievement of the generator restoration profiles provides for the use of AEMO's power of Directions to utilise additional SRAS sources rather than only that procured under contract. ERM Power believes that as the System Restart Standard is a procurement standard only and not an operational standard, then the assumptions regarding the issue of Directions by AEMO to achieve the generation restoration curves should be transparent. Given it is a procurement standard only, we believe the possible reliance on AEMO's power of Direction to achieve the generator restoration profiles fails to align with the intent of the Standard and the SRAS procurement process.

Please contact me if you would like to discuss this submission further.

Yours sincerely,

[signed]

David Guiver
Executive General Manager - Trading
07 3020 5137 – dguiver@ermpower.com.au

Appendix A: MULTIPLE UNIT TRIP AND RESTORATION EVENTS

Event 1 – Friday 13 August 2004

Bayswater Units 1-3

Vales Point 6

Eraring 2

Under Frequency Load Shedding of approx. 2,000 MW across multiple regions

At the time of the trip system load was in decline and the system demand at the time of the event was approx. 80% of the peak system demand that day.

Auxiliary power was not lost to the units at the time of the trip or during the restoration process

Time to resynchronise the units

VP6 – 6 hrs

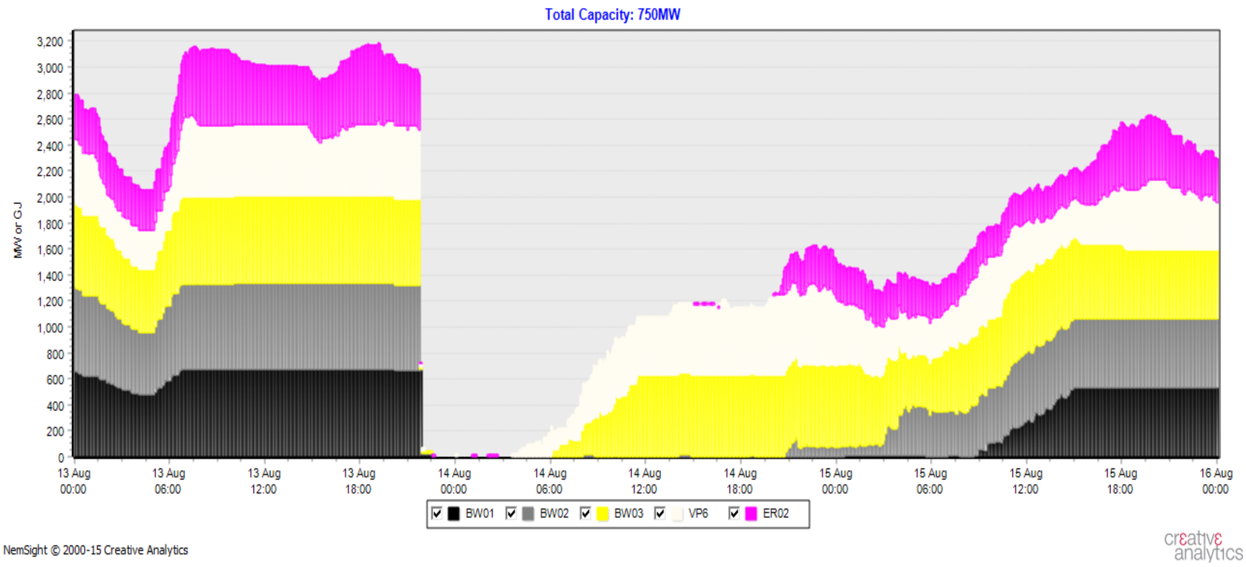
BW3 – 8 hrs

BW2 – 23 hrs

ER2 – 23 hrs

BW1 – 35 hrs

In addition to the time to resynchronise an additional period of 3.5 to 7 hrs was required to ramp units to achieve minimum stable loading



Event 2 – Thursday 2 July 2009

Bayswater Units 1 – 4

Mt Piper 2 – the unit was in the process of returning to service at the time of the multi-unit trip at BW and had not as yet achieved stable minimum loading. The unit tripped from 231 MW

Under Frequency Load Shedding of approx. 1,000 MW across multiple regions

At the time of the trip system load was in decline and the system demand at the time of the event was approx. 96% of the peak system demand so far that day.

Auxiliary power was lost to the BW units at the time of the trip and a time delay of approx. 20 minutes occurred before the restoration process could commence

Time to resynchronise the units

BW1 – 4 hrs

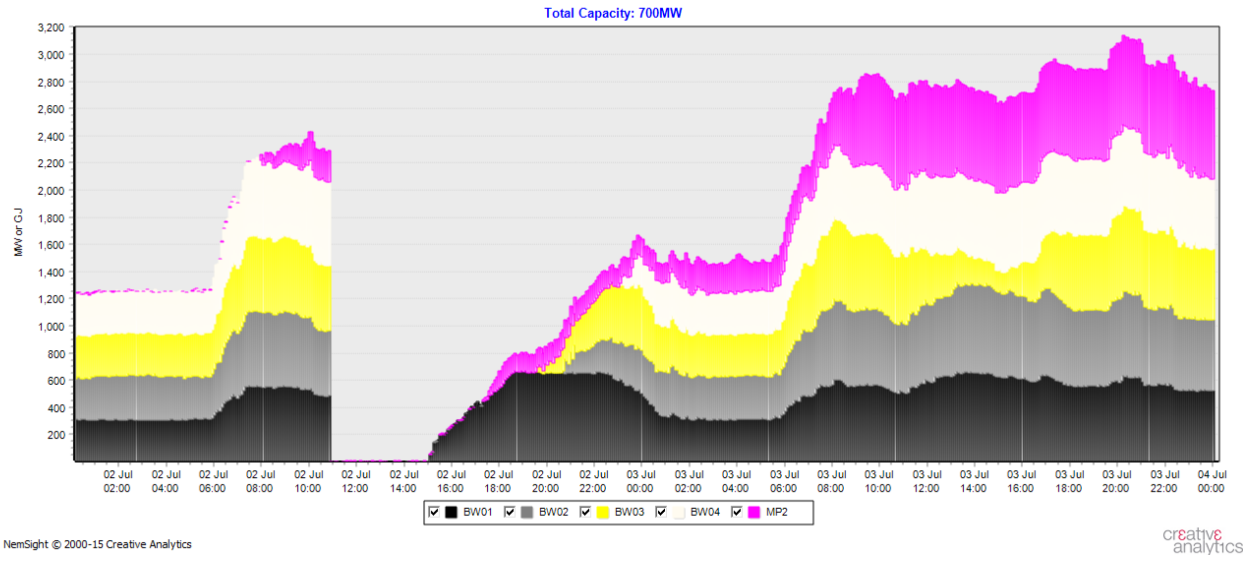
MP2 – 6.5 hrs

BW3 – 8.5 hrs

BW2 – 9.5 hrs

BW4 – 12 hrs

In addition to the time to resynchronise an additional period of 2 to 3 hrs was required on the BW units to ramp units to achieve minimum stable loading



It should be noted that at the time of this event a full shift of additional operating staff were involved in a Training Day at site and were immediately available to assist with the return to service of the units.

