PacificHydro

For the attention of Dominic Adams

Pacific Hydro Submission on the Generator Technical Performance Standards Rule Change

Pacific Hydro is pleased to have the opportunity to provide feedback on the draft determination and proposed rule changes. Pacific Hydro's main concern is that the new rules are extremely onerous in places and appear limited in any engineering justification. The criteria introduced in S5.2.5.5 are complex and difficult to interpret as to how to undertake a meaningful set of studies. The rule creates an extremely onerous obligation on connecting parties that cannot be fully studied.

These rules have also changed the use of terminology; i.e., "generating system" replaces "generating unit" altering where the performance is to be measured. These changes are likely to give rise to confusion and require clarification in order to provide clear and unambiguous direction to engineers when studying the connections.

A number of rule changes that appear to be unsupported by sound engineering practise are detailed below:

First and foremost the changes to the fault ride through conditions as drafted in the proposed rules represent a significant deviation from past practise. There is apparent lack of understanding illustrated in the Commission's determination report which creates a significant safety risk underpinning these rules. The Commission has interpreted Pacific Hydro's first submission to state the following:

"AGL and Pacific Hydro considered that most synchronous machines can maintain continuous uninterrupted operation for six or seven faults, but not all generating systems could maintain continuous uninterrupted operation for 15 faults.[699] "

This is a significant misinterpretation in the part of Pacific Hydro's submission which stated:

"The shaft of a gas turbine is <u>likely to shatter if exposed</u> to more than 6 faults in close succession."

Pacific Hydro has highlighted the relevant safety risks and rejects the AEMC's interpretation of our first submission. The shattering of a shaft does not represent "continuous uninterrupted operation", but, rather, significant fatigue leading to catastrophic failure of the generating unit. The misinterpretation suggests that there may be significant gaps in understanding the market legal framework which appears to ignore the physical forces that are present in power systems.

The dismissal of the physical reality is a significant concern and the implementation of these rules appears to place maximum risk of any grid failure onto generators without adequate technical understanding of the forces that must be controlled. Such forces cannot be managed with contracts, policy or rules. These forces are only controlled through thorough electrical control and protection engineering methods and practise; the discipline and practise of which is now significantly diminished and under threat in the NEM.

The reality of a catastrophic failure of any generating unit represents a significant risk to lives of power industry workers, and while the risk is low, the consequence of such an event is extreme. Such events must be safe-guarded against, and must be mitigated through thorough understanding of the complex interactions of machines on the power system. This is a highly technical aspect of control engineering and Pacific Hydro cautions against rules or rule changes which result in increasing obligations to “ride through” disturbances.

There are several catastrophic events that could be cited but one example is Sayano Shushenskaya . On 17 August 2009, 100 workers died in the power station as a result of a unit failure following a load rejection.

Pacific Hydro recommends that an overarching objective be inserted into Chapter 5 under clause 5.1A.2 Principles:

(f) “the technical terms and conditions must allow for the *Registered Participant* to reasonably protect *generating units* from damage when the *power system* is operated outside of the principles of good electricity industry practise or the procedures set under Chapter 4.”

These rule changes drive a philosophy of maximum capability into generators while expecting that control through centralised market dispatch will be adequate to manage the performance of the power system. This is an unproven experiment which has so far managed to deteriorate the reliability and actual control of the power system significantly.

There are significant problems introduced by these rules changes that are extremely complex. The rules changes must be accompanied by in-depth engineering guidance on how they are to be applied in practise. An example is the highly problematic drafting concerning reactive current injection and maximum continuous current in the general requirements of S5.2.5.5.

According to the AEMO representative at the AEMC’s industry forum, the multiple fault ride through criteria is intended to capture issues associated with weak system strength and critical clearing times on synchronous machines. However, the proposed rules do not define the limits of low system strength nor do they refer to the stability risk present when synchronous machines are responding to a fault (or multiple faults) within a network.

Pacific Hydro believes that it would be extremely improbable to be able to study and agree to meet the criteria for all combinations of events, the loss of network elements and the locational nature of events which all contribute to circumstances that will be beyond the operational capability of equipment. This rule change is extremely onerous and appears to have been designed to make all generators culpable for all future failures in the power system.

