AEMO FPP Consultation Team
c/- Australian Energy Market Operator
GPO Box 2008
Melbourne
VIC 3001

(Lodged electronically via FPPconsultation@aemo.com.au) **6 December 2022**

FREQUENCY CONTRIBUTION FACTORS PROCEDURE
RESPONSE TO THE CONSULTATION PAPER
Date of Notice: 31/10/2022

Delta Electricity operates the Vales Point Power Station located at the southern end of Lake Macquarie in NSW. The power station consists of two 660MW conventional coal-fired steam turbo-generators.

Delta Electricity appreciates the opportunity to comment on the development of a new Frequency Contribution Factor Procedure (FCFP) to incentivise primary frequency response (PFR). Performance payments providing additional incentives for effective PFR are welcomed. There are, however, some practicalities of real-time conditions that affect monitoring trajectories that Delta Electricity offers comment to assist AEMOs design effort. The letter concludes with an attachment addressing the specific questions raised in AEMO's consultations paper.

Delta Electricity is concerned that frequency erraticism in the present NEM means that some frequency conditions are not controllable by the available PFR as currently designed. Incentivisation in this procedure should focus on improving adherence to target and support to a smooth frequency variation outside the period of some faster system variations presently uncontrolled which may actually need greater coordination efforts from central dispatch in the supply/demand balance and between uncoordinated unit control systems.

Delta Electricity is also concerned that the target trajectory proposed for the procedure will produce variations in performance results between trading intervals not always related to frequency and/or the PFR from individual units. It is considered that either the AEMO NEMDE/AGC targeting process needs modification or the procedure's target-to-target trajectory designed from targets adjusted to be always achievable by units subject to automatic control. If not done, there will often be trading intervals where performance results are actually reflective of the inadequacy in the unit dispatch expectation rather than inadequate PFR from a unit.

This letter provides real-time examples of regular dispatch depicting conditions with potential to produce inadequate results from this procedure if not well understood.

If AEMO wishes to discuss any details of this submission, please contact Simon Bolt on (02) 4352 6315 or simon.bolt@de.com.au.

Yours sincerely

Simon Bolt
Marketing/Technical Compliance

The Present Frequency Condition

A single generating unit is not designed nor reasonably expected to recover frequency of the entire system back to 50Hz on its own. All machines, in coordination with the reactions of all other machines and load as steered by a smart central dispatch from AEMOs NEMDE and AGC, can do this. Each mechanical-hydraulic governor reacts to speed changes before the unit load controller returns the Unit to dispatch setpoint. Unit FCAS controllers of a machine are designed to proportionally correct unit setpoint to provide the sustained response until frequency returns inside expected deadbands.

A mechanical-hydraulic governor reaction with supporting stored energy is a natural PFR delivery system i.e., the reaction provides a response in output proportional to the detected speed change according to the ‘droop’ percentage ratio. Therefore, Delta Electricity considers that a procedure aiming to incentivise PFR ought not produce causation from an evaluation of the natural responses of a Unit responding to conditions occurring in system frequency that are beyond the ability of the natural PFR design of the machine to control. AEMO are advised to ensure that the adopted frequency measure aims to track larger changes in frequency over longer time intervals (than 4s) than attempt to have addressed smaller changes occurring in a 4s timeframe. Frequency smoothed to avoid the regular 50mHz peak to peak changes that occur over a period of 25 to 30s is also recommended.

A unit correctly responding to Regulation FCAS should also not result in poor performance under this procedure. It may be that the procedure identifies some aspects of dysfunction between attempts to incentivise both regulation FCAS and natural PFR performance, but AEMO are urged to remember that prior to the transition to renewable energy, the natural PFR systems, supported by local DCS frequency control loops and previous non-market-based dispatch systems, were controlling frequency adequately.

An overly erratic frequency measure and/or inadequate performance trajectory deployed by the FCFP are considered to have potential to result in incorrect incentivisation outcomes if the natural mechanical-hydraulic governor reactions are not well understood and seemingly, under the developed procedure, result in consequential causation. Similarly, it seems inherently unfair if a unit’s correct response to regulation FCAS market dispatch results in PFR causation under this procedure particularly should regulation FCAS revenue somehow be outweighed by a negative net result in the PFR performance/causation arithmetic.

Targeting Dependence on Last Actual MWs

In any given day of present dispatch, the NEMDE/AGC regularly dispatches impossible targets for Vales Point Units to reach at the end of affected trading intervals (TI). These conditions appear to arise from the NEMDE/AGC system depending on the machine’s output MW condition as a basepoint, read in a single snapshot reading 20s before the end of a TI. The variability in unit output (potentially due to network conditions), the single snapshot used which is not necessarily averaged over the 4s preceding the snapshot (let alone being read and averaged over several 4s readings) and the delay between reading the output, the AEMO NEMDE determining the required next target and the commencement of dispatch delivery to Vales Point in the next TI, are all elements contributing to occasional impossible targets from the AGC.