Event 3 – 19 June 2012

Loy Yang A Units 1, 3 and 4

Under Frequency Load Shedding of approx. 700 MW across multiple regions

At the time of the trip system load was in decline and the system demand at the time of the event was approx. 89% of the peak system demand that day.

Auxiliary power was not lost to the units at the time of the trip or during the restoration process

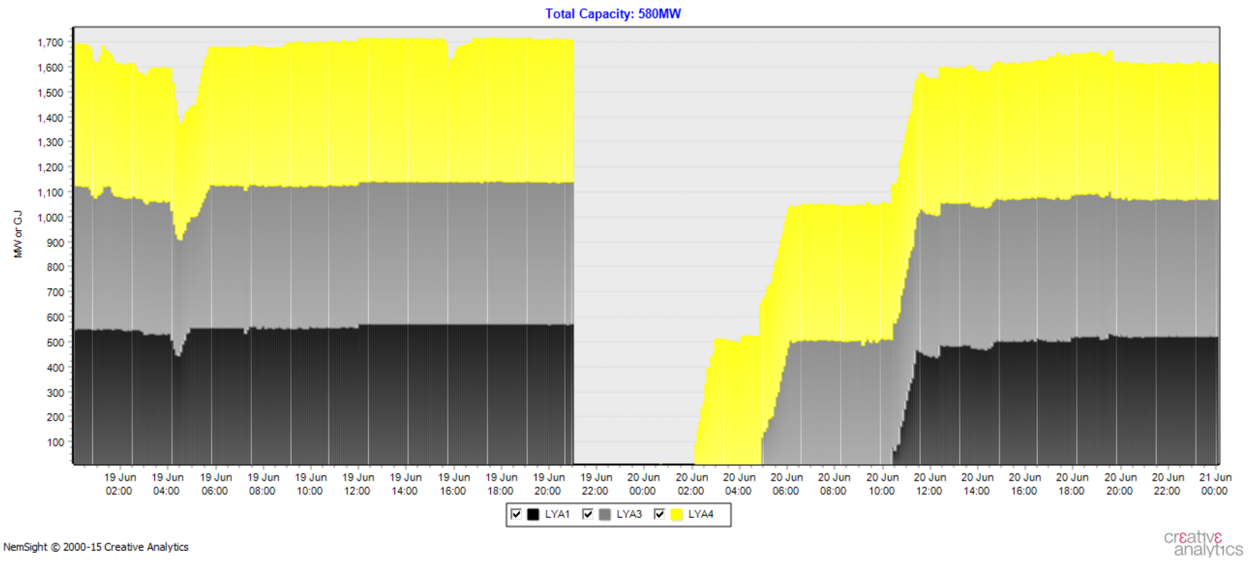
Time to resynchronise the units

LYA4 – 5.25 hrs

LYA3 – 8 hrs

LYA1 – 13.5 hrs

In addition to the time to resynchronise an additional period of 0.5 hrs was required to ramp units to achieve minimum stable loading



Event 4 – 6 March 2009

Callide C3 and C4

Whilst both units did not trip simultaneously, the unit trips occurred within a 15 minute timeframe and the RTS of the units occurred simultaneously

Under Frequency Load Shedding did not occur

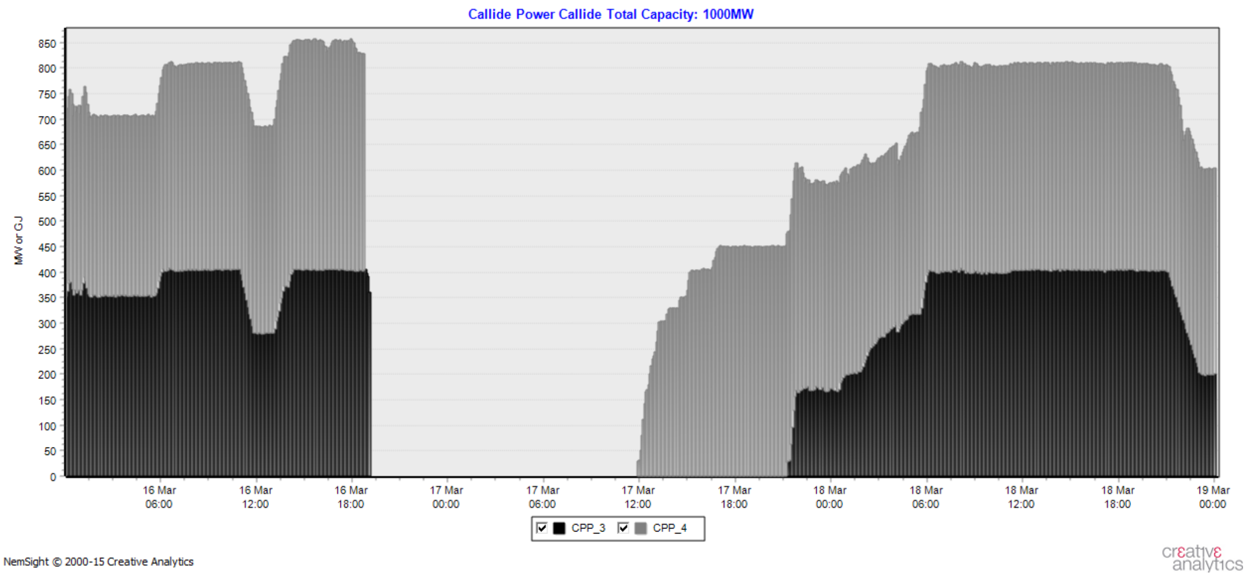
Auxiliary power was not lost to the units at the time of the trip or during the restoration process

Time to resynchronise the units

Callide C4 – 18 hrs

Callide C3 – 26 hrs

In addition to the time to resynchronise an additional period of 1.5 to 5 hrs was required to ramp units to achieve minimum stable loading



Event 5 – 8 August 1997

Yallourn Units 1 - 4

Under Frequency Load Shedding of approx. 1,000 MW across multiple regions

At the time of the trip system load was in decline and the system demand at the time of the event was approx. 90% of the peak system demand so far that day.

