AE04-AECO-RPT001 Review of NEM Frequency Operating Standard GHD consultancy report

Rev 2

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1 Summary

Provecta Process Automation is a specialist electrical, industrial IT/OT and controls engineering company working in critical infrastructure, particularly in conventional and renewable generation, water and wastewater treatment in Australia and internationally. Mr Parker has been a specialist power plant controls engineer for 43 years and is recognised internationally, having provided services in NZ, Asia, UK and the USA, including a period of over 4 years managing the company's US branch.

Provecta was requested to consider particular aspects of the GHD report, particularly qualitative comments on:

- Impacts on thermal plants as a result of the PFCB that do not appear to have been fully captured by GHD;
- Qualitative postulations on the likely causes of the 'wobble' (system frequency cycling which is not always centred around 50Hz) and whether they are likely to be relieved by a slightly wider PFCB.

The following summarises observations made in this report.

1. Significance of PFR and difference to R-FCAS

It is recognised that PFR is essential to system security, and cannot be replaced by remote dispatch demands which are far too slow. PFR is fast, proportional, local and performs the function of arresting frequency deviations. In a generation loss event, frequency usually falls, initially at the rate determined physically by the quantity of synchronous rotating generation inertia and frequency-sensitive rotating loads, reaches a nadir as PFR responds and as RoCoF-related generation has returned to zero, and then 'bounces' back to a settled point determined by the speed of PFR response and total system droop.

PFR on conventional thermal generation plant responds with time constants (time to reach 63%) ranging from 10s to 30s depending on plant capability and control system design and tuning. Special functions are often applied to the boiler and governor controls to provide these fast steps in generation of up to 10% MCR. On the other hand, R-FCAS is rate-limited to the demand rate set locally and is typically 1-2%/minute. Thus, whereas PFR may generate a 10% MCR step in 30s, R-FCAS would achieve between 0.5 and 1% MW change in the same period and cannot respond quickly to frequency deviations.

Clearly, the cost upon boiler/turbine components is far greater with PFR than the ACE-based adjustments made by R-FCAS.

Nonetheless, even regular sawtooth-style R-FCAS demand changes introduce their own challenges to plant operation, albeit over a longer period and therefore affect slower processes in the boiler, particularly boiler steam pressure and temperature oscillations which can impact plant life. R-FCAS demand profiles should be optimised to minimise these effects on generating units.

2. System frequency cycling

The interconnected system is experiencing slow frequency cycling with a period of 18-24 secs, as reported by AEMO [1]. The peak-to-peak variation is around 20-40mHz and is not always centred around 50Hz, and therefore is not purely a function of limit-cycling around the deadband region, which can often occur in the control of integrating processes such as frequency when small deadbands are applied. This oscillation at times exhibits a 'beat' of about 5 minute period as shown in the AEMO white paper, which indicates the cycles may be initiated by resonances of slightly different base periods, which is surmised as coming from different MW response delays to R-FCAS commands.

One aspect of remote dispatch control in the past that has caused local MW instability was the operation of the AGC dispatch controller using generated MW as its process feedback, effectively creating a remote MW controller driving the setpoint to a local MW controller, which breaches fundamental control theory for cascade control structures. When local generation has a MW delay due, say, to governor hysteresis, the AGC demand would overshoot and had caused slow, cyclic MW variations as AGC 'chased' generation to the target. This was overcome at several stations by AGC switching to setpoint feedback. It is recommended that this arrangement, if not already done, be deployed at all stations in the NEM.

3. Impacts of cycling

While it is recognised that the narrow-band MPFR action generally holds the frequency to well within the NOFB, it is doing so in reaction to oscillations that are usually wider than the band and therefore generators are responding cyclically to what appear to be deviations caused by delays in either frequency response, R-FCAS MW following or regulation commands themselves, rather than random variations in generation/load imbalance.

As described in the report, the cyclic nature of the frequency deviations is causing excessive movement on many controlling devices, particularly in boiler components, as the boiler demand is 'kicked' by around twice as strongly as any change in MW demand during PFR activity, as required to help overcome the inherent boiler delay. Several boiler demand signals apply the rate of change of unit demand (including fast PFR bias) to form time-leading kicker elements, therefore cycling activity is amplified in the boiler controls and generates faster, more frequent actuator movements.

