31 October 2019

Attention: Ben Hiron
Australian Energy Market Commission
SYDNEY
**Submitted online to:** www.aemc.gov.au

## Response to Primary frequency response Rule changes (ERC0274)

CS Energy welcomes the opportunity to provide a submission on the AEMC consultation on the AEMC, Primary frequency response Rule changes, Consultation paper, 19 September 2019 (**Consultation Paper**).

### About CS Energy

CS Energy is a Queensland energy company that generates and sells electricity in the National Electricity Market (**NEM**). CS Energy owns and operates the Kogan Creek and Callide coal-fired power stations. CS Energy sells electricity into the NEM from these power stations, as well as electricity generated by other power stations CS Energy holds the trading rights to.

CS Energy also operates a retail business, offering retail contracts to large commercial and industrial users in Queensland, and is part of the South-East Queensland retail market through our joint venture with Alinta Energy.

CS Energy is owned by the Queensland government.

### General comments

CS Energy supports the consultation being undertaken by the AEMC. The AEMO proposal has correctly highlighted a need for Primary Frequency Control (**PFC**) to deal with minor deviations in frequency and extremely large deviations in frequency, such as those experienced under islanding conditions.

CS Energy considers that the underlying reasons for why generators don't provide PFC in response to minor deviations are different to those reasons for failing to provide PFC in response to major, extreme deviations.

CS Energy's view is that there is no PFC dealing with minor deviations because it costs money to provide narrow band response (e.g. within +/-0.15Hz) and yet there is no compensation provided.

The same isn't true for major, extreme deviations, because the costs imposed by responding (wide band response) are less than the costs of not responding (unit trip, black, forced shutdown, equipment damage). CS Energy submits the lack of wide-band (e.g. outside +/-0.5Hz) PFC is caused either by the ability for some participants to free ride on a shared grid or simply because some participants do not understand it is in their interest to provide that response.

It is therefore unhelpful to conflate the two. Additionally, the AEMO proposal is a 'partial' mandate and therefore it is not a perfect solution to either of the problems.

*Narrow band PFC*

The direct way to encourage narrow band PFC is to provide appropriate compensation for its provision. A full mandate with units' preserving capacity, would force suppliers of the PFC to pay for it (instead of the consumers of frequency control services). CS Energy does not endorse this.

Instead, CS Energy recommends a financial incentive be implemented. The financial incentive uses an additional double sided 'Causer Pays' arrangement. This is explained as 'Pathway 2' in the Attachment to this submission.

If the AEMC is minded to implement the partial mandate, CS Energy suggests this mandate could be improved with a double-sided compensation regime. This should allow providers to preserve capacity for PFC and be compensated for doing so as well as introducing a financial incentive on participants that adversely affect frequency. This is explained as 'Pathway 3' in the Attachment to this submission.

CS Energy supports either Pathway 2 or 3, (preferring Pathway 2), on the proviso either leads to a more permanent solution, such as the 'deviations' approach discussed in the Consultation Paper.

*Wide band PFC*

Implementing a partial mandate for wide-band (e.g. outside +/-0.5Hz) response would unlikely impose economic cost. In this case the incentive is already present as the cost of responding to major deviations is likely to be less than the cost of failing to do so. CS Energy recognises these risks and already voluntarily provides wide band response without the need for an additional economic incentive.

CS Energy supports a partial mandate for wide-band (e.g. outside +/-0.5Hz) response.

Our detailed response to the Consultation Paper questions is set out in the Attachment.

Yours sincerely

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# ATTACHMENT

## RESPONSES TO CONSULTATION QUESTIONS

## ISSUES RAISED IN THE RULE CHANGE REQUEST

### 1. Response to Question 1

> QUESTION 1: ISSUES RAISED BY AEMO IN ITS RULE CHANGE REQUEST, *MANDATORY PRIMARY FREQUENCY RESPONSE*
>
> In relation to AEMO's rule change request, *Mandatory primary frequency response*:
>
> - What are stakeholders views on the issues raised by the AEMO in its rule change request, *Mandatory primary frequency response*?
> - Do stakeholders agree with AEMO's assessment that regulatory change is required as a matter of urgency to restore effective frequency control in the NEM?
> - What are stakeholders views on AEMO's definition of effective frequency control as requiring narrow band frequency response from as large a portion of the generation fleet as is practical?
> - Are there any other related issues or concerns that stakeholder have in relation to frequency control during normal operation and following contingency events?