Auxiliary power was lost to the YW units at the time of the trip and a time delay of approx. 30 minutes occurred before the restoration process could commence

Time to resynchronise the units

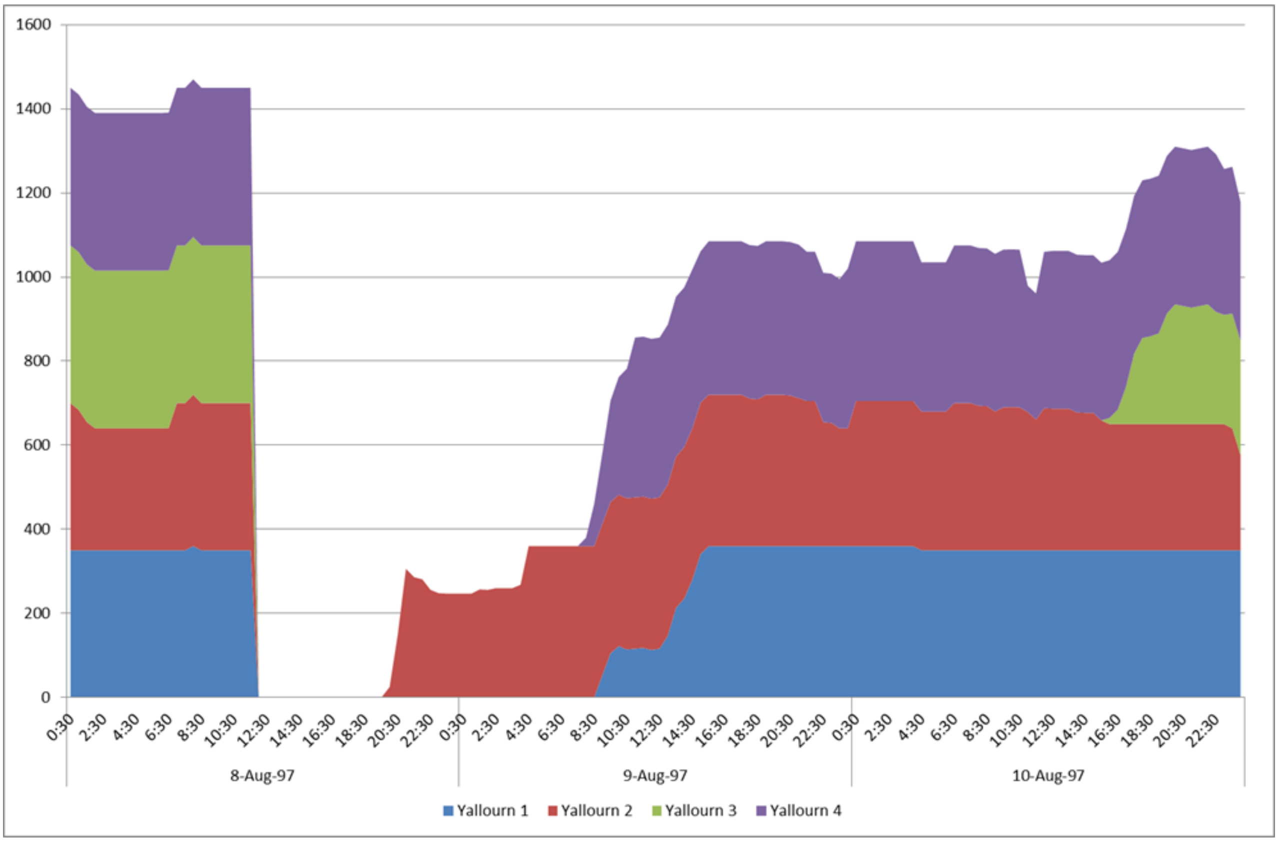
YW2 – 8 hrs

YW4 – 20 hrs

YW1 – 21 hrs

YW3 – 52 hrs

In addition to the time to resynchronise an additional period of 1 to 4.5 hrs was required on the YW units to ramp units to achieve minimum stable loading



Event 6 – 23 December 2013

Millmerran Units 1 and 2

No noticeable Under Frequency Load Shedding was observed

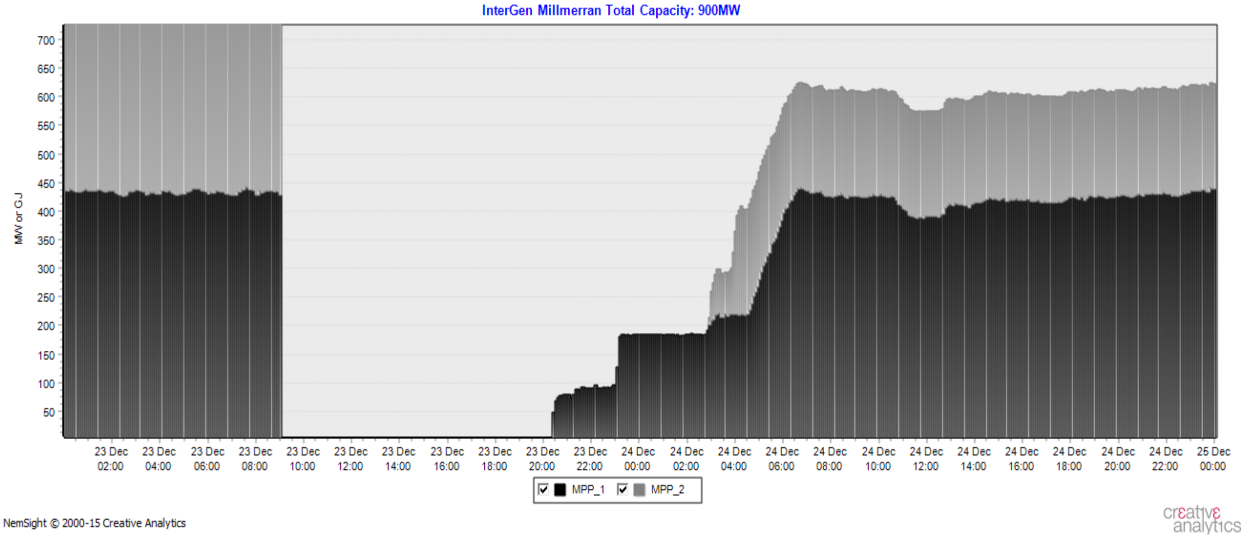
Auxiliary power was not lost to the units at the time of the trip or during the restoration process

Time to resynchronise the units

Millmerran 1 – 11.5 hrs

Millmerran 2 – 18 hrs

In addition to the time to resynchronise an additional period of 1.5 to 2.5 hrs was required to ramp units to achieve minimum stable loading