4. Frequency histogram 'skew' and R-FCAS operation

The source of this perceived skew away from being centred around 50Hz has not been investigated. However it is noted that the algorithm uses a deadband rate-limiter as described in the GHD report. When the rate limiter is active, a false deviation is being fed to the controller which can cause a long-term integration error. Instead, a low-gain region without rate limiting should be applied to the integrator. Any proportional component in the algorithm can have a pure deadband applied.

5. Notes on the current deadband setting

It is suggested that widening the deadband to +/- 30MHz would eliminate much of the PFR reaction to this cycle while still providing tighter control over frequency than before MPFR was introduced. Figure 2 shows the improvement in frequency spread since MPFR was introduced, but it also shows that in 2009 (and also the case earlier) that voluntary PFR, with deadbands on units ranging from 30mHz to 50mHz, was also narrow and close to the current profile.

One example quoted by AEMO of a system using narrow band is ERCOT (Texas) [2], set at +/- 17mHz. But the table from the ERCOT operating guide [2] provides two sets of bands; refer extract in Figure 1. Note that mechanical governor turbines have a wider band allowed. This appears to be in recognition that there is a natural deadband in mechanical governors due to hysteresis (backlash) and the requirement to consistently provide PFR needs to begin outside that natural deadband. This is considered again with an example in Section 3. If applied to the NEM, in NSW this would affect eight large units. The wider band would also apply to some stations in other states.

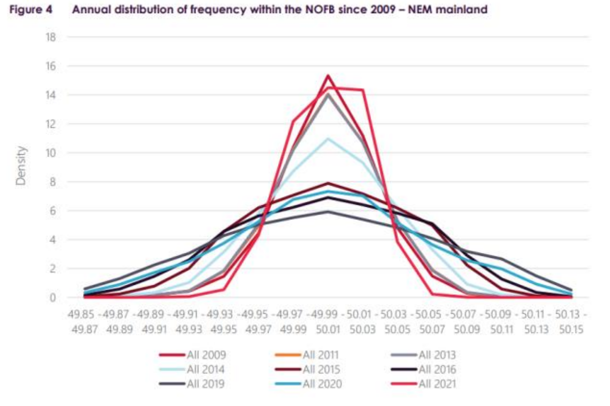
<u>6. Suggested alternative to single-deadband PFR</u>

It is suggested that consideration should be given for a three-region PFR droop profile: 0-15mHz dead band; 15-30mHz 10% droop; over 30mHz 4% droop. These adjustments can be readily made in most DCS-based MW controllers and would reduce the impact on boiler-turbine processes while still providing support to hold frequency well within the NOFB.

Table 1: Maximum Governor Dead-Band Settings

Resource Type	Max. Deadband
Steam Turbines with *Mechanical Governors*	+/- 0.034 Hz
Hydro Turbines with Mechanical Governors	+/- 0.034 Hz
All Other Generating Units/Generating Facilities/ESRs	+/- 0.017 Hz

Figure 1 ERCOT PFR deadband settings [2]



A1.1.1 Frequency distribution

Figure 4 shows the annual distribution of NEM mainland frequency within the NOFB since 2009, highlighting significant degradation of frequency control from 2013 onwards, and the improvement post-MPFR in 2021.

Figure 4 Annual distribution of frequency within the NOFB since 2009 – NEM mainland

Figure 5 illustrates the gradual improvement in frequency performance within the NOFB since 2019, over the course of the MPFR rollout.

Figure 2 Comparative annual frequency distributions in the NEM [1]

2 Comparing responses of R-FCAS and PFR and relative work burdens

The GHD report makes comment that increasing the PFR deadband requires a compensating effort by R-FCAS to manage frequency. This was done to enable cost comparisons to be made by using the AEMO values placed on the services. However there are several matters of concern with this approach:

a) R-FCAS performs a different function to PFR.

The following uses a low frequency event scenario by way of example.