Dependence solely on a single snapshot reading of machine actual output at the end of TI as a basepoint from which to determine the next TI target is the source of this error. The following points offer further insight:

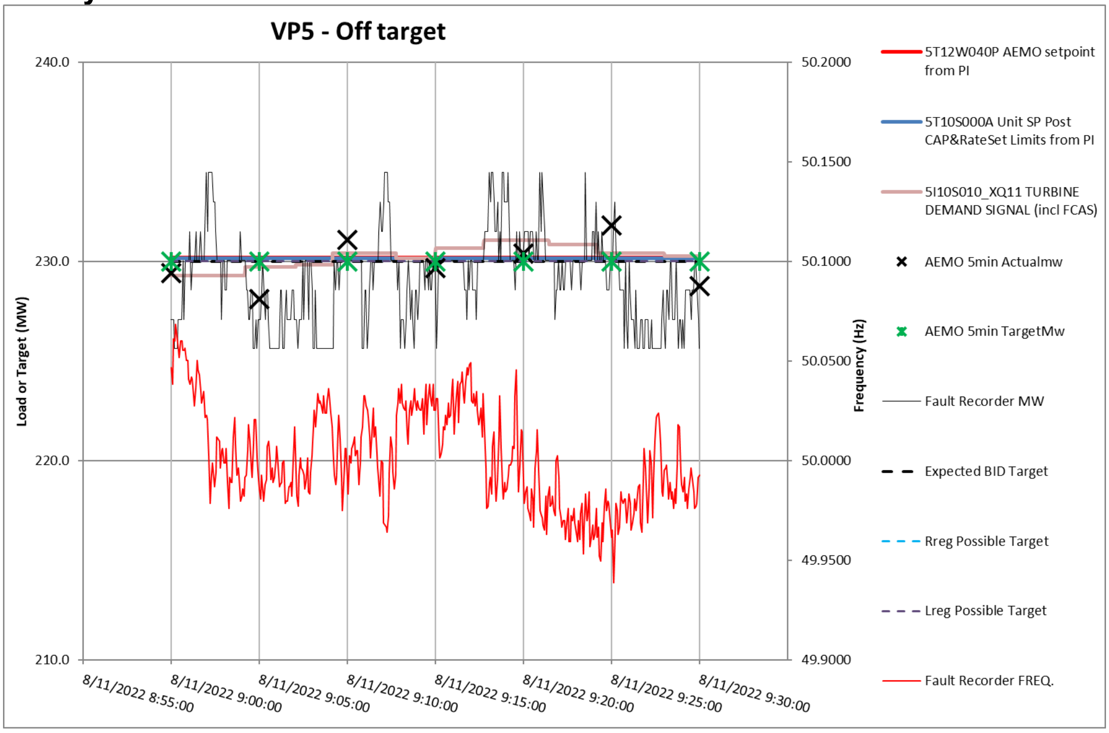
- The actual output is a result of the unit setpoint (prepared from AEMOs dispatch signal), PFR and network interactions and is therefore, generally, a highly variable signal; The unit setpoint may also include PFR but the continually produced local unit setpoint signal represents a steadfast signal driving the target the local Unit is trying to meet.
- The erratic nature of system frequency and the actual MW signal, which can be affected rapidly by system frequency, suggests that a single reading of actual MWs made 20s before the end of a TI is both too premature and too unreliable a basepoint upon which to determine targets from. An average reading over 20s ending at t=0 of the next TI may provide a better basepoint but the local unit setpoint developed in the Unit DCS from processing the received AEMO 4s AGC target signal, also sent back to AEMO every 4s, presents a superior basepoint upon which to develop the next target from.
- Quite separately to the possible variability due to system conditions, the Actual MW value is also a pure unfiltered output from the generator. A 4s reading on many units may be an instantaneous value not even an average representation over 4s that AEMO might be expecting it to be. The local Unit setpoint is a control signal driving the unit.
- The DCS rate of change (ROC) applied on an operating unit will usually be either at or above the rate of change of the energy bid. Unless maintained above the bid ROC, an assigned target that is more than 5 times the locally applied unit ROC from where the Unit setpoint is, when the next AEMO target arrives at the Unit early in the TI, cannot be met automatically.

For this procedure, if possible, AEMO should consider making some use of Unit setpoints, data that is also being returned to AEMOs AGC every 4 seconds, to confirm the assigned target-to-target trajectories are achievable by automatic control.

Some real-time trends, and comments about the observed conditions, are provided over the next few pages highlighting the conditions of frequency and errors that can occur in dispatch targeting that is reliant upon the highly variable single snapshot of Actual MWs. The trends depict:

1. AEMOs 5-minute target (green cross)
2. AEMOs 5-minute actual (black cross)
3. AEMOs target as received every 4s at Vales Point (thick red)
4. VP5 setpoint (Unit SP) produced locally and returned to AEMOs AGC every 4s (blue)
5. VP5 Turbine Demand – the signal that drives the turbine load setter (pink)
6. Unit output as recorded on the Unit fault recorder (black)
7. Unit output as independently recorded on the Unit control systems (thin brown)
8. Unit frequency as recorded on the Unit fault recorder (thin red)
9. Unit turbine rotor speed divided by 60 to provide an independent check that the fault recorder frequency and the detected movements in it is real. (thin cyan)

