Submission to FPSS

Pacific Hydro

16 September 2016

Pacific Hydro
Level 11, 474 Flinders Street Melbourne Victoria 3000 Australia | Telephone +61 3 8621 6000 | Facsimile +61 3 8621 6111 | pacifichydro.com.au

Table of Contents

1. Response to FPSS

The FPSS report is based on analysis that has been performed by AEMO and ElectraNet over the past four years. The analysis reports that underpin the issues in the FPSS, raise questions regarding the modelling used in those studies. The assumptions which have been relied on are documented in the 2013 technical capabilities report. The results in the 2014 report are not transparent and fail to appropriately describe the power system limits which should have been identified within the studies. It is difficult for the reader to arrive at the same conclusions that have been drawn by the author/s as there is insufficient study data and power system results provided in the reports. In this manner the reports fail to justify the actions taken, many of which are excessive and inappropriate.

In brief the 2014 report can be seen as the dynamic studies which underpin the later reports, thereby continuing the shortcomings in the 2014 report. The 2016 report extends the conclusions and thinking propagated in the 2014 report. The 2015 report provides analysis on the variability of the wind energy within South Australia. This shows that from a power system control point of view, the wind power for the majority of the time causes a small actual variability on the power system. For example, this is no greater than mining loads, or rolling mills.

This paper highlights some of the shortcomings presented in the Future Power System Security report and concludes that inappropriate emphasis is being placed on certain issues while other pressing issues are not addressed.

1.1 Frequency Control

It is obvious when all synchronous units are off within a region that the frequency control would be lost following separation. What is unclear and unexplained in the reports is what synchronous units (or inertia) are required to be operational within the region for various interconnector flows or how AEMO have arrived at the constraints that have been implemented. The 2014 Wind Integration Report states that the region has operated with as low as four units on but it does not provide any guidance regarding the power system stability limits for how many units are required for the region to survive the loss of various flows on the interconnector. AEMO have adopted an unexplained approach to the management of South Australia claiming that on separation the regional rate of change of frequency must be within 1Hz/s.

The V-S_RoCoF constraint has been invoked and is binding in the dispatch engine from time to time, but the reason for this 1 Hz/s limit is unexplained other than a belief that the NER minimum standard means older plants might not. The constraint appears to hold the interconnector import flow to up to or about 250 MW, which would place the import limit back to what it was at the start of the NEM and undermines the reasons for the recent upgrades. Figure 1 is derived from public data.

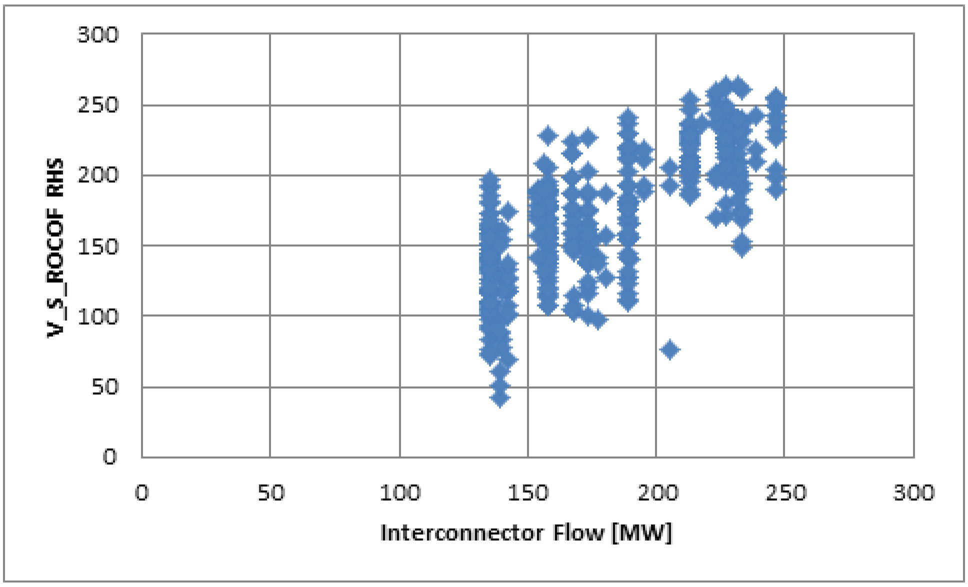

Figure 1: Interconnector Flow for V_S RoCoF

Past system events inform us that the rate of change of frequency for large system events can be higher than 1 Hz/s and that the region has survived. In March 2004 following an auto reclosure onto a persistent fault, the Northern Units tripped to house load causing a power swing event that separated the state. The rates of change in this event illustrate the effect of higher than 1 Hz/s response within the region. Furthermore, no units were switched to AGC control until 11:50 which is well after the separation event and shows that AGC is not critical to controlling the regions' frequency. What is critical is having sufficient synchronous units operating.