PFR is local, immediate and proportional. As it only responds to in direct proportion to a frequency deviation, the only way it can provide a change in MW to help re-balance the system is for there to be a residual, settled change in frequency that is in proportion to the original imbalance that has been restored.

R-FCAS, as secondary control acts to eliminate the residual frequency error through AGC by driving system generation up, causing frequency to rise, progressively reducing the frequency-biased generation and restoring rotating kinetic energy. The R-FCAS is by design a Proportional plus integral controller. The integral action continues to bias up the AGC demand until frequency deviation is eliminated. The proportional component is not required from deviation correction, but as frequency response is an integrating process, integral-only control of an integrating process in inherently unstable and proportional action is required to maintain phase margin for system stability.

During deviations around 50Hz, the R-FCAS proportional action can slightly assist with PFR if it is fast enough. Observations of some event trends have shown the 24-s period instability occurring, but also shows an R-FCAS signal driving MW demand with a phase delay of up to 90 Deg. The cause of the delay is unknown but may be related to communication, filtering and AGC demand processing delays (or possibly only a charting error).

During the restoration period after the frequency has settled, not only will PFR action be biasing MW down as the low frequency deviation reduces, but the proportional action of R-FCAS will be doing the same. A higher proportional gain in the R-FCAS controller could help keep frequency within PFCB, provided its output delay did not cause further instability, but in its role to *restore* frequency after an event, higher proportional gain will actually slow the recovery trajectory.

b) Questions exist on R-FCAS design and performance

The control design for R-FCAS provided in the GHD report, if representative of the actual implementation, appears simplistic for the complex system being controlled. It was surprising, for example that AEMO report on a need for manual bias to the controller to restore frequency error due to having a deadband in the controller. Since this is the overall ‘trim’ controller of an integrating process, basic control design mandates that the integrator must not have any deadband or there will be drift to the deadband edge, either remaining there or limit-cycling between limits. This can be overcome by either applying a deadband the proportional component only or including a low-gain region instead of a pure deadband.

There has been much activity in exploring improvements to regulation control of networks [6] lists around 300 relevant research papers with over 100 in the last 10 years, so it could be anticipated that R-FCAS would be further optimised over time.

c) R-FCAS work is not equivalent to PFR work

If R-FCAS could be adjusted to reduce the frequency histogram ‘skew’ and attenuate the slow frequency cycles in an optimised manner, PFR could be widened with minimal change to system risk, due to a naturally narrower bell curve. R-FCAS moves MW demand at the unit ramp rate, which does not ‘overfire’ the boiler as hard as PFR, and should be optimised to minimise load demand reversals by incorporating model-based control algorithms that place a cost on activity and direction reversals.

3 PFR response dynamic variations – possibly contributing to the system cycling (control and mechanical factors)

Frequency response dynamics are not the same for all generators. Factors including MW controller cycle time (ranging from 0.1s to 1s in the NEM Interconnection), tuning and control structure (including pressure cross-influences), DCS protective overrides and governor rate limiting.

A simulation of frequency dynamics due to partial generation loss, with only synchronous thermal generation responding was constructed by the author in Simulink using an IEEEG1 turbine model (set for a 60Hz interconnection), and detailed unit co-ordinated controls. The simulation gave the results shown in Figure 3 by varying MW controller parameters and structure.