CS Energy considers AEMO's issues are multiple, but can largely grouped by those relating to general frequency control under normal conditions (sections 3.1.1, 3.1.2 and 3.1.5) and under extreme conditions (3.1.3, 3.1.4).

### 1.1. Frequency control under normal conditions – very narrow band response

Ignoring the extreme conditions, and first dealing with issues: section 3.1.1, (difficulties keeping frequency within +/-0.15Hz 99% of the time); section 3.1.2 (undamped frequency oscillations); and section 3.1.5, (difficulty comparing to and learning from other grids). These issues reflect the premise of the Rule proposal, being a technical issue requiring a technical solution. Interestingly the issues are framed about the activities of a system operator.

Whilst this kind of response is understandable it isn't helpful when discussing possible solutions. This is because the system operator's approach appears to address the symptoms rather than the underlying cause. If only the symptoms are addressed, the underlying cause may emerge with increased adverse impact.

The issues raised by AEMO are not in themselves reasons for regulatory change, but they may point to an underlying issue. So, what is the underlying issue?

3.1.1 explains a failure to keep the frequency within the Normal Operating Frequency Band ('NOFB') 99% of the time, especially during January-March 2019.

Since that period AEMO has increased the Regulation FCAS amounts (categorised as secondary control services), with frequency being in the NOFB more of the time, yet AEMO has stated frequency control and stability within the NOFB has not improved.

CS Energy accepts that purchasing more secondary control services will, more likely than not, reduce the instances where frequency is outside the NOFB, but will not improve frequency control and stability within the NOFB. CS Energy agrees with this statement by AEMO.

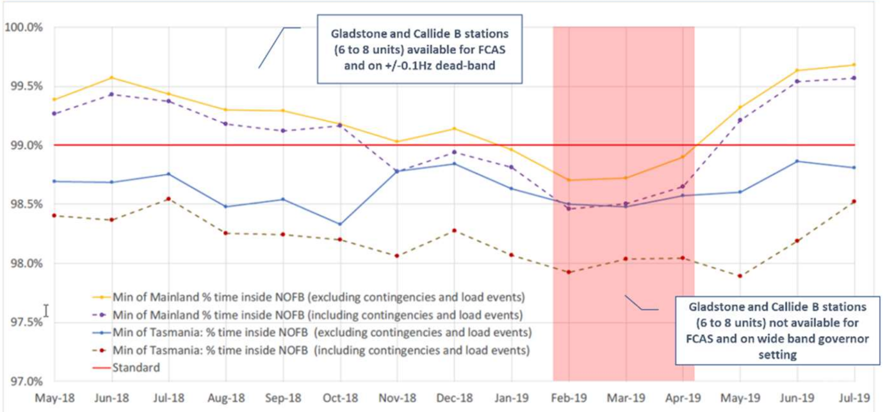
However, contrary to the implication of the Consultation Paper, CS Energy considers the improvement in frequency performance since April 2019 is <u>not</u> solely attributable to increases in secondary control quantities. This is because during the period where the 99% target was not met, there was little incentive to provide narrow band PFC, especially from units that might provide PFC at +/-0.1Hz when made available for contingency FCAS. This was because of:

- low contingency FCAS prices and competition from switching loads;
- the refinement of the reclassification of QNI as a credible contingency under lightning conditions; and
- strong financial incentive to provide secondary control following AEMO's retuning of the AGC system in November 2018.

The figure below is taken from the Consultation Paper. Given the date appears to be a 'rolling' average, the labels (e.g. "Feb-19") are ambiguous as it may refer to the

30 days prior to the 1st of the month (i.e. the month preceding). Whilst the timings are not exact, CS Energy notes the incentives to provide voluntary narrow band PFC with a dead-band of +/-0.10Hz when also offering contingency FCAS were low; instead the incentive was for units to focus on energy services and providing secondary frequency control through Regulation FCAS.