The first frequency event in Figure 2 below is from the 2004 separation incident[i]. The frequency record is from high speed event data, the second event in 2005(Figure 3) is provided from EMS data which has insufficient sampling to appropriately illustrate the rate of change of frequency or the sequence of separation adequately. Both events illustrate relatively high rates of change and both occurred at a time when there was only a fraction of the wind power that the state has today. Recent separation events have been around 0.5Hz/s or less in terms of rate of change.

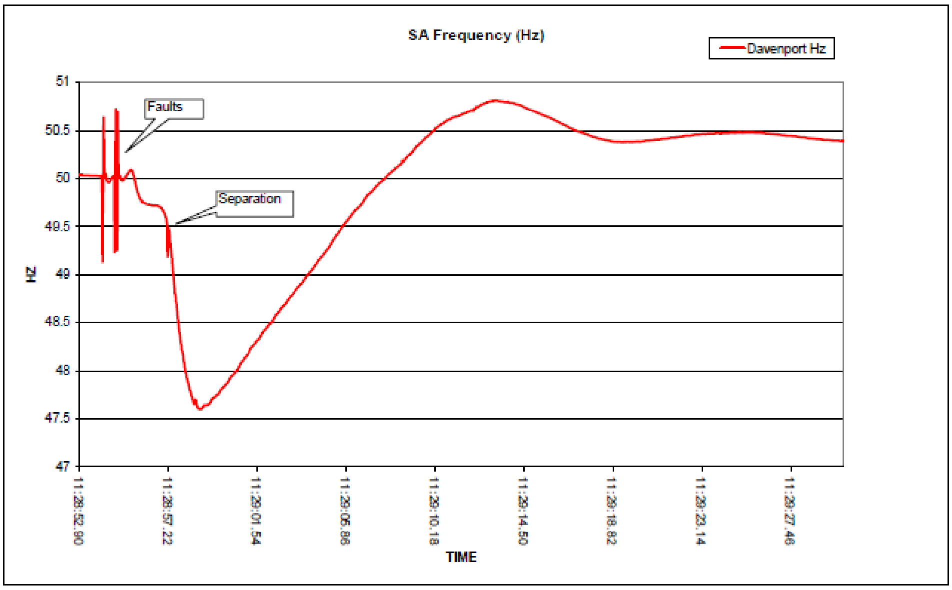

Figure 2: March 2004 SA Frequency[1]

In March 2005 a similar event occurred without the reclosure onto a persistent fault and there were three single phase faults that occurred within a short period of each other. In this event Pelican Point gas turbine tripped due to a fault within the software control of this unit. It was reported that this fault was corrected in April 2005. While Pelican Point may be problematic, it would be cheaper to work with the owner of this power station to improve their digital controls than to apply the import limits that limit the rate of change to 1Hz/s if PPPS is the cause for the concern. Failure of a single unit should not dictate the power flows in the entire region.