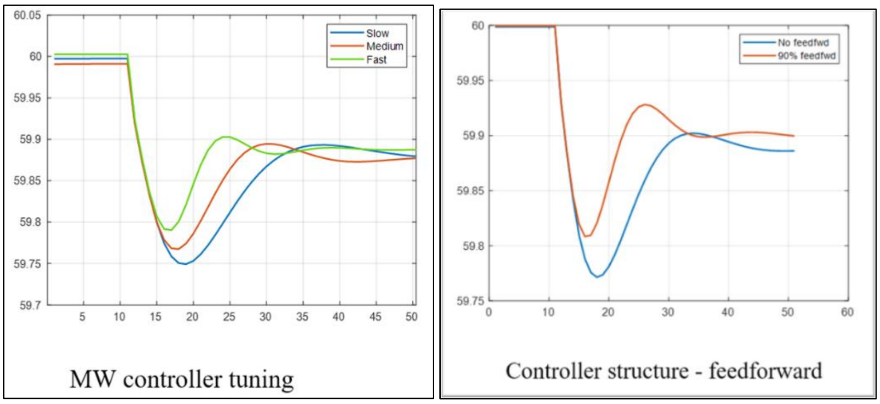


Figure 3 PFR MW controller design and tuning differences affecting the nadir

This is a reflection of the range of effects different PFR generation responses can have on frequency dynamics. While each generator is required to provide response models and confirm response performance, it is uncertain how the actual performance of each generator, or mix of generators at any point in time will affect overall frequency response and system deviations. Some combinations may contribute more to system cycling than others.

Another variation in PFR response in turbines with mechanical governors can arise from backlash or hysteresis as components wear. Of course some backlash is inherent to avoid stiction and allow for machining tolerances, but it is not uncommon to encounter 20mHz total hysteresis band, as demonstrated in Figure 4. This plot was taken from a period where a turbine governor that participates in the NEM was on manual for a set of tests, and during periods at two different positions the system frequency changed substantially. Since the linear HPCV position is derived from steam pressure ratios, there is some noise in the vertical axis but operation in the 49.95-49.98 region shows at least 20mHz hysteresis. This should not be considered abnormal as anecdotally, turbine manufacturers had expected 20-30mHz hysteresis in their systems.

This can affect PFR performance, depending on where the governor is in relation to the backlash at the time of action, and can also add a small delay (up to 30 secs) to R-FCAS response.

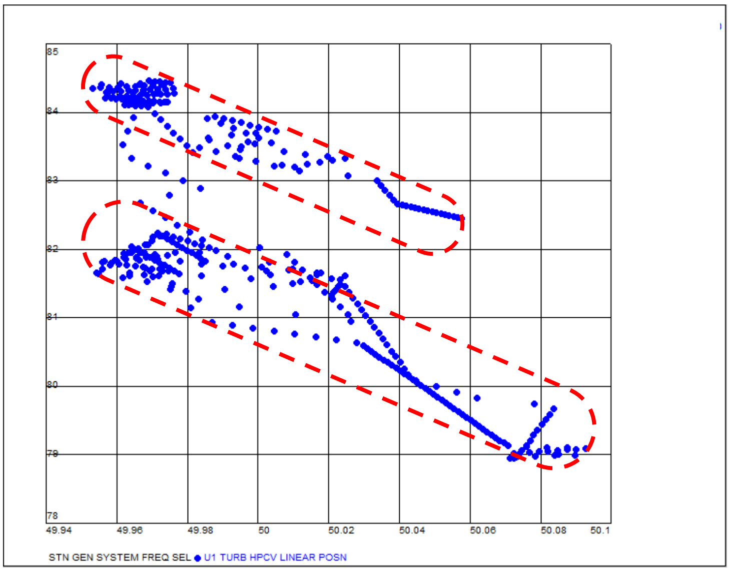


Figure 4 Mechanical governor hysteresis, at least 20mHz total.
(Governor on Manual at two base positions, during high frequency-droop activity)

4 Examples of effects on unit processes from frequent PFR activity

The following sections give some examples of boiler and turbine processes affected by PFR activity. Figure 5 shows some of the major processes affected. The focus here is on the effects of responding to the narrow-band frequency deviations, and particularly in response to regular PFR activity stemming from the frequency oscillation of 18-24s period that is occurring.