Event 8 – 8 June 2016

Yallourn Units 1, 2 and 3

Unit 3 tripped approx. 01:30 due to a fault on the No. 2 220 KV Bus

Units 1 and 2 tripped shortly after Unit 3

Unit 4 remained in-service as it is connected to the No.1 220 KV Bus only

RTS of the units was initially attempted simultaneously

Under Frequency Load Shedding did not occur, most likely due to the time at which the event occurred

Auxiliary power was lost for a short period < 15 minutes to the units at the time of the trip but was fully available during the restoration process

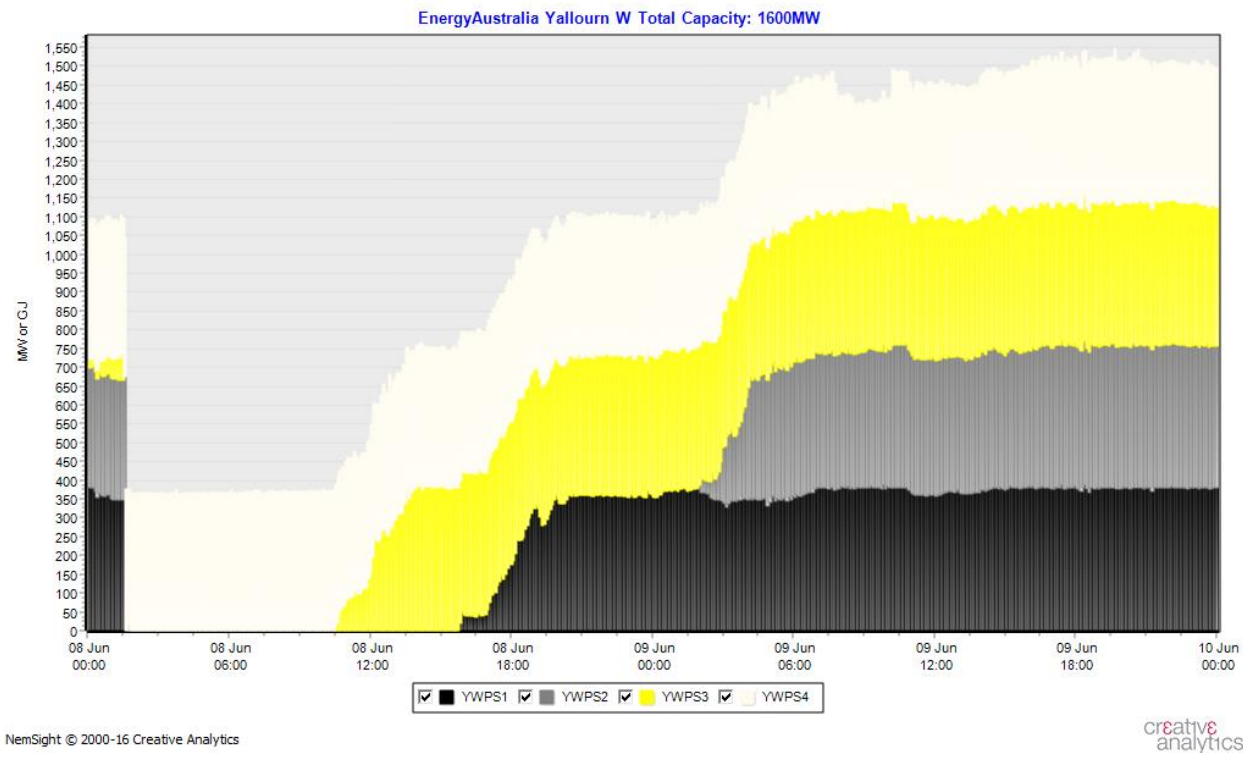
Time to resynchronise the units

Yallourn 3 – 9 hrs

Yallourn 1 – 14.25 hrs

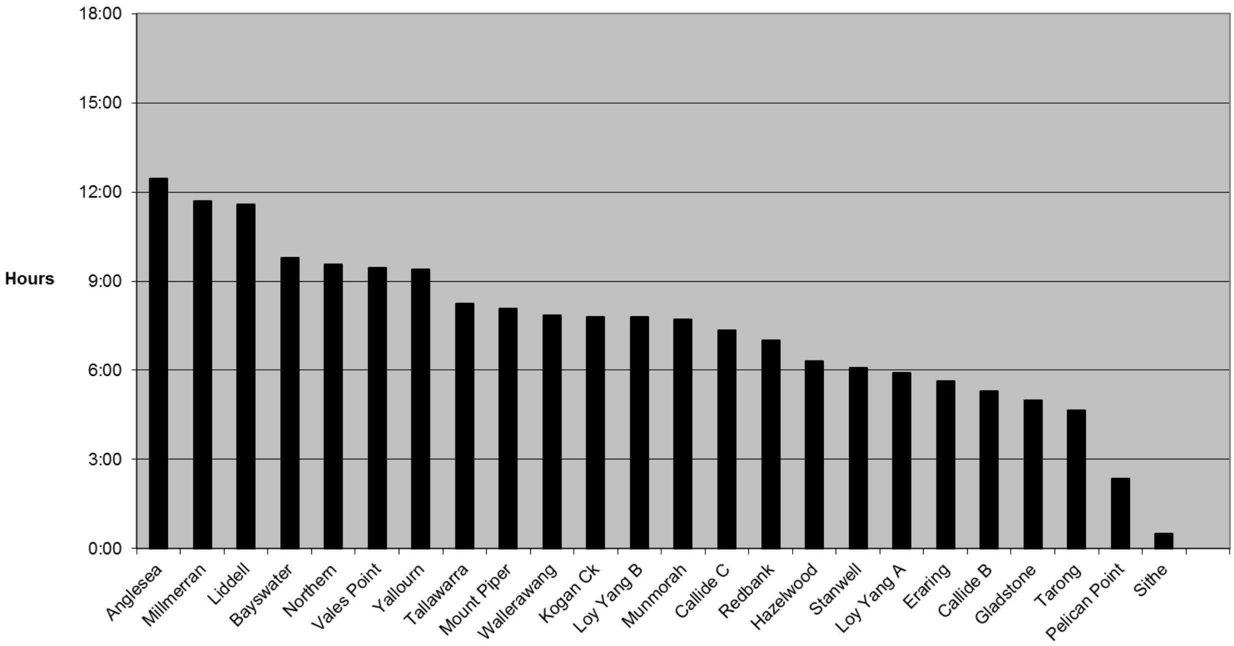
Yallourn 2 – 24.5 hrs

In addition to the time to resynchronise an additional period of 2 to 2.25 hrs was required for the units to achieve minimum stable loading