Both critical fault clearing times and low system strength are important limits to what can be physically tolerated by generating units on the power system. Of the multiple faults listed, most of them will remove a network element from service; the only fault that is likely to see the network remain in service is a single phase to ground with successful auto reclosure. All others will remove network elements - or worse - a circuit breaker fail will strip a bus, removing a node from the power system.

As each network element is removed from service, the system impedance will increase and the system strength will be reduced. If the system strength drops below the level at which an inverter control remains stable, the inverter must trip off the system as it cannot operate in an unstable manner on the power system.

Synchronous machines, depending on their location within the network and the location of each fault, will either accelerate or decelerate. A machine is either feeding the fault or picking up load that was otherwise supplied by the units that feed the fault. The system protection is designed on the critical fault clearing time (CFCT) for a single worst case contingency. In the event of multiple contingencies, the angular separation between machines will change and timing associated with the critical clearing time for the second fault will differ. A unit must protect itself whenever an event or a sequence of events is severe enough to cause the unit to over speed, become marginally stable or unstable in response to the power system.

The justification report for the multiple fault ride through provided by AEMO to the AEMC has not had any independent engineering peer review. The modelling performed has not been described at all, is not transparent, and nor are the results reliable. It should not be relied upon to justify the dramatic change to the obligations on participants. Any equipment manufacturers which claim that their equipment can meet this requirement are likely to have been using disturbance bench testing to come to that conclusion. AEMO is rejecting disturbance bench testing as a method of proof. Pacific Hydro understands that the CEC has been informed that the problem is more “mechanical”. Therefore no OEM has undertaken a full set of modelling in the manner expected by AEMO’s recent Power System Modelling Guidelines and cannot demonstrate full compliance with this rule. Manufacturers are unlikely to have EMT models that would satisfy all of the new guidelines.

To undertake any form of due diligence on the multiple fault ride through would have to take into account the number of fault types, the number of disturbances, and the locations around the network where the faults could occur. The network model has at least 2300 buses. Even assuming local area faults and reducing the faults considered to 100 nodes, the number of studies required would be: 2.533×10^{157} which does not include selecting the various combinations of fault types within the 15 referred to in the rule, which would increase the number.

To date, AEMO and the Commission have not provided guidance on how a participant, using existing engineering practise, is to confirm compliance with this rule or validate and test plant once installed. This will leave connecting generators to be permanently non-compliant or not validated.

Furthermore, the inclusion of protection into the models, will mean that the capability of the system is no longer being studied, only the protection outcomes. This is a dramatic philosophical change to power system studies which appears to be driven by a perceived gap in expert knowledge and a desire to have a mathematical model that stops when protection trips. Dynamic models are normally used to inform protection engineers about where to set the protection.

The complex modelling that AEMO expects, combined with the convolutions within the rule is exposing the market participants to unacceptable levels of risk.

Pacific Hydro believes that the intention and reasons for the changes to S5.2.5.5 are unworkable as they are currently drafted.

If it is to proceed, Pacific Hydro recommends that limits are placed into S5.2.5.5 that put boundaries around the expectation that all units can remain connected through every event; this is not a matter of fact and is physically unrealistic.

Making the wording around “any combination” is inappropriate as almost all of these events will remove networks elements from service. Making the requirement into a rolling 5 minute window ignores the fact that fault current heats electrical equipment, and for equipment to continue to operate, it needs to cool down. For example the two second overload capability of Statcoms requires a recovery period of at least seven minutes.

S5.2.5.5

Into S5.2.5.5 (b) (1A) and (c) (1A) insert:

"provided that none of the events:

(vii) island the *generating system* or cause a material reduction in *power transfer capability* of the *generating system* by removing *network elements* from service*;*

(viii) result in a *fault type* that fails to clear in accordance with S5.1.9 leading to an unstable *generating unit* or *power system;*

(ix) result in a *fault type* that causes a synchronous *generating unit* or synchronous condenser to trip for loss of synchronism;

(x) cause a material reduction in *system strength* by removing *network elements* or synchronous *generating units* from service affecting the stability of the *generating system*;"

General requirements of S5.2.5.5 and reactive current control

The complexity of the additional requirements around reactive current injection and the response of a generating system appear to be onerous and unnecessary. The drafting makes the requirement difficult to understand. Fault studies and the response of plant through a fault and the recovery of the plant is non identical and will depend on the fault type, its duration and severity. The changes to the criteria, the number of faults and the expectation that reactive current will be available and identical is unrealistic.