**Figure 3.2: 30-day rolling average of percentage of time frequency is within the NOFB**




Source: AEMO, *Mandatory primary frequency response* — Electricity rule change proposal, 16 August 2019, p. 23.

Since April 2019 incentives to provide some PFC within the NOFB have increased due to increasing FCAS contingency prices, as well as an increase in secondary control amounts being purchased by AEMO. Please note that if units are made available for contingency FCAS but not enabled by NEMDE, and recognising the units response is not linked to AEMO's EMS (so response is provided irrespective of whether they are enabled for contingency FCAS), then there is more PFC available within the NOFB, at +/-0.1Hz. This would assist meeting the 99% target of the Frequency Operating Standard within +/-0.15Hz.

This leads onto the discussion over undamped oscillations in the NOFB, section 3.1.2 of the Consultation Paper. The 'undamped frequency oscillations' within the NOFB have been evident and it should be noted that they are of long duration, with frequency moving towards one side of the NOFB, to approximately +/-0.1Hz where it settles for a while, then often moving rapidly (faster than regulation secondary control can respond) through 50Hz into the other side of the NOFB.

This data suggests a lack of primary frequency control within the range of frequency deviation +/-0.1Hz, resulting in largely uncontrolled frequency between this range and the observation of 'undamped frequency oscillations'.

This is certainly true of stations within CS Energy's portfolio. For those stations which are enabled for contingency FCAS, they must be selected to a 'narrow dead-band' +/-0.1Hz. In contrast, our units which are not registered for contingency FCAS are selected to a 'wider dead- band' ranging from +/-0.25Hz to +/-0.50Hz.

From CS Energy's perspective the lack of control within the NOFB and 'undamped frequency oscillations' are not an issue in and of themselves, but a symptom of an underlying issue which currently fails to recognise that **it costs generators to provide governor control and given they aren't paid for it, they don't.**

### (a) What are the costs of providing PFC?

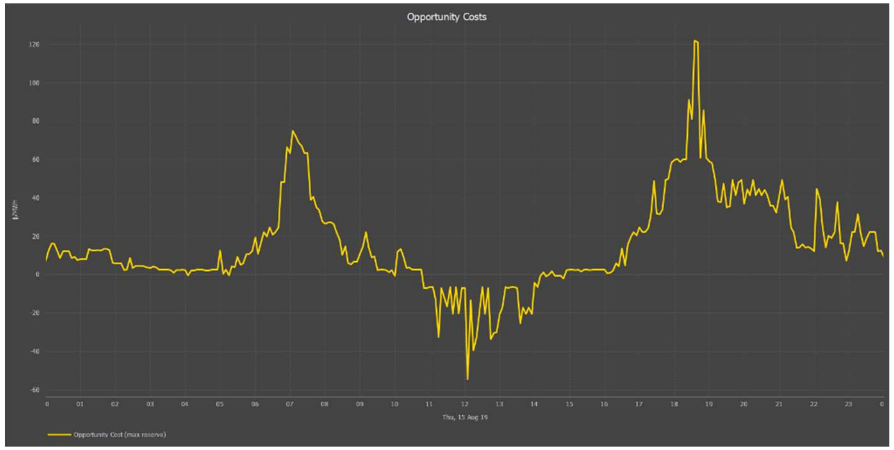
The costs include opportunity (capacity) costs and energy (utilisation) costs:

- ***opportunity*** costs, being foregone profits from preserving ***capacity*** for frequency response in lieu of increasing or decreasing dispatch; and
- ***utilisation*** costs, being profit or loss incurred from changing ***energy*** generation to improve frequency.