Figure 1: South Australian Frequency

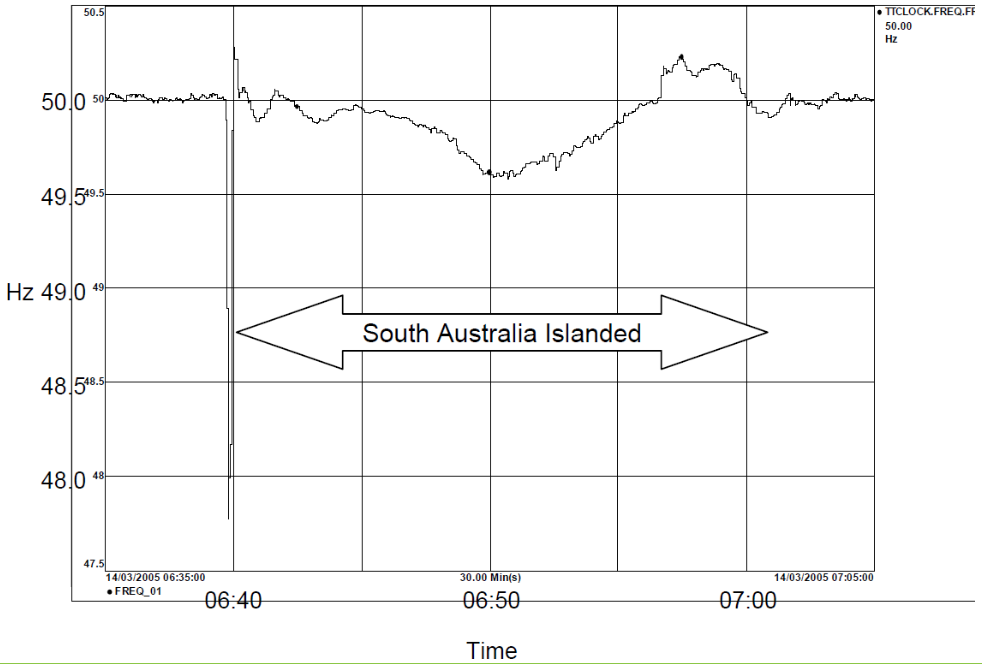

Figure 3: March 2005 SA Frequency[ii]

It is AEMO's role to be expert in understand the existing obligations and its powers under the rules. What is of concern in all of the reports and the incident investigations is the lack of transparent power system analysis within the reports. The failure to identify the root causes of frequency deviations in recent events is concerning, as it is indicative of a cultural shift away from good power system control engineering practises. The result of this has been to alter the power system control operating philosophy at great cost to the participants and customers in South Australia.

The inertial contribution of each synchronous generator is a constant that is normally factored into the transient stability equations such that the limit changes dependent on the inertia available. If the transient stability equations have been correctly calculated then the RoCoF constraint equation appears to be in excess and highly conservative. Transient stability equations must be constructed for all possible limits, such as the limit between regions (Vic to SA, SA to Vic) and for regional stability that is required post separation (ie: with SA post separation). The use of an additional "RoCoF" constraint appears to be over and above the SA transient stability equation that would be required for loss of interconnection.

1.2 Regulation Services

The application of a pre-contingent enablement of regulating services as a guarantee of availability is a direct misuse of a real time control system to manage a future anticipated event. This is not the role of the regulation services. The inertia constraint on the interconnector implies that the synchronous units are on. These are the same units that would provide the frequency response post separation. Likewise the transient stability limit equations should also dynamically adjust the limits in accordance with the inertia available within the region. There appears to be several constraints performing the same role over subscribing the fundamental requirements.

Taking a helicopter view of all the issues going on in "security space" it is clear that market systems have contributed to gross errors in dispatch through the failure of the AWEFS system to reasonably forecast wind farms in the dispatch timeframe. This has added to the perception that wind farms have caused the need for increased regulation services – they have not – the forecasting system has. The 2015 wind integration report goes to great lengths analysing the variability of wind generation as if the frequency of the power changes caused by wind farms is an issue to the power system. The concerns raised over variations which average around 24 MW IN A 5 MINUTE PERIOD is sorely lacking in an appreciation of how loads can and do vary on the power system. The wording that is underlined in the following sentence is illustrative that the author is emphasizing something that is significantly less than the largest contingency in the power system and until the loss of an entire wind farm is the largest contingency this is not a major concern and the emphasis is misplaced:

> 'Due to the intermittent nature of wind, there is potential for sudden variations in generation from wind farms. Analysis of output in 2014–15 shows that for 90% of the time, South Australian total wind generation varies by no more than 24 MW (1.6% of registered capacity) across five-minute periods, and by no more than 38 MW (2.6% of registered capacity) across 10-minute periods.[iii]"

The inability to identify the gross forecast error for an extended period of time means that there is a lack of accountability with respect to the behaviour of these systems. A generator that causes an oscillation into the power system is obliged to have control systems in place to trip off. The market systems that cause oscillations in the dispatch of the power system are free to do so indefinitely. This is a far greater risk to the power system than the behaviour of small intermittent generators.

Around thirty percent of all dispatch periods from July 2012 have had significant forecast errors provided into dispatch by AEMO's AWEFS system. The 5 minute oscillating errors must not be dismissed in the arguments presented in the future of power system security. Any increase in the requirement for regulating services is most likely to have been driven by the coding in these systems. The fact that four years have passed without this error having been identified internally in AEMO is of great concern. If a generator had behaved in this manner it would have been ordered off the system.