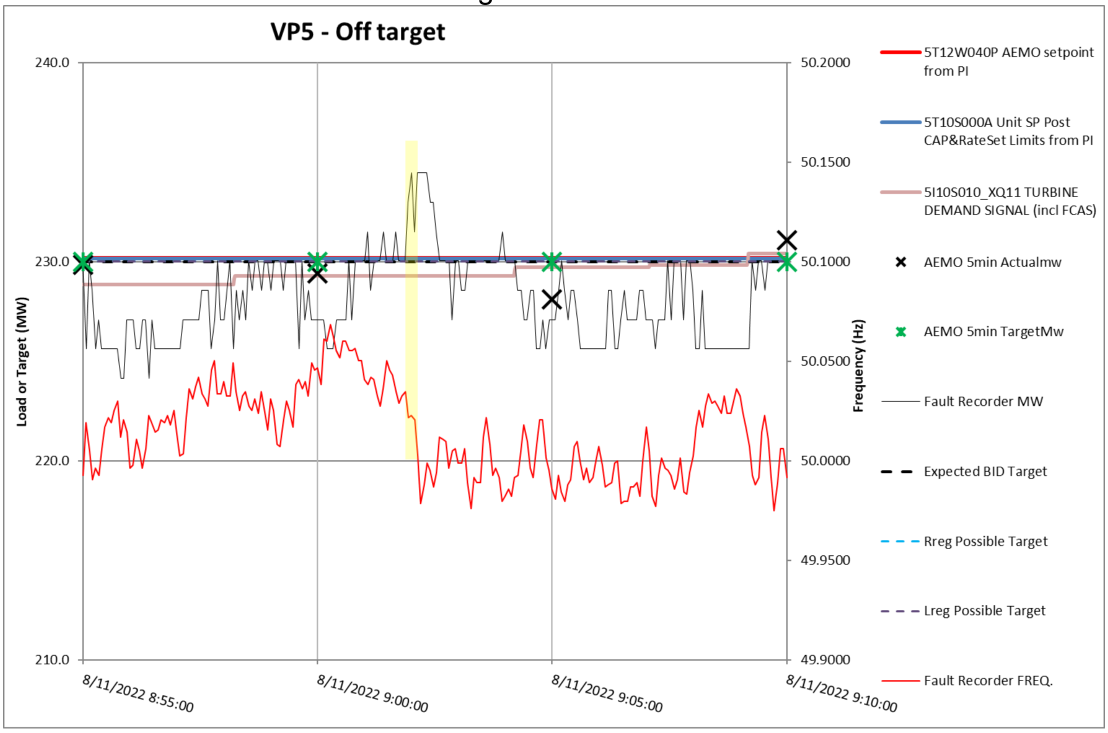
1. Steady Load



Comments on this 30minute snapshot of steady load dispatch on Vales Point Unit 5:

- The unit is dispatched to a steady load of 230MW
- Frequency and load can be seen to be varying. Some of the variation in load is PFR, some is plant related and some transient network reactions.
- Frequency exhibits slow larger changes in its average value that can be seen over minutes in this chart, and this is generally what is of interest to PFR incentivisation. However, it also has much faster movements (see next chart zooming in on the 09:05 TI)
- A single Unit is unable to govern completely what the system frequency does. It is the collective coordination of what all Units do and what the AGC does that is important in the overall objective to achieve a smoother and steadier system frequency.
- Mechanical-hydraulic governors react to rotor speed **change** and not an absolute frequency value as can be seen at 09:00 to 09:05 when frequency falls from 50.05 to 50.00Hz, an increase in load takes place. This is natural PFR. A change across a nominal 50Hz also occurs from 50.025 to 49.975Hz at 09:11 also displaying mechanical-hydraulic governing reactions.

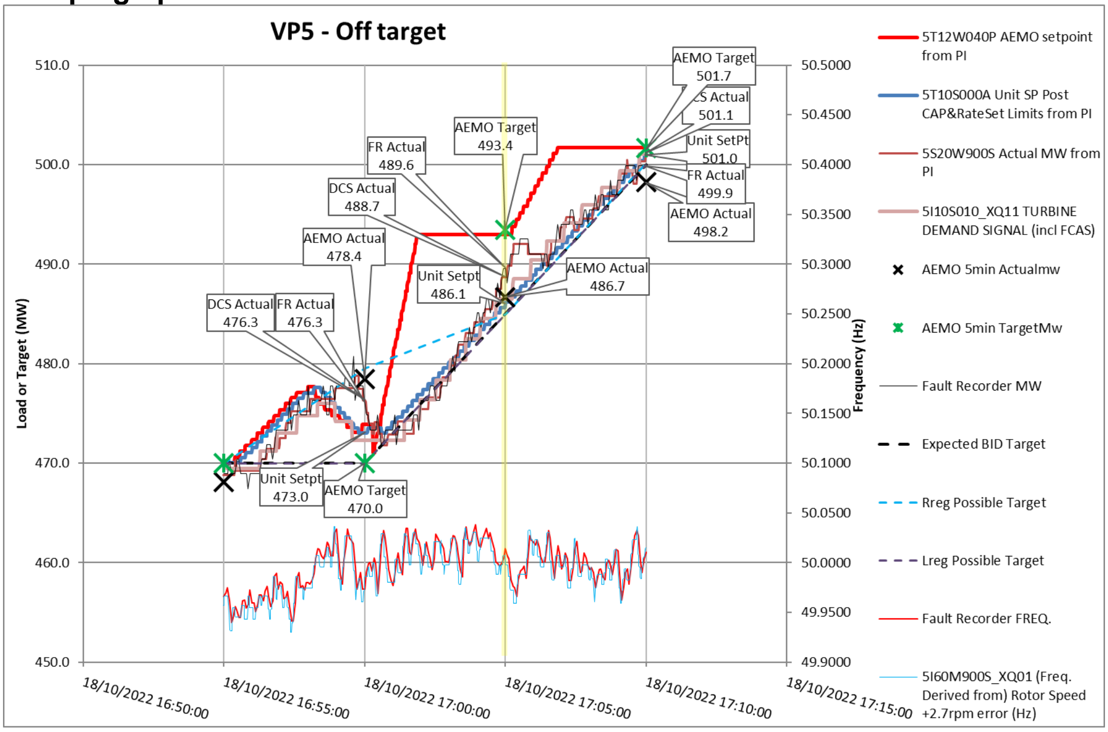
Here is a zoom into the 09:05 Trading Interval:



Comments on this view:

- At 08:59, output is at setpoint and target and frequency is above 50Hz.
- Frequency rises sharply producing natural PFR reactions reducing MWs.
- Frequency falls, sometimes sharply, from 09:00 to 09:02 producing some correction.
- The sharp frequency fall at 09:02 (highlighted in yellow), crossing the nominal 50Hz point, shunts output above setpoint even though it is a natural PFR reaction. In the target-to-target trajectory equation being proposed, the movement above setpoint might be considered causation whilst frequency is above 50Hz when the movement is natural PFR from a mechanical-hydraulic governing system.

2. Ramping up in Load

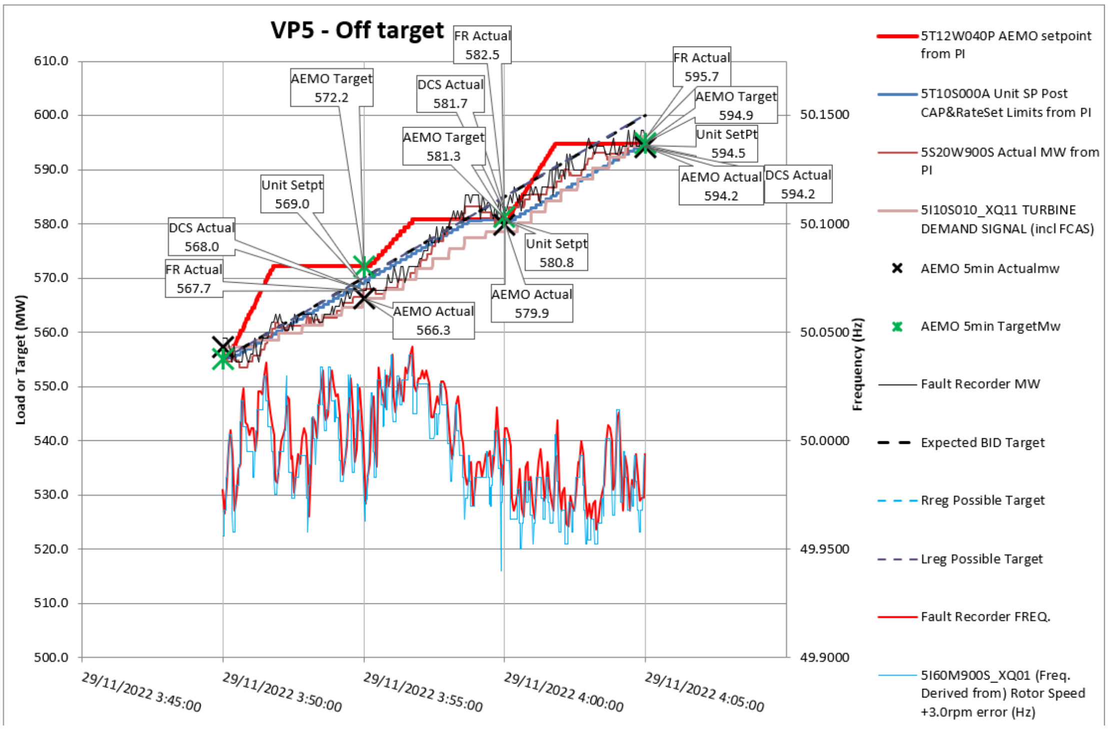


- Frequency derived from rotor speed is included in this chart cross-checking the frequency value and demonstrates that the variability of locally experienced frequency is genuine.
- Rapid 50-100mHz variations are apparent on the recorded frequency data but frequency in the 17:05 and 17:10 TIs is approximately averaging 50Hz. Natural PFR will be responding to some but not all of these variations and the speed they change presents a problem for natural PFR to correct.
- The unit target at 17:00 is a steady load of 470MW.
- Raise Regulation FCAS of 9.5MW is dispatched to the unit during the 17:00 TI, as shown in the red trace. The Unit setpoint, shown in blue, follows this dispatch.
- If the real time frequency and a target-to-target trajectory is being used to determine performance or causation, the early stage of the 17:00 TI appears OK: frequency is below 50Hz and the raise regulation FCAS takes effect and represents good performance.
- At the latter stage of the 17:00 TI, the frequency drops below 50Hz a couple of times. Unless the frequency measure can be selected to avoid it, the raise regulation FCAS and governor reactions will be penalised for this even though they are PFR delivery that is:
    1. Partially AEMO driven (Regulation FCAS remains in effect), and
    2. Natural PFR reaction (mechanical-hydraulic governors react to speed change even if the starting point for frequency is above 50Hz).