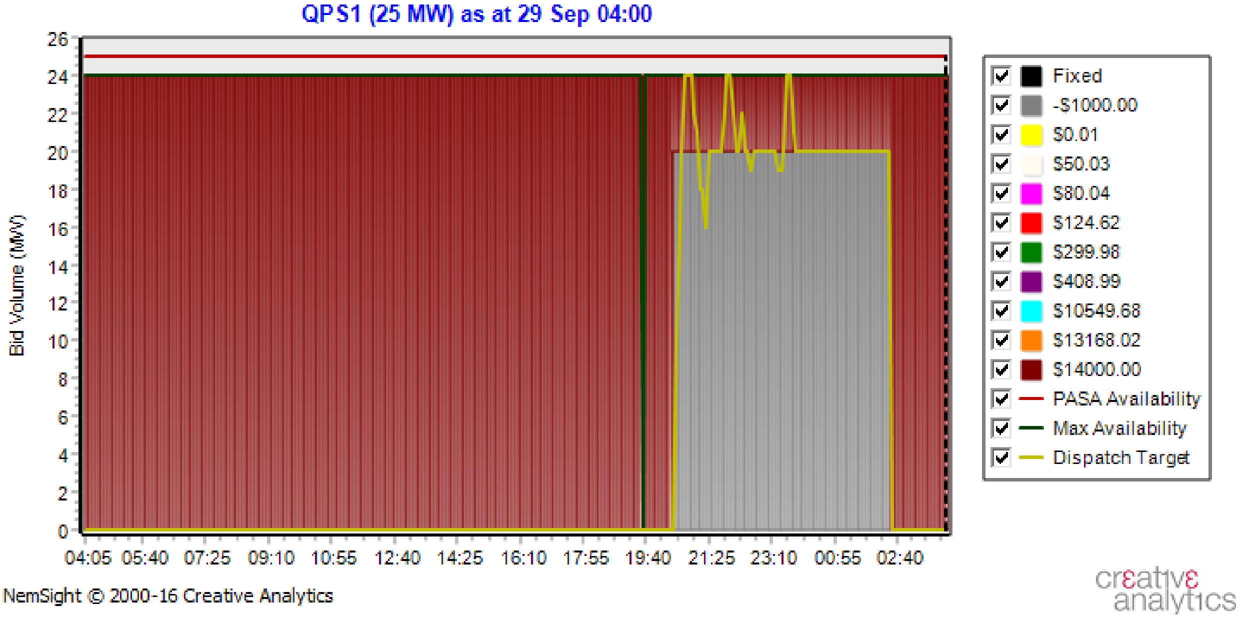
Appendix B: Historical Unit RTS Times Following a Single Unit Trip with Normal Level of Return to Service Complications

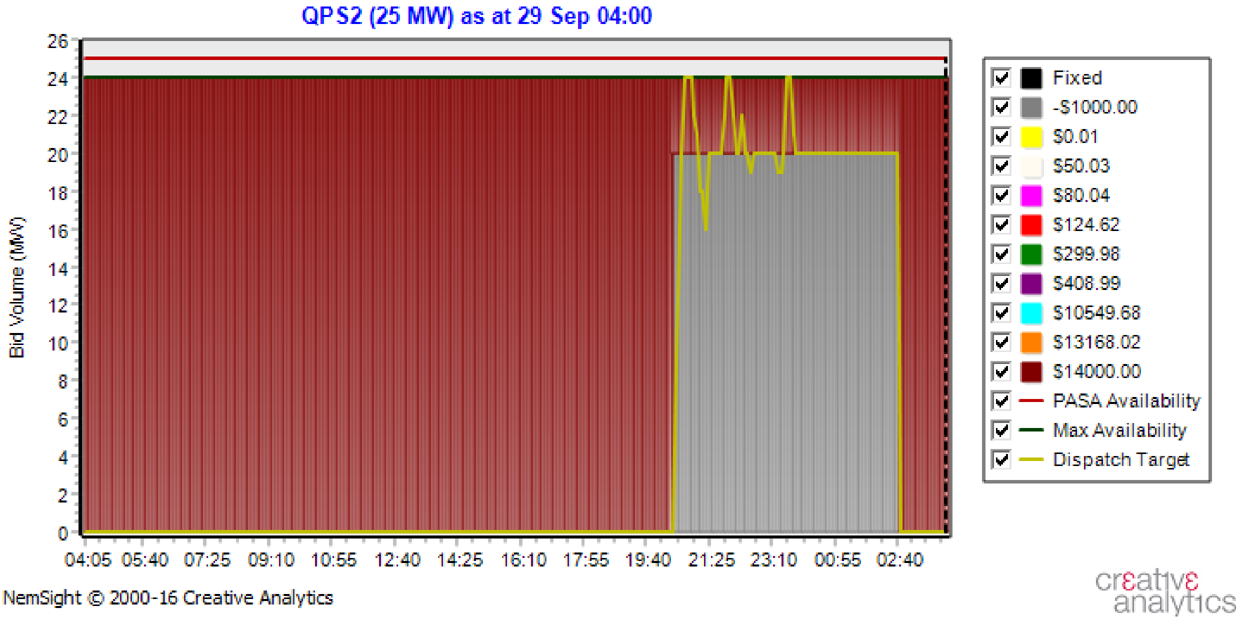
Note Auxiliary power supplies remained supplied to the unit following the trip