1.3 Lack of Transparency

The FPSS discusses the OFGS that apparently had some design work completed in 2013. This scheme has not been discussed nor presented to the affected participants and appears now to be going through due diligence. The report states that is "is likely to lead to trips of non-synchronous generation before synchronous generation". It is evident that AEMO with ElectraNet intend to implement a scheme that will trip off wind farms (non-synchronous) in priority order to manage over frequency events. Under high export and high wind conditions this would be required, although the report also muddies the issue by saying that there may be a problem in low wind conditions. What is not stated is how this is intended to be done nor is there any mention that this would be a contingency lower service. Under S5.1.8 it would be expected that this scheme should have been planned as part of the interconnector upgrade and the cost met by the TNSP in that process.

There is no requirement for a rule change to achieve an appropriate scheme, and generators should be appropriately compensated for the provision of the service as settings below 52 Hz would be an ancillary service. Any co-ordinated Over Frequency settings must be applied at the generator terminals as any other solution is fraught with risk to equipment.

Some statements made in the FPSS are concerned about (protection) "relays may not operate" which would illustrate a lack of practical knowledge of protection schemes and create an illusion that something unknown is occurring on the power system. The FPSS states "As with UFLS, this scheme is only activated during non-credible contingency events, so this challenge would only

emerge on rare occasions". Looking at the event that occurred on the 1 November 2015, it is clear that the planned transmission outage and credible loss of the interconnector caused UFLS to occur <u>for the first time ever in the NEM</u>. The understanding of the author of the report and the control philosophy appear here to diverge.
This illustrates that the operating philosophy has changed, allowing high import during planned outages and therefore using the UFLS for credible contingencies is now modus operandi for South Australia. The cost of the load shedding and regulation services is being borne by customers and others.

Power system security depends on appropriate dynamic mathematical modelling of the physical power system to correctly assess the limits of operation. The analysis reports that underpin the FPSS do not adequately describe the modelling results, and do not engender trust that the results are reasonable. The inability of the reports to describe the limits that avoid system collapse show that either the limits haven't been carefully studied, or the sanitising of the reports has simplified them such that any meaningful results have been removed.

In the 2016 analysis report there is a table that provides information about each known separation event between SA and Victoria:

Table 2 SA separation events

Date and time	Duration	Load shed in SA (MW)	Credible / Non-credible
30/10/1999 0602 hrs	10 minutes	0	Not known
02/12/1999 1311 hrs	26 minutes	1,130	Non-credible
25/05/2003 1702 hrs	56 minutes	0	Credible
08/03/2004 1128 hrs	43 minutes	650	Non-credible
14/03/2005 0639 hrs	22 minutes	580	Non-credible
16/01/2007 1502 hrs	40 minutes	100	Non-credible
19/10/2011 0618 hrs	35 minutes	0	Credible
13/12/2012 0707 hrs	14 minutes	0	Credible
01/11/2015 2151 hrs	35 minutes	160	Credible

The information provided in this report is incorrect: the date was 23 Oct 1999, the duration of the separation was 42 minutes, the event was caused by the loss of more than one transmission line therefore non-credible, 140 MW of load shedding did occur. The time of the event was 1206. [iv].

Readers should observe and question why the 1 November event stands out as the only credible contingency event that has caused under frequency load shed to occur. From a system control point of view it should be closely examined; has there been a higher level of import allowed during a planned outage than was allowed before, or has something else contributed to cause load shed? If the deficit was higher than what was historically allowed under planned outages then it illustrates a significant change in the operating philosophy.

If the import was similar to previous events then it may be that we are seeing directly the changes implemented in the governor control systems as a result of upgraded digital governor control or/and changes made in accordance with the Market Ancillary Services Specification (MASS). The frequency control during the Nov 1 2015 event was inefficient. The performance of the Torrens B units during this separation revealed control issues which illustrate immediate concerns regarding governor controls designed to meet the MASS, (Figure 4 below). AEMO's investigative (Load Shed) report[v] for this incident failed to identify any of these questions, they remain unanswered and it unclear to market participants what action has been taken to correct what should be considered as a significant power system control problem.

What action has been taken to identify other controllers in the power system that could behave in the same manner as the Torrens B units? If action has been taken it has not been made public, little information has been passed to other participants who may have the same governor controls installed.

The only reason we see the direct action of these units on the frequency is because the region is islanded, however there are units in other regions with controllers that may behave in this manner.