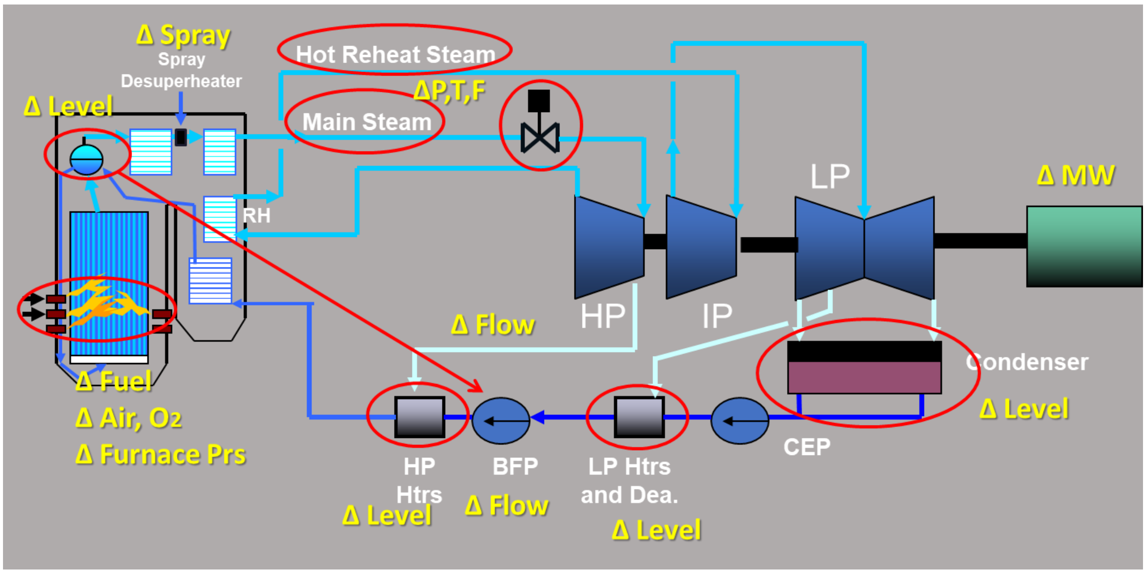


Figure 5 A frequency excursion disturbs around 30 control loops and 50 modulating devices

Some examples describe process effects on boiler operation and efficiency, some on the impact of operator adjustments to setpoints to raise unit security and others on the wear and tear of field devices.

To support the claim that PFR is more damaging to plant than R-FCAS for similar MW movement, we consider loops that are more affected by PFR than by R-FCAS. This is done by identifying processes that have closed-loop time constants less than or equal to 25 secs and are therefore affected by the frequency cycling and constant fast activity occurring at the PCFB boundaries.

Table 1 Boiler/Turbine processes with closed-loop time constants less than or equal to 25 secs

Process	**Approx. closed loop response time constant (with typical tuning) (Note 1)**	**Control elements (typical)**
Air Flow	10s	FD Fan blades x2
Furnace Pressure	8-15s	ID Fan blades/vanes x2
PA Hot Bus Pressure	20s	PA Fan vanes x2
Mill air flow	15-25s	Mill air reg. dampers (multi-leaved), up to x6 at full load
Mill fuel flow (vertical spindle mills)	5s	Mill feeders (VFDs) up to x6 at full load
Superheater Spray desuperheater temperature	25s	Spray water valves (between 4 and 14 per boiler)
Unit MW (DCS control including frequency bias to Turbine master)	8-20s (depending on design and tuning) (Note 2)	Turbine Governor and CVs
Drum level (feedwater)	10s (feedwater response to steam flow change)	Boiler Feed pump

Note 1. The time for the process to reach 63% on a setpoint step change.
Note 2. Open loop response is 3sec HP component (30%) plus 12sec RH/IP/LP component (70%) with slew-rate limiting to Governor, giving a complex MW control response with fast and slow components.

4.1 Steam temperature deviations

Increased PFR activity coinciding with ramp-related deviations can generate steam temperature exceedances. Steam temperature alarming will generally lead to temperature setpoint reduction. It is not expected this reduction would be great, but for a 660MW Rankin-cycle Reheat unit as an example, a 2℃ reduction in main steam temperature would result in a 0.055% efficiency reduction, increasing CO_2 emissions by over 1,000 tons per unit per year and up to $60-90,000/unit/year assuming 60% capacity factor [3].

4.2 Cycling causing material stresses

So long as cyclic frequency movement is being experienced on the system, PFR commands feeding directly to the Boiler and Turbine Masters, and the related fast process changes in steam flow and pressure, can lead to cyclic stresses in both boiler and turbine components. The impact of such factors is outside this study’s scope, but effects of cycling, including thermal fatigue causing tube and header cracking and magnetite exfoliation are well researched and recorded phenomena [4]. The fast rates of change from the periodic PFR response will introduce high thermal change rates over relatively small temperature changes. Modern analysis tools are available to assess life consumption and stress-corrosion risk as a result. An extensive dynamic model study of the stress impact of PFR on boiler headers has been published in [5].