- Raise regulation FCAS dispatch ramps down from a peak near 16:58 but dispatch has not fully returned to the 470MW level by 17:00 and the governor reaction to previous sharp drops in system frequency continues additional support energy a bit longer.
- At the end of the 17:00 TI some of the hangover of the raise FCAS regulation and governor reactions, which is PFR, will be causation measured against any assigned trajectory with system frequency being so variable around nominal 50Hz. If possible, assigning a frequency measure that reduces or eliminates these sorts of effects arising from such variability is preferred.
- The AEMO AGC reads the Actual MWs for the end of the 17:00 TI from which NEMDE and AGC set the 17:05 target at a target value impossible for the Unit to achieve automatically. A manual adjustment to the Unit DCS ROC could assist but the target is really an incorrect assignment all conditions considered.
- Prior to arrival of the next AEMO dispatch early in the 17:05 TI, the local unit DCS, driving the machine to the unit setpoint via the turbine demand signal, corrects the unit back to the unit setpoint.
- There is no raise regulation FCAS dispatch for the unit during the 17:05 TI.
- A target-to-target trajectory will work reasonably well near the start of the 17:05 TI. However, the target-to-target trajectory line increasingly strays from being a good guide of possible performance towards the end of the TI and, by 17:05, performance compared to the target-to-target trajectory is generally disconnected from being related to PFR performance/causation. Instead, due to reasons previously explained, the trajectory, continues the errors from the previous TI becoming less precise as a performance guide.
- For the 17:05 TI, if Unit output was measured against a trajectory designed from a point A, the Unit setpoint at 17:00 (473MW), and point B, a point 15MW above (488MW), it would represent a better 17:05 performance monitoring trajectory for frequency contribution performance. (Note: the off-target at 17:05 reported by AEMO’s operational dispatch conformance monitoring is also inappropriate for this event because, despite the impossible ramp assigned by NEMDE/AGC dispatch, the true Unit MWs at 17:05:00 is improved upon what the AEMO AGC read at 17:04:40, 20s prior. The unit position improved to within the operational system margin for error)
- The 17:10 TI, perhaps a carry-over from earlier errors, presents a target-to-target trajectory simply incorrect across the whole TI. To correct this trajectory, Point “A” of a trajectory line would be better being the Unit setpoint or the Unit Actual at 17:05 and not the 17:05 AEMO target. A better correction would be correcting the 17:05 targeting error as mentioned above. If the AGC changes that might improve this are outside the scope of this project, another way to achieve this for the procedure is to include a comparison of the assigned NEMDE/AGC target to a calculated value 5 times ROC away from the unit setpoint and limit the point “B” of a procedure’s trajectory line. The AEMO NEMDE/AGC system appears to assign ramping targets 5 times ROC from a last actual MW basepoint. The highly variable Actual MW signal, the singular snapshot the AEMO NEMDE process relies on, and the delay between reading the actual and the time it takes before the next target

commences delivery to the Unit in the next TI, all collectively compound the errors for resultant target-to-target performance trajectories. If the point “B” of a trajectory line used in the procedure was not permitted to be more than 5*ROC from the unit setpoint at the start of the TI, a target-to-target trajectory target line in the procedure will be appropriate. Unfortunately, the same is not possible for a target determined from the Unit actual MWs as a basepoint. Target-to-target trajectories from this design are regularly impossible for a unit to achieve in automatic control.

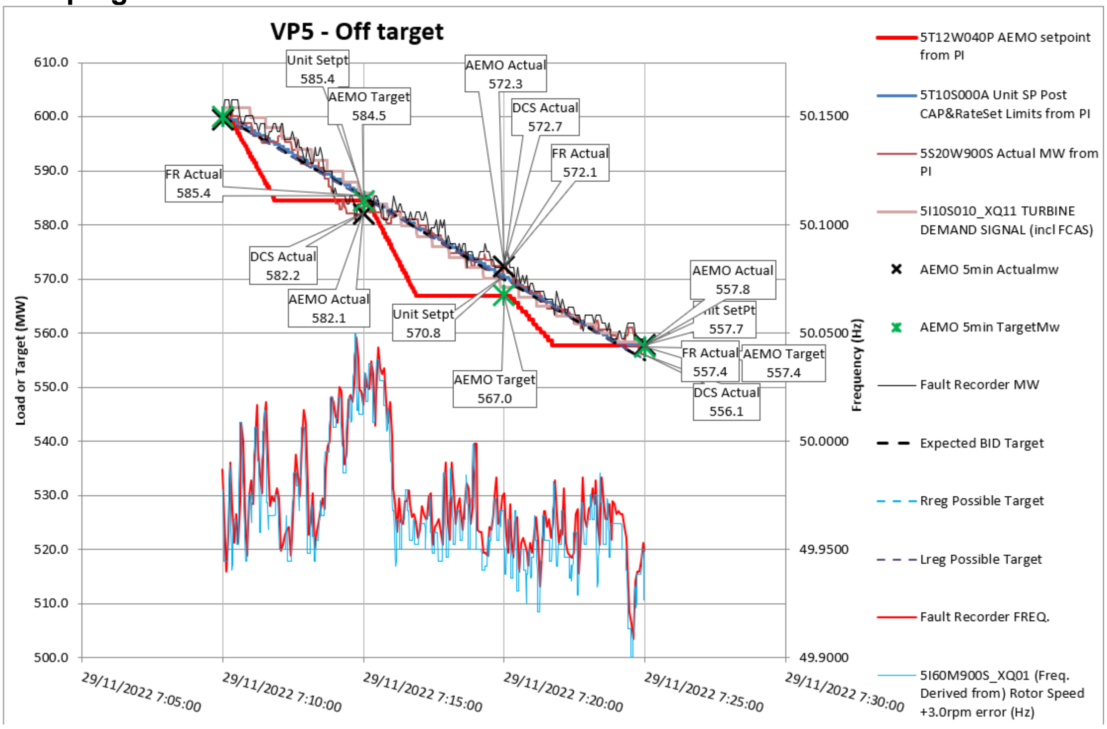
Here is another ramp up example but instead of the actual MWs being above the Unit setpoint at the start of the TI, the Unit setpoint is above the Actual MWs:



- the actual MWs as recorded by AEMO at the end of the 03:55 TI is 566.3MW so the next target is 581.3MW.
- At 03:55, Actual MWs is also below the unit setpoint, but recovers and returns to setpoint as delivered to the turbine load setter by the turbine demand signal (The turbine demand signal is produced by the local controller in response to the unit setpoint, which is itself formulated by the DCS from the AEMO dispatch target) during the 04:00 TI.
- At 03:59, the unit setpoint reaches the assigned target from AEMO. There appears to have been capability for the Unit to have delivered on a 15MW ramp up from the Unit setpoint as experienced at 03:55 which was 569MW to a target of 584MW instead of the 581.3MW.
- This example simply demonstrates how driving the AEMO NEMDE/AGC from a Unit setpoint basepoint instead the highly variable Actual MW at the end of the last TI, would achieve a smoother and more correct dispatch result.
- However, there is also an argument for the AEMO NEMDE/AGC basepoint assignment process becoming flexible and assigning the most appropriate

basepoint from the available unit data that achieves the easiest target assignment for a Unit. Both the Unit actual MWs and the Unit setpoint are returned to the AEMO AGC via SCADA every 4s to allow a simple check to be performed to formulate a smarter dispatch from the NEMDE/AGC.

3. Ramping down in Load



- There are no operational off targets experienced here but the same targeting inadequacy from the dependence on the highly variable actual MW signal are apparent.
- The 07:15 result (AEMO AGC reads the actual as 582.1MW) is below target due to PFR (caused by a sharp rise in frequency during 07:13). The unit setpoint is at 585.4MW.
- The 07:20 assigned target, based on the Actual result of 582.1MW is assigned as 567MW, 15MW below the actual.
- The Turbine Demand signal, generated from the local unit setpoint, directly controls the Unit continuing the previous ramp down adjusted by the new AEMO target delivered from the AGC, but observing the local control system ROC can only realistically permit the Unit target to go as low as 570.4MW.
- Variations from target-to-target trajectories from 07:15 to 07:20 and from 07:20 to 07:25 are therefore not PFR related. Instead, they result from inadequate NEMDE/AGC targeting.
- At 07:24, the unit setpoint reaches the assigned target from AEMO. The Unit could have delivered on a 15MW ramp down from the 07:20 Unit setpoint of 570.8MW to a possible target of 555.8MW.

Delta Electricity considers that the NEMDE/AGC basepoint assignment and the dependence on a snapshot SCADA reading taken of the unit actual MW output 20-

30sec before start of the interval regularly results in inadequate targets (for numerous 5-minute TIs per day). Target-to-target trajectories based upon this inadequate targeting is a source of concern for the effectiveness of this new procedure.

ATTACHMENT – CONSULTATION PAPER QUESTIONS

Frequency Contribution Factors Procedure Consultation – October 2022

Consultation Paper Questions

Organisation:	Delta Electricity
Contact name:	Simon Bolt
Contact title:	Technical Compliance
Contact details:	simon.bolt@de.com.au ☎0418 663 110

3.4 Issues for Consultation	
3.4.1 Frequency Measure	
•	Are there any alternatives to the proposal that would provide demonstrably greater net benefit to the market than regional measurement?
Response: Regional is probably better than global but some possible regions e.g., the entire state of Queensland, may benefit from having more than one region (which may be what AEMO is intending) particularly if there are known network challenges from long transmission or distribution corridors between Generation and Loads.	
•	What process should AEMO follow to change the weighting of parameters for the frequency measure?
Response: The weighting of parameters could be listed within the procedure and determined via consultation. However, if such parameters will define or limit the outcomes of the incentives that the procedure will offer and different options produce great variability, a more independent check via the Reliability Panel, for example, to confirm the resulting incentives are what the market prefers might be worth considering. AEMO unilaterally determining the weighting is another possible method, but such a path probably then determines that AEMO will be independently responsible for the result.	