*Opportunity costs*

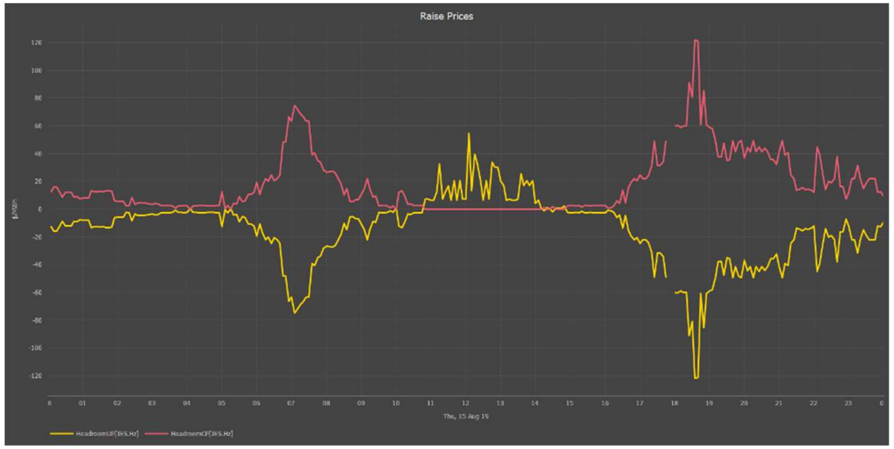
The opportunity cost estimates are based on the profits (or losses) a coal-fired generator may expect to receive from being dispatched. For example, should the RRP be $100, then a generator with a marginal cost of $55/MWh will have opportunity costs (ignoring any change in price for change in volume) of $45/MWh.

The following chart presents the opportunity costs for a $55/MWh generator on the Mainland.

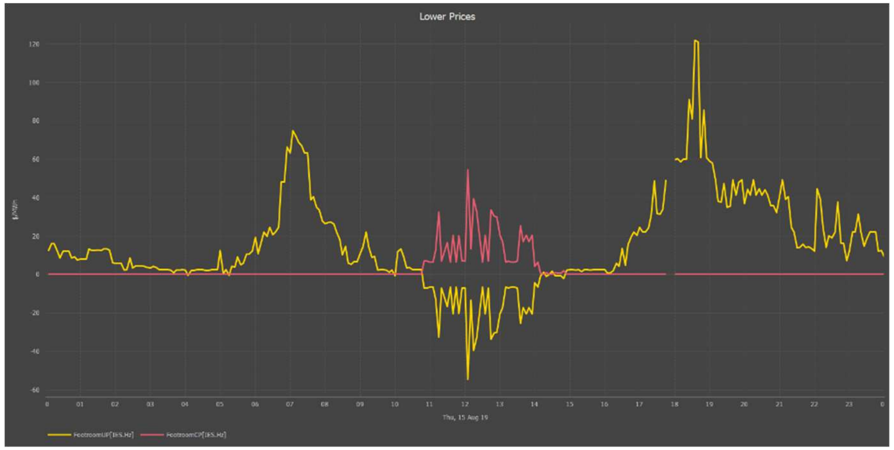



*Capacity and utilisation prices*

If the opportunity costs are positive, then the headroom for raise 'capacity price' is positive as this is the volume that represents an opportunity loss for the generator. Should however frequency drop and the generator increase dispatch, it profits from the increase in dispatch. Therefore, the utilisation price is negative (a deduction from the cost of preserving the headroom). The prices are presented in the following charts




Capacity prices can only be positive. Utilisation prices can be positive or negative. For example, if opportunity costs are negative (RRP<$55/MWh) then preserving headroom has no value yet increasing dispatch to correct low frequency results in the generator incurring a loss.




### (b) Is there a market for Primary Frequency Control?

If one assumes 'consumers' are willing to pay (up to a price) to control frequency within the NOFB and want to remove 'undamped frequency oscillations' whilst at the same time producers are willing to supply the service (at a price), there is demand of frequency control services not being met by supply.

'Consumers' should be considered in the broadest possible sense, not someone consuming electricity, i.e. a household or company, but someone or something affecting frequency.

If grid security services aren't priced, grids operate worse than they should, or in a costlier manner, with the wrong grid participant paying. In the case of the NEM, why would one expect grid frequency to be controlled close to 50Hz when no one is paying for it?

Worse still the elements of the grid that are consumers of these unpriced services don't pay, leading to inflated demand from these consumers, which in this case would further lead to a deterioration in frequency control[1].

In such a situation using price incentives to control the production and consumption of frequency services should be the ideal approach. Using price incentives will reduce costs for consumers, because amounts will not be purchased unnecessarily when the demand for the service is low and improve utility because more services will be purchased when desired. In theory the quality of frequency control should move to a level that consumers of the service are willing to pay, with this varying depending on the costs.