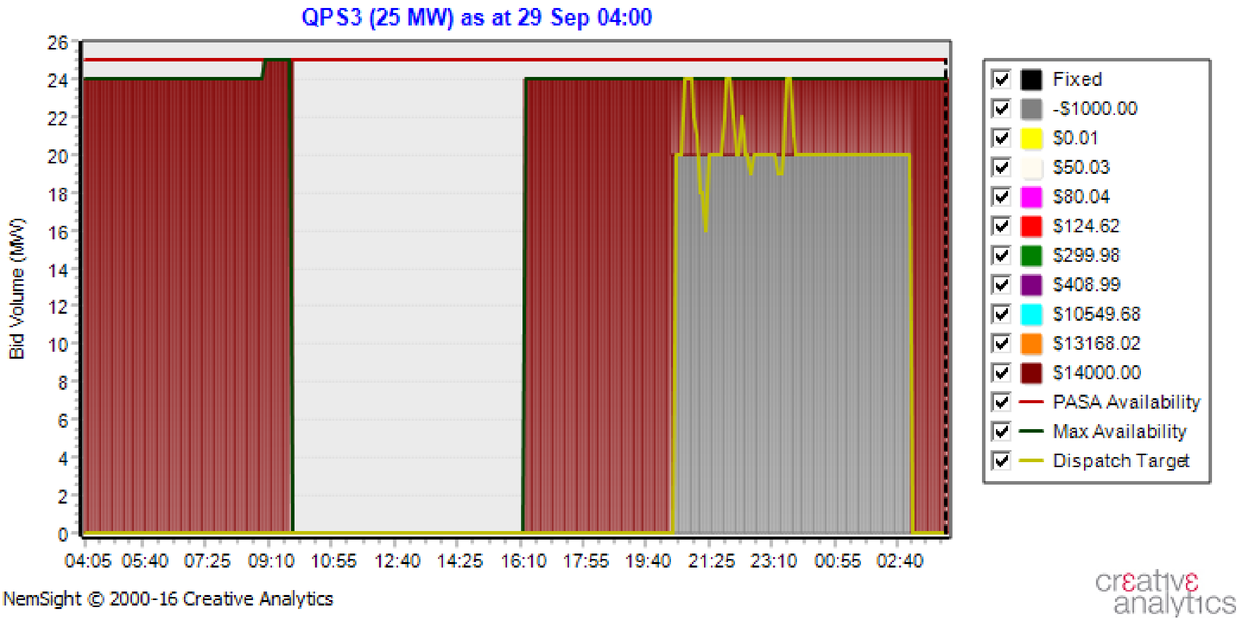


Appendix C: South Australian Generators

Bid Availability and Dispatch Targets during South Australia System Restoration 28 and 29 September 2016