- How should AEMO assess the efficacy of the frequency measure and weightings?

Response:

The statistical condition of system frequency itself presents the best guide. However, it is considered that PFR incentives alone will not necessarily produce the steadiest frequency possible. Better overall coordination is considered to require central coordination by AEMO and scrutiny of interactions between the AGC and each participant and between various participants e.g., A single unit of one participant closely connected to a large capacity of MWs from a group of Units from another participant may develop poor performance in reaction to a poor frequency control design from the larger group of Units. PFR incentivisation will not be able to fix these problems. AEMO should focus on what sort of improvements to system frequency they are hoping for and develop reasonable monitoring targets and include these in the reporting metrics.

3.4.2 Contribution Factors

- Feedback is sought on the proposed formulation for determining contribution factors in the FCFP. Do you see any issues with the proposal?

Response:

The Target trajectory should be determined with limitations to ensure that the assigned target for the Trading Interval, is achievable by the Unit. There are many intervals where the NEMDE and the AGC targets are inadequate and whilst it may be AEMOs preference to fix this in the AGC (outside of this project), the targeting trajectory used in the Frequency Contribution Factors Procedure could also be built to overcome this inadequacy. It may be better to either correct the targeting process before this procedure takes effect or, if not possible, ensuring the target-to-target trajectories used in the procedure adjust each TI target to that achievable by a Unit. Applying trajectories that are not achievable by units will not incentivise and will be reason for complaint and confusion in particular Trading Interval results.

- AEMO is assessing possible timeframes for determining average performance for historical default contribution factors. This could be, for example, an eligible unit’s average raise or lower performance for a period of a week, or as in the draft FCFP, a certain number of trading intervals for which there is valid raise or lower performance values. What principles should AEMO have regard to in determining this?

Response:

Performance could be the result of seasonal and time of day conditions. There may be a benefit in having schedule of performance factors for each Unit drawn from historical conditions but if the intention is to keep it simple, a schedule produced from historical four-week sub-factors (LEF, LNEF, REF, RNEF) for each unit from the current system would be a starting point. This history has some advantage in that at least the factors are already normalised, averaged and relative between Units to overall conditions.

•	In determining default contribution factors should AEMO exclude good performance or, as in the draft FCFP, should it be a simple average of all performance?
Response: Unless the trajectory will be mindful of the errors that can occur in the generation of the next target from a last actual read 20s before the end of the previous TI, there will be many periods where good performance and bad performance will be adjacent through no fault of the operating unit so , if the trajectory is not going to prevent inappropriate trajectories being used, it will be necessary to consider both good and bad performance to work towards default contribution factors. If the targeting trajectory can eliminate the potential for utilising impossible targets, it may then be possible to concentrate only on the poor performing periods.	
•	What specific circumstances are there where default contribution factors should apply automatically that should be explicitly captured in section 5.3 of the draft FCFP? Where should AEMO have discretion to apply default contribution factors?
Response: If the frequency measure utilised is significantly out of alignment with local frequency conditions, in a similar way to how the existing procedure checks for FI being opposite in sense to reactions expected from local frequency, this is one circumstance. However, the determination of the frequency measure will hopefully reduce the occurrences of this in any set of 4s samples in any Trading Interval.	
•	How should offline units contribute to the cost of regulation FCAS? Are there circumstances (such as being offline for an extended period of time) in which a unit should cease being liable and be given a default contribution factor of zero? If so, how should AEMO determine a unit to be offline?
Response: If a Unit goes off-line but has not yet rebid for this condition the system should continue to be consider such a unit on-line as the market will consider them available until the bid is adjusted. Off-line Units should continue to contribute towards costs of regulation FCAS until the rebids are processed. However, from a control perspective, when units go off-line suddenly it is true that in the immediate aftermath there is probably a benefit to the NEM from faster reassignment of frequency control drivers to enable other sources to replace that lost from the unit that is suddenly off-line. Other status indicators may exist for some Units upon which to base a faster reaction for more advance reassignment of Contingency and Regulation FCAS and energy dispatch. In specific cases, such signalling may come from the participant but in others may come from the TNSP which the Generator is connected to.	

3.4.3 Requirement for corrective response

- Should the requirement for corrective response be capped in certain circumstances? What should those circumstances be?

Response:

No capping is required but it is important that the frequency measure be smoothed so that the procedure and resultant performance/causation is only relative to controllable PFR. The present frequency conditions contain movements that are not controllable by PFR and these movements should be removed from the frequency measure.

- Is the use of a simple maximum value in MW for a 4-second period within a trading interval ideal? What other options are there that meet the rule requirement, and how should AEMO evaluate them?

Response:

A simple maximum is probably best in the first instance of this new system. With the benefit of experience and real-data assessments, an alternative may evolve.

- Should minimum thresholds apply to the calculation (for example, a minimum number of consecutive raise or lower 4-second intervals before a 4-second interval can be used to potentially determine RCR, or a minimum frequency deviation required to set RCR?)

Response:

Designing the frequency measure to be smooth enough to avoid the more rapid movements not being controlled by PFR will probably overcome the need for minimum thresholds and would determine the minimum frequency deviation.

- Should some types of variable generation be aggregated for the purpose of calculating RCR?

Response:

No response.