At present CS Energy operates several coal-fired units that have the capability to provide primary and secondary control services. Not all of these units provide FCAS under the current market arrangements, because some units are far cheaper at producing electricity than the others. The costs of profits foregone at our cheaper units are too high to make it competitive to our more expensive units in controlling frequency. Therefore, our cheaper units are not yet registered for FCAS. In effect the cheaper units are a consumer of frequency services and our more expensive units a producer of frequency services.

Ideally the NEM's dispatch, compliance and frequency control arrangements should allow liberty for participants to minimise costs and maximise profits, improving the consumer benefits from the NEM.

Services like primary frequency control, that can control frequency tightly under normal conditions aren't priced. Yet others, such as secondary control are priced. That the current frequency control arrangements don't allow this is the underlying issue and the issues identified by AEMO in the Consultation Paper are symptoms, rather than issues in themselves.

[1] CS Energy would posit this was the case until AEMO finally increased its expenditure on Secondary control AGC-Regulation in April 2019, where increased costs have been incurred.

### 1.2. Frequency control under extreme conditions – wide band response

The AEMO proposal raises the issues (in sections 3.1.3 and, 3.1.4) of more complex events, non-credible contingencies and reliance on Automatic Under Frequency Load Shedding (AUFLS).

It should be noted that CS Energy units not registered for FCAS provide wide range response at approx. +/-0.5Hz, largely because the benefit from doing so exceeds the cost in addition to Rules compliance as detailed in the Generator Performance Standard (GPS) and reflective of good operating practice: it is not in CS Energy's interest for these units to fail to respond to rare, extreme events which may result in units operating on under or over speed, because this would impose significant costs (and possible catastrophic equipment failure) on the generators.

This is particularly relevant for instances of very high frequency, (due to the absence of Over Frequency Generator Shedding Schemes (OFGSS) on the NEM Mainland in response to high frequency events), such as the 25th August 2018 event in Queensland with the trip of the Qld-NSW interconnector. On that day all of CS Energy units provided wide range response, containing the frequency within the Queensland electrical island. That other generators did not and choose not to provide wide range response is a surprise and of concern.

The underlying issue for the lack of wide band response for rare, extreme, 'major' deviations appears to be:

- the ability for some participants to free-ride;
- the potential for participants failing to understand the risks (and not acting in their own best interests); and
- any ambiguity on this subject being removed from the Rules and the GPS.

Whereas the issue for 'minor' frequency deviations is the missing economic incentive, in this case the incentive is already present: because the cost of responding to major deviations is likely to be less than the cost of failing to do so.

Based on this cost assessment, reflective of good operating practice and notwithstanding the ambiguity on this subject in the Rules and GPS, CS Energy voluntarily provides wide band response without the need for an additional economic incentive.

## 2. Response to Question 2

> **QUESTION 2: ISSUES RAISED BY DR SOKOLOWSKI IN HIS RULE CHANGE REQUEST, *PRIMARY FREQUENCY RESPONSE REQUIREMENT***
>
> - What are stakeholders views on the issues raised by Dr Sokolowski in his rule change request, *Primary frequency response requirement*?
> - Are there any other related issues or concerns that stakeholders have in relation to frequency control during normal operation and following contingency events?

Dr Sokolowski's issues have some similarities to AEMO, therefore some of the above comments apply.

There are a couple of additional issues highlighted by Dr Sokolowski that are important, as set out below.

The proposal (section 3.2) highlights the imposition of variability on the *remaining* generators that *choose* to provide narrow primary frequency control. This variability includes opportunity and utilisation costs of providing response and some wear and tear costs, Dr Sokolowski completely ignores the former and concentrates on the latter. To do so is to assume all generators have the same marginal cost of generation and will be exposed to the same costs when providing frequency control. CS Energy does not agree with this assumption.

This may misunderstand the nature of competition and the importance of competitive advantage, where a player can outperform its rivals in term of price and quality. In the NEM this would represent the generator with the lowest capacity and energy costs providing more frequency control services than others. To issue a mandate that distorts this process increases costs for consumers.