The following draft requirement does not make sense:

(6) notwithstanding the amount of reactive current injected or absorbed during *voltage* disturbances, the maximum continuous current of the *generating system* including all operating *generating units* (in the absence of a disturbance) must be available at all times, except that *AEMO* and the *Network Service Provider* may agree limits on active current injection where required to maintain *power system security* and the quality of supply to other *Network Users*.

We recommend this is altered to allow for the fact that the maximum "continuous" current cannot be "available at all times". The maximum continuous active current will be in accordance with the MW production level at which the remaining units are operating. Pacific Hydro would like to understand the objective of this clause as the maximum available current at any one time will only ever be the sum of current available from the operating units. Which, if constrained will be in accordance with the dispatch target. Pacific Hydro recommends deleting this clause until it can be clarified. For instance, if this is specifying that inverters must provide reactive current when the generating system is not generating, then it is not a technology neutral clause. This is asking generators to provide voltage control when they are not generating.

S5.2.5.7 Partial Load Rejection

This rule was implemented for large synchronous generation as it requires them to be capable of riding through a significant reduction of electrical load on their terminals; this is referred to as a "trip to house load" operation, or to island with a smaller load, provided it can be stabilised. Large synchronous units will over speed and trip if they do not control themselves during load rejection and it is about the load on their terminals – this is not a "system" action. Thermal plant use by-pass valves to blow steam off and reduce input energy to stabilise. Hydro units use the insertion of braking resistors or load banks to control the reduction of load on their terminals. This is necessary for the speed control of synchronous units which are coupled to the system frequency. Asynchronous units do not have the same technical issues and as they cannot control frequency in isolation, they are required to trip when islanded with local load. To this extent it makes no sense to reapply this rule to asynchronous plant. It also makes no sense to remove the negotiated standard as not all synchronous units will have the full capability expected under this clause. Pacific Hydro recommends leaving the rule as it currently stands or identify the actual problem is that the rule is intended to fix.

Frequency Response and Control

In **S5.2.5.3**, please delete the addition for the automatic standard that adds in "-3 Hz to 3 Hz per second for more than one second". By definition this is obsolete as 3 Hz in one second would mean the system is at 47 Hz in one second. This rate of change for more than one second would mean all units are off. It makes more sense to require the existing -4 Hz to 4 Hz per second for more than 0.25 seconds. It does say "for more than" which is a higher rate of change than 3 Hz per second. To add in the 3 Hz/s is a meaningless addition. If the rate of change of frequency is 4 Hz/s then the frequency will fall by 1 Hz in 0.25 seconds, but if it is 3 Hz/s then the frequency will fall 0.75 Hz in 0.25 seconds. Pacific Hydro would like to understand the rationale for the addition into the automatic standard that is a lesser rate of change and seeks clarification on which one is the expected standard. Anything changing at this rate for greater than a second will cause a system collapse as it is incumbent that control responses (such as governor controls) respond prior to reaching 47 Hz to arrest the fall of frequency.

S5.2.5.11

The control of the power system is being grossly affected by both the market dispatch and the existing arrangements for frequency control. Without appropriately considering the outcomes, the rules changes propose to widen the control capability so as to allow generators to have controls that do not respond until after the under frequency load shedding (UFLS) commences. (e.g.: deadbands capable of being set between 0 to +/- 1 Hz.) UFLS commences as soon as the frequency falls below 49 Hz. A deadband capability as wide as +/- 1 Hz is meaningless in terms of power system control, so such an idea in the performance standards is without any practical application. Widening capability through the words in the rules to a deadband of approximately 300 mHz (+/- 0.15 Hz) has already been proven to have created a frequency control problem on the power system. A further increase of the deadband "capability" to a 2 Hz capability is likely to produce greater frequency control problems on the power system.

Pacific Hydro recommends that the deadband capability be altered to be set within the range of 0 to +/- 0.15 Hz. This is requiring a deadband no larger than 300 mHz. It is evident that the current 300 mHz has caused a detrimental deterioration in the frequency control on the eastern seaboard.

The rules must recognise that not all technologies can operate with a 0 Hz deadband, so in reality the deadband should be specified as being less than -0.15 to +0.15 Hz.

The AEMC has explained to Pacific Hydro with conviction, that the market framework will resolve the technical control problem. This seems to be based in the belief that the market fully understands the problem, its complexity, the consequences for not getting it right, and how to fix it. This is letting the market "framework" decide how the power system should be controlled.