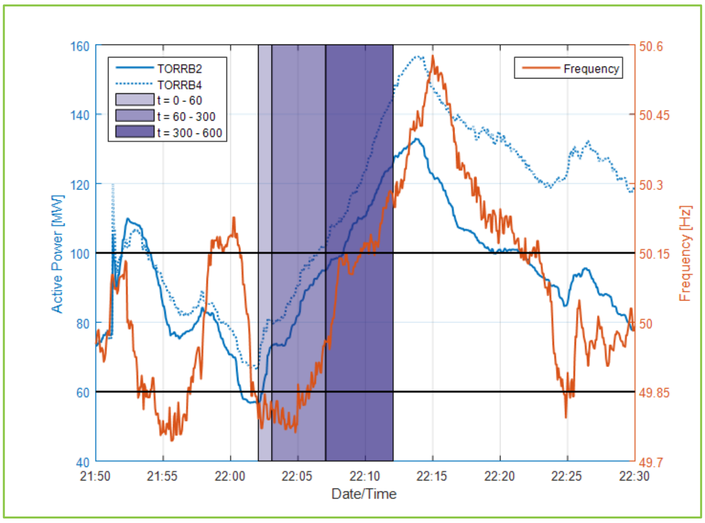

Figure 4 November 1 2015 SA Frequency and Torrens B MW[vi]

1.4 Rate of Change of Frequency

Much of the 2016 report is focussed on advancing the issues identified within the 2014 report. Concerns raised appear illogical such as: “In March 2007, the NER was amended to introduce a requirement for all newly connected generation to be capable of withstanding, at a minimum, a RoCoF of 1 Hz/sec, for 1 second13, without tripping. Generation connected before this, including the majority of thermal generation in SA, may not meet this requirement.”[vii] Given that the generators prior to 2007 have ridden through rates of change of frequency higher than 1Hz/s it would appear that an incorrect assumption is being made concerning the physics of the generating units. In fact, the question that the author should be asking is “What changes have been made to the controls of any generating units that may impede their ability to ride through more than 1Hz/s?” It is not the actual unit that would fail to ride through changes of frequency, but rather second order controls.

Upgrades to the governor control or AVRs of the synchronous units may preclude their ability to ride through high rates of change if for example they have digital converters (AtoD) that are poorly designed. It may be that such controllers need to be replaced (or an appropriate standard required) to ensure that the controllers do not cause the units to trip. The actual generators are capable of riding through high rates of change to the limit of their rotational stability, this should be the expectation and understood from the dynamic modelling.

To make a claim that they “may not” is pure speculation and fails to appreciate the importance of rotor angle stability in dynamic studies. The imposition of the V-S RoCoF constraint is binding and is reducing power system capability now this has a direct economic impact and should be re-examined.

1.5 Good Control System Engineering

It is incumbent on AEMO to provide clear and transparent reports which provide objective evidence to the market regarding the performance of the power system. To date the reports provide limited evidence, simplified statements on the results, and logic that seems to lead to pre-determined conclusions. The updated reports (2016) further entangle reasons for requiring particular outcomes. The conclusions appear to have been drawn in 2014 based on some modelling results. All effort seems aimed at implementing particular solutions most of which are expensive, inefficient and could be construed as biased. Instead of looking to ensure that all grid support services are working efficiently and effectively, the dependence on market mechanisms is overriding good electrical engineering (control) practise.

2. The Future

The FPSS presents a picture that the non-synchronous plants are causing all of the problems – they are not. There are significant control issues being created by changing the control philosophy and the market systems with respect to power system control. The market system is an economic overlay on the power system but more and more it is being used (and treated as) the vehicle for power system control. Many of the existing market systems (such as FCAS) have built in assumptions that disregard the non-linearity's of the actual power system. It is evident from recent events, that there are far greater immediate issues with regard to the control of the power system. These require an appropriate reordering of the priorities within AEMO.

The future of all power stations within the NEM must be focussed on providing efficient power system support services. The market systems that are sending control signals to the power stations have a direct effect on the stability and control of the power system. Some of the market systems (such as the wind forecasting) and unit issues (such the Contingency FCAS control design) present immediate control issues that must be appropriately addressed.

In conclusion, it would appear that the reports and the actions being implemented overemphasise the issues while more immediate problems are obvious and should be addressed.

2.1 References

[i] SA Separation 8 March 2004 232-0019
[ii] 14 March 2005 SA incident 232-0024
[iii] 2015_SAWSR.pdf p5
[iv] Final report 23oct99 incident
[v] Load shedding in South Australia on Sunday 1 November 2015
[vi] WIF March 2016 KS - Final
[vii] Joint AEMO ElectraNet Report_19 February 2016 p 14