If we ignore opportunity and utilisation costs altogether this leads to 'magic pudding' propositions, such as getting something for nothing.

The proposal discusses measurement error, notably that AEMO's EMS assumes a system frequency of 50Hz. If frequency deviation is say 0.1Hz then this may be an error of approximately 400MW on the mainland and would lead to this 'feedforward' measure (we explain this in our response to Question 15) contributing to further frequency error.

This is an interesting point but fails to recognise that the EMS could instead include the frequency deviation in its solver. Neither does it account for existing measures (which one should not imply endorsement by being mentioned here) that act in some way to correct frequency, or at least errors in the dispatch process, including Aggregate Dispatch Error and AGC-Regulation constraints/requirements including adjustments for time error.

## 3. Response to Question 3

> QUESTION 3: ISSUES RAISED BY AEMO IN ITS RULE CHANGE REQUEST, *REMOVAL OF DISINCENTIVES TO PRIMARY FREQUENCY RESPONSE*
>
> (a) What are stakeholders views on the issues raised by the AEMO in its rule change request, *Removal of disincentives to primary frequency response*?
>
> (b) Are there any other related issues or disincentives in the NER to the provision of PFR, that the AEMC should consider?

### 3.1. Response to question (a)

The issue in section 3.3.1 relates to Rule 3.15.6A(k)(5)(i), where a "*scheduled participant will not be assessed as contributing to the need for regulating services, and therefore face an allocation for the related costs of regulation services, if the Scheduled Participant achieves its dispatch target at a uniform rate*".

It is suggested that this clause encourages participants to reduce the responsiveness of their plant to avoid being allocated costs through the Causer Pays process.

It has been previously reported that some participants may have reduced primary frequency response of their plant because they were concerned that on the relatively few occasions where the AGC-Regulation Frequency Indicator ('FI') measure and the frequency error (as expressed in MW deficiency or surfeit) opposed each other, a unit providing PFC would be assessed as contributing to regulation services.

Whilst this scenario may have occurred in some instances, (probably less since AEMO's change to the integral component of the FI calculation in Oct-Nov 2018 and not at all since AEMO changed the calculations to remove these occasions from the data set), it is difficult to envisage this as being a strong reason for non-provision of PFC.

The stronger reason is simply that Causer Pays is a cost allocation approach and not a payment mechanism. The payment mechanisms are the AGC-Regulation markets, thus encouraging scheduled participants to focus on earning money through providing Regulation FCAS. Imagine if all providers that can receive positive causer pays factors, did so, this would reduce the need for Regulating FCAS, reducing the incentive to earn a zero causer pays factor: the behaviour is self-defeating.

This isn't to say that a participant wouldn't tune a unit to avoid Causer Pays costs (they may or may not), but they would probably only do so to the extent that they avoid costs, rather than provide services for free in lieu of Regulation providers. It should be more profitable for the participant to provide Regulation Services.

The issue in section 3.3.2 relates to strict compliance with dispatch instructions. CS Energy does not consider this to be a continuing disincentive to PFC.

The issue raised under section 3.3.3, relating to performance stipulated in the Generator Performance Standards, appears valid, in that the plain English reading of the clause S5.2.5.11(i) is confusing and does not reflect current practice of many generators. For example, units at Callide B and Gladstone operate with a symmetrical dead-band of +/-0.1Hz and do not limit their response to occasions when enabled and not by the enabled amount. An ambiguous Rule that implies these plants should limit the response is unhelpful. It is also unhelpful that it doesn't reflect the intent of the Rule as explained by the Commission when it determined to make the Rule.

### 3.2. Response to question (b)

As discussed in response to question 1, the primary issue is simply that it costs generators to provide governor control and given the Rules don’t allow them to be paid for it, they don’t.

If the AEMC changes the Rules to pay for PFC it will be provided by those producers that can do so most cheaply.