Pacific Hydro recommends that the AEMC recognise that the opening statement of both the Automatic (and Minimum) access standard be understood to mean what is says:

The *automatic access standard* is:

(1) a *generating system's power transfer* to the *power system* **must not**:

(i) increase in response to a rise in the *frequency* of the *power system* as measured at the *connection point*; or

(ii) decrease in response to a fall in the *frequency* of the *power system* as measured at the *connection point*; and

This clearly means that the control action must not respond in contradiction to this statement. Yet this is precisely what is occurring on all units that are obeying the FCAS market. The market has created a mechanism that contradicts a technical requirement of the power system.

At the outset of the NEM it was acknowledged that the market was never intended to replace power system control methods. Power system control and the associated primary control systems with appropriately co-ordinated settings are necessary to ensure that all machines are operating efficiently and stably together. The market was expected to be an externality to the actual power system control while it managed the economic dispatch order of units.

The evolution over the last two decades of competition into machine control systems in the manner created by market mechanisms is contradictory to good electricity industry control practise. The enablement and disablement of primary controls in accordance with an economic dispatch has intrinsically weakened the power system and undermined reliability. This increases the likelihood of system failure.

Pacific Hydro recommends changing general requirement (i) (4) which says

"a *generating system* is required to operate in *frequency response mode* at all times in accordance with (b)(1) and (c)(1); only when it is enabled for the provision of a relevant *market ancillary service"*; and

All synchronous machines must control their rotational speed to their nominal rotational speed design, this is fundamental. Without the controls managing dynamically their rotational speed, they are hunting against each other. It is highly inefficient and detrimental to their reliability and the power system loses its control reference.

The market ancillary services are NOT frequency control; they are time error correction and spinning reserve services. The delivery of active power to the system must be controlled at 50 Hz. Otherwise there are too many complex flow on effects which were described to the AEMC through the IEAust's submission to the Ancillary Service market framework review.

The market philosophy appears entrenched in the AEMC's thinking; the technical standards must not forego the technical requirements of control on the power system. There are parallel market reviews that will interact with the technical rule changes and all of them affect the power system. However, the technical standards appear to be taking a back seat setting up stringent almost impossible obligations in some areas while abdicating all responsible control decisions in others to the market. It would appear that no matter what engineering practise would do, there is favouritism towards market mechanisms in all situations. This is unproven, unreliable and inefficient and will result in damage to large parts of the infrastructure, the results of which are only now starting to become evident.

The lack of primary frequency control will result in an expensive disorderly transition without appropriate planning.

S5.2.5.13 Voltage and reactive power control

It is illogical to remove the obligation on synchronous units to have limiting devices and a power system stabiliser. This appears to be a drafting error. There must be a clear and unambiguous obligation for these controls; (b) (3) (iii), (v), (ix) and (x) need to be reinstated. From Pacific Hydro's perspective, the rules appear to be drafted in a manner which imposes more obligations for "support" of the network" on asynchronous units while removing obligations on synchronous machines. The drafting could be construed as biased or misinformed.

With respect to providing controls for AEMO or the NSP to "remotely" switch the control of a generating system from voltage to power factor or reactive control, Pacific Hydro would like to understand how the Commission (or AEMO) will guarantee that such a change will not inadvertently cause a significant vector shift when an operator takes control, and what limits are being placed on the control functionality. Furthermore, hat guarantee does an owner have that AEMO will control the voltages correctly and not cause a generator to become non-compliant noting that performance standards are agreed based on control set points.

S5.2.5.14 Active power control

By making all generation subject to AGC there will be an unnecessary increase in communications on the power system. As the AGC is a remote control system –a requirement for local control systems is recommended rather than putting all generating units under AEMO remote control. AGC is a time delayed controller and cannot replace local control systems.

This set of rules is trying to force semi-scheduled plant to be controlled in the same manner as scheduled plant. It would appear the remote control from AEMO is being considered as top priority whist the need to ensure that appropriate primary controls on all plant are not being addressed.

The changes that require all small plant to respond to AGC is illogical, this must be negotiable. This does not improve control on the power system, it will increase SCADA congestion, increase the oscillatory responses that are present in the power system. Lastly, it is adding cost by requiring small generators to be connected to the AGC. There appears to no appropriate power system control philosophy under pinning this change.