4.3 Excessive boiler control element activity

Boiler/turbine units operate in a Unit Co-ordinated mode, which operates on processes that are non-linear, interactive and time-varying. In particular, by providing fast MW control with the turbine valves and controlling the boiler heat input to maintain steam pressure, the pressure responds as an *integrating* process, that is, unless heat input required for a particular generated power exactly matches the MW that the turbine controls are set to deliver, steam pressure will continue to rise or fall until a steam flow/MW balance is restored. The effect on steam pressure is therefore similar to system frequency requiring a constant generation/system load balance. Integrating processes are inherently unstable require control designs with stabilising components.

The slow response of thermal steam generators, including drum and supercritical once-through, means that any load demand change, whether for ramping or PFR, requires additional, leading fuel movement to 'get ahead' of the delays. these are in the form of various 'kickers' which are derived on the rates of change of load demand and steam pressure setpoint. Hence, the faster movement of PFR-based load change can result in greatly increased boiler response compared to ramping with R-FCAS.

For example, a 2% change up in MW demand from PFR (0.055Hz) would demand around a 4% change in fuel flow, air flow and induced draft extraction, and fast spray valve movements. Even small load changes generate sufficient drum shrink/swell to cause additional boiler feed pump movement above the normal load-demand and level control activity.

Figure 6 shows an example of this effect with the results from a frequency injection step response test at low load on a large drum-boiler unit. A frequency deviation calculated to generate 5% frequency bias action was injected in the DCS. Note the requirement to over-fire the boiler by 100% to recover steam pressure to the new load point, and also the need to drive the turbine governor well beyond what would have been a 5% "droop" movement of the CV in the event of a real frequency disturbance.

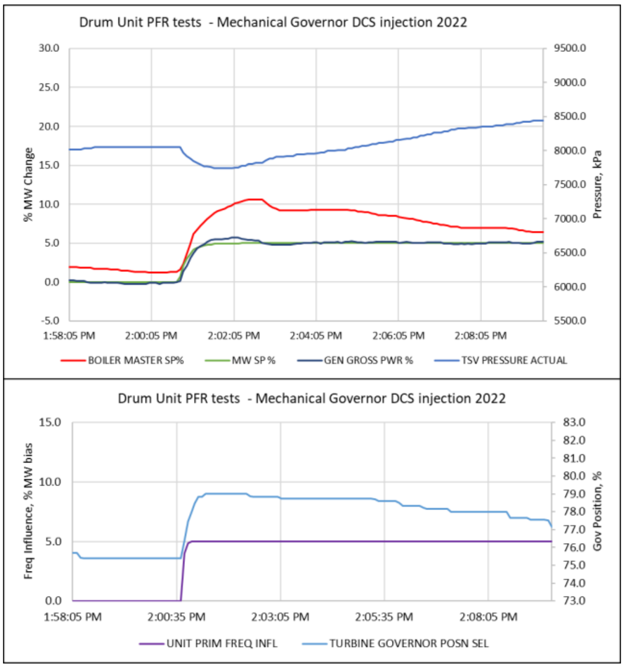


Figure 6 PFR step test by DCS injection (mechanical governor).
Note large initial movement of Boiler Master and Governor compared with 'settled' value.

When all these small effects continue in a cyclic manner as frequency limit-cycles around either the upper or lower PFCB limit, continuous movement with a high level of reversals can cause excessive wear of control devices and affected materials.

Taking the 20s cycle effect as an example: well-optimised control actuators typically move at no more than 10 movements per minute under normal conditions, or more often during disturbances and fast ramps. Minimum positioning of electric actuators, for example, is around 0.3% of the range. If each 20sec PFR cycle at the deadband's edge requires 1% movement of a particular boiler actuator, this adds 6 ramps per minute with up to 3 movements per ramp, or an extra 18 movements per minute, increasing actuator activity by 180%, significantly reducing the life of gearboxes, linkage joints and valve glands. While the life reduction may not be seen for several years, even small levels of PFR activity should not be considered to have insignificant long-term cost.