PROPOSED SOLUTIONS

## 4. Response to Question 4

> **QUESTION 4: CAPABILITY OF GENERATION PLANT AND THE IMPLEMENTATION PROCESS FOR AEMO'S PROPOSED MANDATORY PFR REQUIREMENT**
>
> In relation to AEMO's rule change request, *Mandatory primary frequency response*, and the draft PFRR:
>
> - For stakeholders who own and operate scheduled or semi-scheduled generation plant: How easily can your plant meet the requirements of AEMO's draft PFRR? What, if any, adjustments or investments would need to be made and what are the expected costs?
> - Do stakeholder agree with AEMO's proposed allocation of requirements between the NER and the PFRR under its proposed rule?
> - Do stakeholders consider the implementation time frames suggested by AEMO in its draft PFRR to be appropriate? In relation to AEMO proposed self assessment process, is it appropriate for generators >200MW to provide AEMO with a self assessment within 60 business days and generators <200MW to provide AEMO with a self assessment within 120 business days?
> - Do stakeholders consider there to be a more appropriate approach to coordinating the implementation of a PFR requirement across the generation fleet?

Section 4.4.1 (technical aspects) of the consultation paper appears to explain the Rule has been drafted from first identifying the generator performance standard capability and second by drawing upon this capability in the Primary Frequency Response Requirement ('PFRR') document. This may have led AEMO to specify a higher operational performance from the machines than can be expected.

In particular:

- with regards to the speed of response, where AEMO thinks 5% change in 10 seconds is slow, many units will not respond so fast, as would be readily demonstrated by the governor models; and
- steam turbines with re-heater lags of 10 to 15 seconds will take 30 to 45 seconds to stabilise from a 5% step in demand from a 0.125 Hz movement outside the dead-band. Larger changes obviously reach 5% faster, but PFR is not comparable to large fast partial load rejection response, which is achieved with the assistance of IP turbine governor valves which remove the re-heater lag, but IP governor valves are not included in the governor models. This needs to be discussed with AEMO in more detail.

AEMO's requirement to sustain the response would require significantly improved dynamic response for the most efficient generators within CS Energy's' portfolio. For other coal-fired power stations that do not have high speed attrition mills, coal fired boiler responses with mill grinding delays of well over a minute could not sustain 5% changes in 10 seconds. Even with the current slower turbine response of around 60 seconds, maximum use of changes in stored steam pressure energy and mill coal inventory storage are required to sustain the 5% change in steam flow and recover steam pressure. Beyond marginal improvements that could be possible through re-tuning, faster response would require a significant project to study options such as mill modifications to provide variable classifier vane control. This highlights the issue that the AEMO proposal is not simply a tightening of the governor, but due to the requirements of speed of response and sustaining the response, is more akin to complete overhaul of the control philosophy. This is likely to be less of an issue for existing FCAS market registered generators.

The idea that this Rule applies equally to all plant misses the point that different generating units have different opportunity costs, capabilities and operating regimes. It cannot be said that the Rule will apply equally to a wind farm, solar farm or coal-fired power station, just because the obligation is the same, because the effects are completely different.

## 5. Response to Questions 5 and 6

> **QUESTION 5: AEMO'S EXPECTED COSTS AND BENEFITS FOR ITS PROPOSED RULE, *MANDATORY PRIMARY FREQUENCY RESPONSE***
>
> In relation to AEMO's proposed rule, *Mandatory Primary frequency response* :
>
> - Do stakeholders agree with AEMO's characterisation of the costs and benefits associated with its proposed rule?
> - What do stakeholders consider to be the immediate and ongoing costs of providing PFR and being compliant with the proposed rules?
> - Is AEMO's proposed compensation arrangements for plant upgrades necessary and appropriate?
> - Do stakeholders consider the proposed rules to be a cost effective solution to the frequency control issues identified by the proponents?

> **QUESTION 6: DR SOKOLOWSKI'S EXPECTED COSTS AND BENEFITS FOR HIS PROPOSED RULE, *PRIMARY FREQUENCY RESPONSE REQUIREMENTS***
>
> In relation to Dr Sokolowski's proposed rule, *Primary frequency response requirement*:
>
> - Do stakeholders agree with Dr Sokolowski's characterisation of the costs and benefits associated with his proposed rule?
> - What do stakeholders consider to be the immediate and ongoing costs of providing PFR and being compliant with the proposed rules?
> - Do stakeholders consider the proposed rules to be a cost-effective solution to the frequency control issues identified by the proponent?