- How should RCR be calculated for global requirements when there are two AGC areas (e.g. Tasmania and Mainland)?

Response:

No response.

3.4.4 Usage of regulation FCAS

- Are there any preferable alternatives to the draft FCFP formulation of usage?

Response:

Delta Electricity does not have any preferable alternative at this point in time.

- Referring to section 7.3 of the draft FCFP, are there any circumstances in which usage should be defined as being equal to zero, for which the requirement for corrective response should not also be zero? In other words, are there any scenarios in which frequency performance payments would not be made, but for which regulation FCAS costs should still be allocated in part to eligible units on the basis of measured frequency performance during that trading interval?

Response:

Delta Electricity cannot think of any. Theoretically, proportional systems will be trying to provide support based on detected conditions. It is likely, and demonstrable from evidence of mandatory PFR delivery, that performance payments are warranted in all periods even if FCAS regulation is not at very high dispatch levels. The quantity of PFR is considered to be typically ten-fold that of regulation FCAS and so it is actually possible the reverse applies that there could be some times when no or very minimal regulation costs may be allocated but the PFR reaction is large. Performance should always be respected and acknowledged in the procedure.

3.4.5 Reference Trajectory

- There is a lag between the start of the trading interval and when AEMO sends out a dispatch instruction. If this impact is deemed to have a material impact on contribution factors, what are the options to address it?

Response:

It is preferable to improve the accuracy of the targeting system and the trajectory system. As the latter depends on the former in that the next target needs a basepoint reading from which to be determined, this lag, and other targeting decisions, collectively impact on the correctness of the target-to-target trajectory.

From the perspective of Unit control, the lag has two components:

1) the time when the basepoint is read which is before the start of the trading interval (20s from the end of the previous TI) and

2) the time when the next target starts to arrive in the Unit DCS (there are probably other factors within the NEMDE and AGC in terms of what is possible).

The theoretically perfect delivery would see the basepoint be read, next target determined and start to be delivered all at time t = 0 of each TI.

The options may include:

- reading the basepoint over a longer interval (presently understood from AEMOs AGC and NEMDE specialists, to be read in a single snapshot 20s before the end of a Trading Interval)
- choices as to what signal to read the basepoint from whether it be an Actual MWs or the local Unit setpoint. The actual MWs will generally be subjected to Network variations and PFR whereas the Unit setpoint is a steadier control signal driving a unit but, with MNBPFR PFCB at a tight setting of +-15mHz, can still vary due to PFR reactions also.

- Should units that are enabled to provide Regulation FCAS be treated differently? If so, how?

Response:

Regulation FCAS Units should be paid for Regulation FCAS and be included for PFR performance payments and causation costs but should not have a resultant transaction for both that represents an overall expense unless demonstrably failing in the regulation FCAS dispatch. The design of the frequency measure and the way the frequency input is smoothed will be critical in this consideration because evidence exists that regulation FCAS dispatch is generally slower in application on a Unit than PFR reactions. System frequency might require a reaction opposite to that driven by a Unit observing regulation FCAS dispatch particularly when dispatched on a steady energy target. A procedure considering performance against a target-to-target trajectory may need to consider the regulation FCAS performance with the PFR performance/causation payments/costs for a trading interval and ensure it does not produce a negative result. It is suggested that the FCAS/PFR Net result should consider a comparison something like:

Maximum(0, (PFR performance - PFR costs) + FCAS Regulation Income).

In other words, a compliant regulation FCAS provider should not incur an overall net financial loss from PFR causation in a TI. It would be better if the procedure is designed so that the PFR performance cannot produce a causation outcome for a Unit correctly observing FCAS regulation dispatch.

3.4.6 Calculation of the Residual

- Are there any complications with this approach that have not been raised?

Response:

No response.

- Would it be preferable for the impact of interconnector deviations to be borne entirely by the local residual for local requirements? This would enable the ~~the~~ framework to have good and bad performance for appropriately metered units to offset (since the link between deviations and cost would remain intact).

Response:

Interconnector variations present conditions to either region that are similar to that of a load or generator but the cause for the variation on the interconnector are many and varied so it does not seem reasonable to have the local residual bear the impact exclusively unless it is expected that the opposite impact occurs on the adjacent region and its local residual.

•	Should contribution factors for the Residual be capped at zero? (noting that default contribution factors for eligible units that are appropriately metered are capped at zero)

Response:

As the residual is unmetered it seems appropriate to cap it at zero because without more elaborate metering from which to generally determine good PFR is occurring positive factors seem random and would erroneous in the objectives for incentivisation of those participants that can adequately demonstrate performance.

3.4.7 Estimated contribution factors in the Predispatch timeframe

•	Do you see value in AEMO publishing estimated aggregate values in the Predispatch timeframe?

Response:

Any data that can assist participants improve understanding of exposure to PFR local requirements is considered valuable.

•	What other data do you consider worthwhile for AEMO to publish?

Response:

The frequency measure.

The x and y weighting factors and reasons for them.

The reasoning behind the dispatch quantities for Regulation and contingency FCAS.

Any AEMO estimates for the minimum quantity of PFR required to maintain the expected histogram shape for frequency control in the NEM.

AEMO targets for frequency performance over and above that required by, or those not include within, the FOS, and routine performance of real conditions measured against those targets.