An example of this increased process activity is shown in Figure 7 that trends recent data from a large unit in the NEM. Note increased activity of fuel flow, furnace pressure and damper movement when PFR is active. The periods shown with no PFR action are due to the unit being at minimum load and so 'lower' PFR is not available when frequency is high.

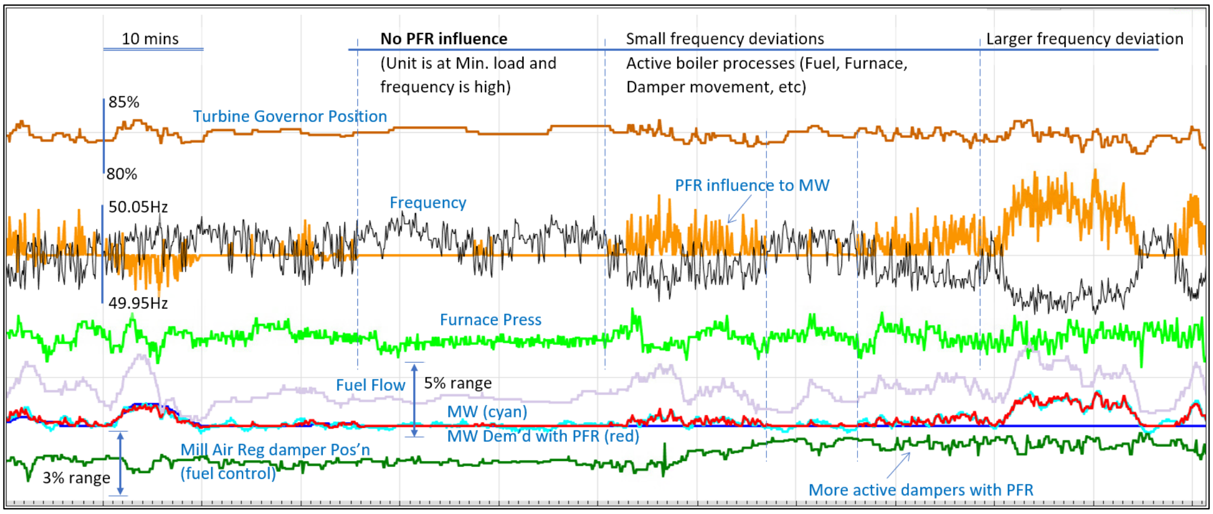


Figure 7 Trend showing comparative effect of small PFR influence on some boiler processes on a large unit in the NEM.

4.4 Control system resonances and effects on boiler combustion.

Several processes in Table 1 have fast time constants that can 'resonate' via the PFR response to cycling system frequency, or be 'kicked' by frequent random PFR demand changes. The most significant of these is Hot Primary Air duct pressure which supplies all mills with air. As a mill increases air flow in response to the PFR demand to the Boiler master (by opening its inlet damper), PA bus pressure falls and the PA fans respond, but with a delay. The two processes interact and can readily be sent into oscillation. The natural period of the coupled loop is similar to the grid frequency variations. Continued changes in mill air flow affects flame stability, a common issue particularly at the lower loads that units are now at for longer periods, and could increase carbon in dust (both efficiency and possibly loss of ash sales revenue) and NOx emissions.

The other combustion-related cost effect can come from concerns with flue gas O_2 (FGO2) which mush remain well in excess of zero to ensure safe combustion. If due to fast, regular PFR movement an addition movement of FGO2 causes occasional reductions from setpoint that are of concern, the

FGO2 setpoint will be raised. 0.5% FGO2 translates to 2.5% higher air flow, raising auxiliary power to FD and ID fans by a similar amount.

4.5 Significant increase in Turbine CV activity

The increase in throttle valve activity can be vividly seen in a trend of a NEM unit taken at the time the deadband was switched from 150mHz to 15mHz. The position range of fast movement reversals on CV 3 increased by at least 300%. AEMO reports in the white paper [1] that already by 22/10/22 several generators had moved to 15mHz PFR deadband and a significant reduction in frequency spread had already occurred, so this movement increase was not a worst-case example which subsequently reduced significantly. Also, trends taken over long periods later showed similar increases in CV movement and MW variations.