QPS3 (25 MW) as at 29 Sep 04:00
Bid Volume (MW)
04:05 05:40 07:25 09:10 10:55 12:40 14:25 16:10 17:55 19:40 21:25 23:10 00:55 02:40
Fixed
-$1000.00
$0.01
$50.03
$80.04
$124.62
$299.98
$408.99
$10549.68
$13168.02
$14000.00
PASA Availability
Max Availability
Dispatch Target
NemSight © 2000-16 Creative Analytics
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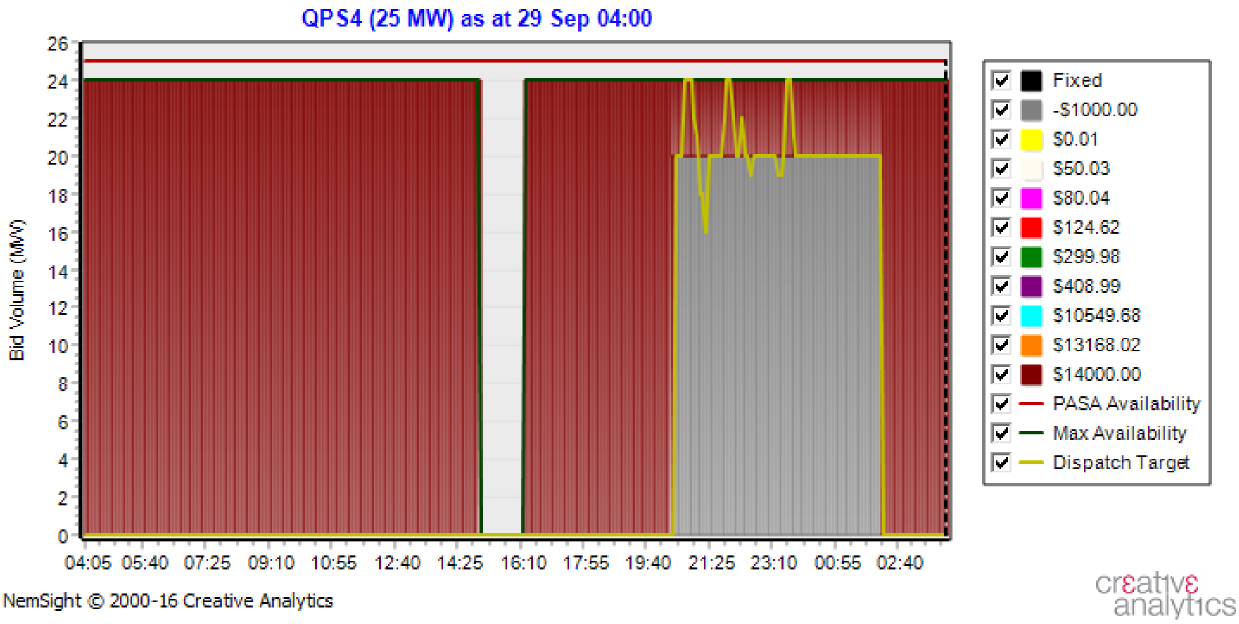
QPS4 (25 MW) as at 29 Sep 04:00
Bid Volume (MW)
04:05 05:40 07:25 09:10 10:55 12:40 14:25 16:10 17:55 19:40 21:25 23:10 00:55 02:40
Fixed
-$1000.00
$0.01
$50.03
$80.04
$124.62
$299.98
$408.99
$10549.68
$13168.02
$14000.00
PASA Availability
Max Availability
Dispatch Target
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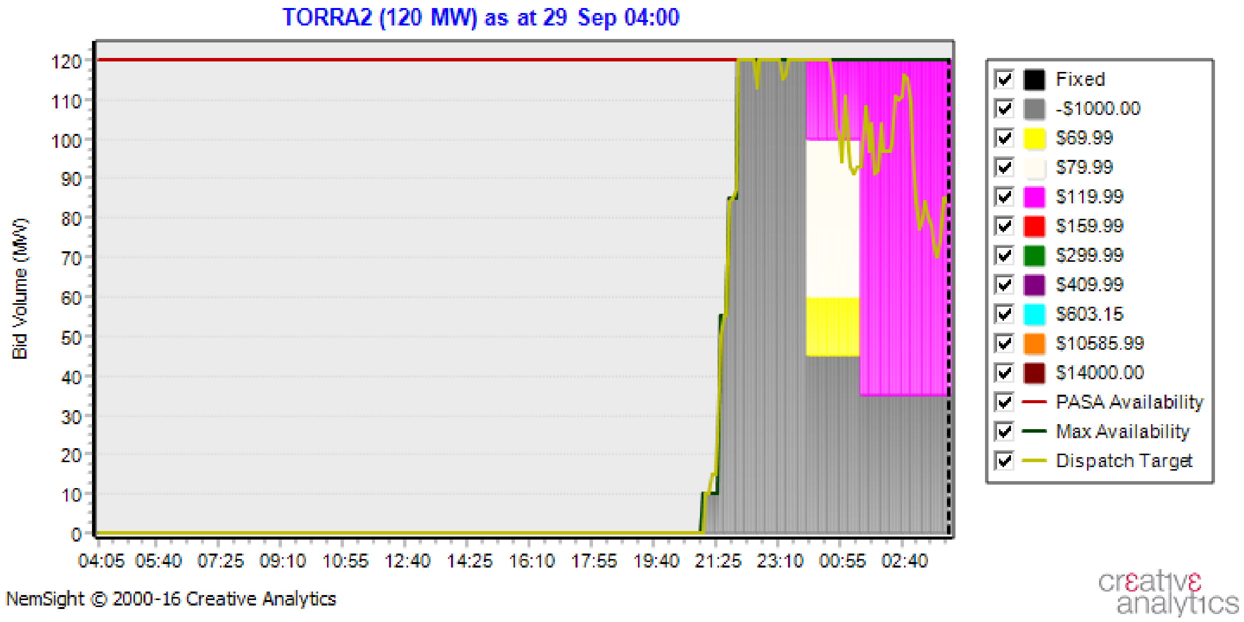
TORRA2 (120 MW) as at 29 Sep 04:00
Bid Volume (MW)
120
110
100
90
80
70
60
50
40
30
20
10
0
04:05 05:40 07:25 09:10 10:55 12:40 14:25 16:10 17:55 19:40 21:25 23:10 00:55 02:40
Fixed
-$1000.00
$69.99
$79.99
$119.99
$159.99
$299.99
$409.99
$603.15
$10585.99
$14000.00
PASA Availability
Max Availability
Dispatch Target
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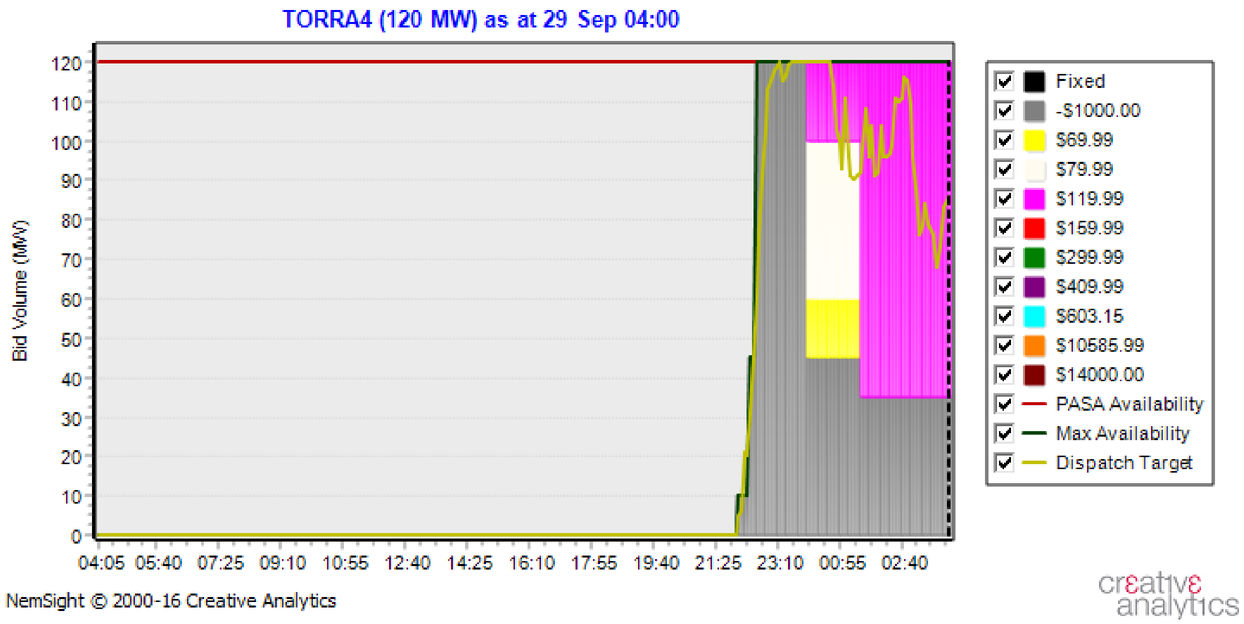
TORRA4 (120 MW) as at 29 Sep 04:00
Bid Volume (MW)
120