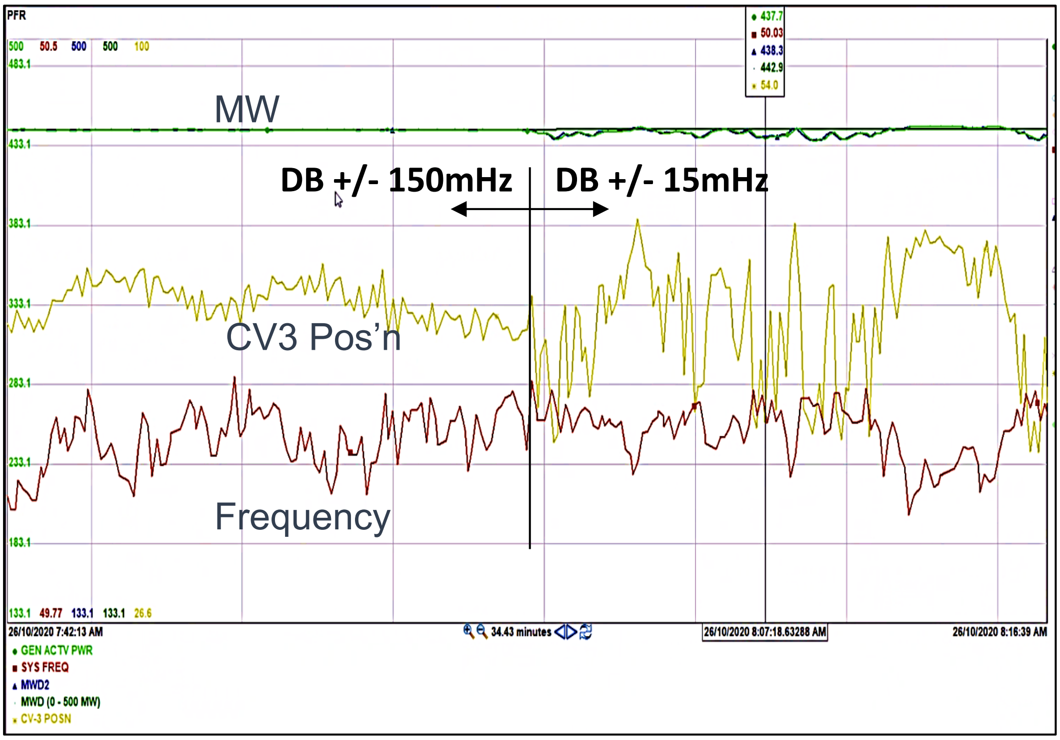


Figure 8 Example of turbine valve movement change when +/-15mHz MPFR was activated

[1] AEMO, *Enduring primary frequency response requirements for the NEM*, Technical White Paper, August 2021

[2] ERCOT, *Nodal Operating Guide*, March 2021, at http://www.ercot.com/content/wcm/libraries/226349/March_1_2021_Nodal_Operating_Guide.pdf.

[3] Goble, S. *Steam temperature control implementation at a coal-fired power station. Proceedings, ICEX 95, IICA.*

[4] Electric Power Research Institute, *Effect of Operational Transients on Boiler Damage*, 1015649, March 2009.

[5] Hübel, Moritz, A. Berndt, S. Meinke, M. Richter, P. Mutschler, E. Hassel, H. Weber, M. Sander and J. Funkquist. *"Modelling a Lignite Power Plant in Modelica to Evaluate the Effects of Dynamic Operation and Offering Grid Services."* Proceedings of the 10th International Modelica Conference, Lund, Sweden, 2014

[6] Alhelou H. H. Golshan M. H. H. Zamani R. Forushani E. H. Siano P. (2018). "Challenges and opportunities of load frequency control in conventional, modern and future smart power systems: A comprehensive review". *Energies, 11 (2497), 1–35.* doi:10.3390/en11102497 file:///C:/Users/dparker/Downloads/energies-11-02497.pdf accessed 08/20/21.