110
100
90
80
70
60
50
40
30
20
10
0
04:05 05:40 07:25 09:10 10:55 12:40 14:25 16:10 17:55 19:40 21:25 23:10 00:55 02:40
Fixed
-$1000.00
$69.99
$79.99
$119.99
$159.99
$299.99
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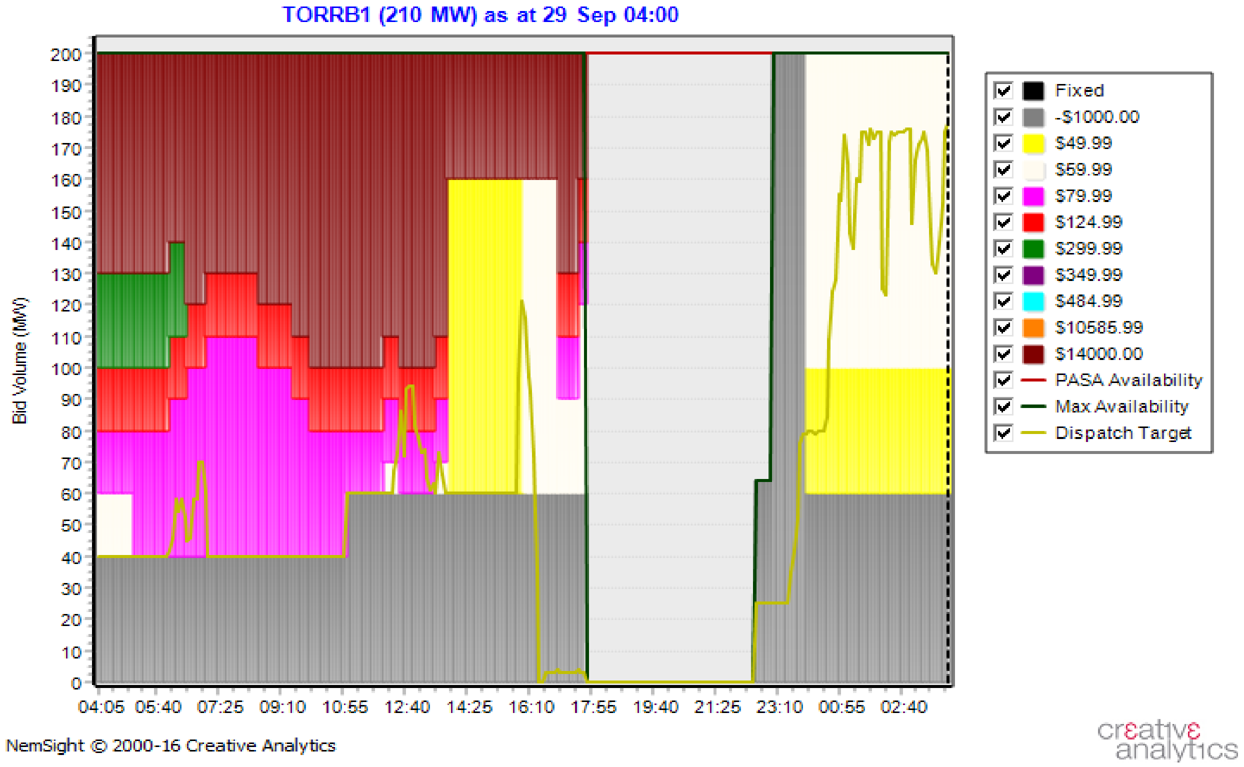
TORRB1 (210 MW) as at 29 Sep 04:00
Bid Volume (MW)
04:05 05:40 07:25 09:10 10:55 12:40 14:25 16:10 17:55 19:40 21:25 23:10 00:55 02:40
Fixed
-$1000.00
$49.99
$59.99
$79.99
$124.99
$299.99
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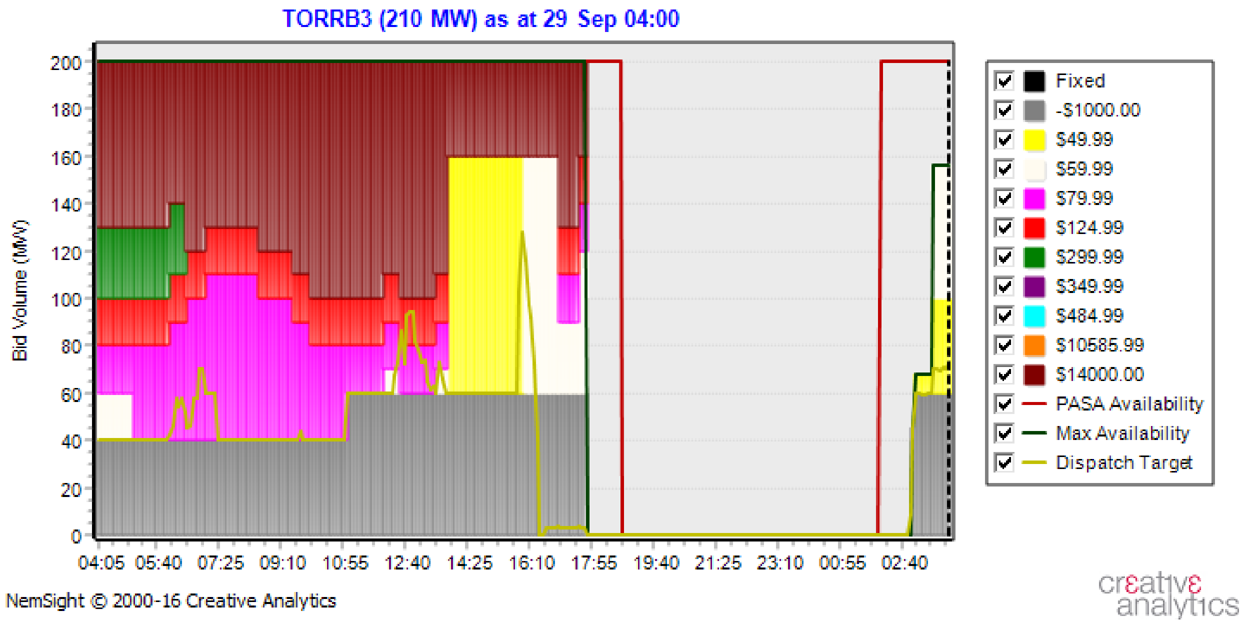
TORRB3 (210 MW) as at 29 Sep 04:00
Bid Volume (MW)
04:05 05:40 07:25 09:10 10:55 12:40 14:25 16:10 17:55 19:40 21:25 23:10 00:55 02:40
Fixed
-$1000.00
$49.99
$59.99
$79.99
$124.99
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$484.99
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PASA Availability
Max Availability
Dispatch Target
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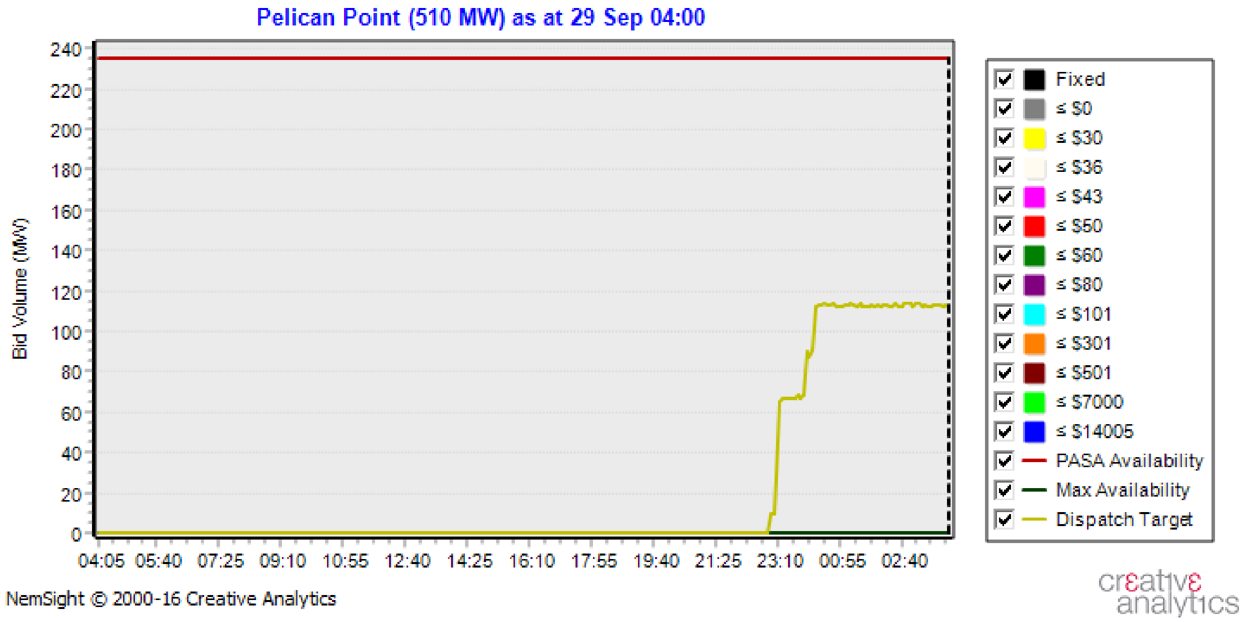

Note: For Pelican Point whilst bid availability indicated 0 MW a figure of 240 MW was used to compile the generation capability restoration profile provided earlier in this submission following RTS of the unit and achievement of 110 MW of output.