### 5.1. Costs and benefits of the proposed Rules to mandate PFC

AEMO and Dr Sokolowski's mandatory Rule proposals are only partial solutions. Simply mandating PFC be provided by all plant does not ensure frequency is controlled, unless adequate capacity to increase or reduce generation/load is preserved.

Whilst this means the proposals do not impose unnecessary opportunity costs (of capacity) on the cheapest generators, it reduces the effectiveness of the mandate to control frequency. This confuses matters because some of the claimed benefits will not accrue, yet also this will avoid some of the costs.

In any case, AEMO and Dr Sokolowski fail to account for opportunity (capacity) and utilisation (energy) costs. As a result, sections 4.4.1 and 4.4.2, which explain the proponents' cost benefit claims, miss the most significant costs of the proposal. The effect of the 'partial' mandate is to only imposes energy costs and <u>not</u> capacity costs on participants. A mandate simply makes suppliers pay for the service, yet in this case it only imposes the utilisation costs, not the capacity costs for headroom and footroom. Therefore AEMO's & Dr Sokolowski's proposed partial mandates 'underpay' and will not provide the desired narrow band PFC.

To understand the effect of the proposal it is best first to consider a full mandate, which would require each generator to preserve capacity (headroom and foot room) and incur opportunity costs. Implementing a 'full' mandate for all generators to provide PFC, including capacity, would have the following effects:

- removes the reduction in costs from suppliers of frequency control services through competitive advantage (because even the cheapest generator must provide some PFC over generating cheap electricity, increasing overall costs); and
- encourages those elements of the system that demand frequency services not to moderate their demand through the discipline of paying for it. As they are not facing the cost when they consume these services, then they are likely to be encouraged to consume more.

The Rule is likely to impose costs because it will artificially represent the cost of providing PFC as low, increasing the supply and demand of PFC above 'efficient' levels. This is the effect of a technical regulation or mandate for a service where an alternative market arrangement is possible. This would be more obvious should the mandatory proposals be a complete solution and require each plant to maintain capacity to increase to or reduce generation.

The 'partial' mandate confuses matters as this largely depends on the prevalence of opportunity or capacity costs. If there are significant capacity costs, then the partial mandate simply won't work very well, leading to both the benefits reducing as well as the costs.

Given these effects were unaccounted for by the proponents, CS Energy does not believe that the Rule will increase the efficiency of power system operation and planning with minimal to no costs to consumers.

## 6. Response to Question 7

QUESTION 7: AEMO'S PROPOSED RULE, *REMOVAL OF DISINCENTIVES TO PRIMARY FREQUENCY RESPONSE*

**Allocation of regulation service costs — causer pays**

- Does AEMO's proposed rule adequately address stakeholder concerns in relation to the risks and rewards associated with the voluntary provision of PFR?
- Do stakeholders envisage any unintended consequences as a result of the proposed rule change?
- Does the causer pays procedure contain any other potential barriers to the provision of PFR under normal operating conditions?

**Frequency response and compliance with dispatch instructions**

- What are stakeholders views on AEMO's proposed changes to clauses 4.9.4 and 4.9.8 of the NER to address disincentives to PFR relating to compliance with dispatch instructions?

**Operating in a frequency response mode**

- What are stakeholders views on AEMO's proposed rule to address disincentives to PFR related to the requirements for FCAS provision?
- Do stakeholders identify there to be any other sections of the NER that may restrict generators from operating in a frequency responsive mode and providing PFR

### 6.1. Allocation of regulation service costs – causer pays

With regards to the first question, CS Energy does not consider AEMO's proposed Rule addresses concerns with the risk and rewards associated with voluntary PFC.

As previously explained:

- the primary issue is simply that it costs generators to provide governor control and given the Rules don't allow them to be paid for it, they don't; and
- Causer Pays is a cost allocation approach and not a payment mechanism.

AEMO's zero causer pays proposal does not resolve these disincentives.

AEMO has proposed that a unit be awarded a zero causer pays factor avoiding expenses for Regulation FCAS should the unit operate with a narrow range governor control. Therefore, the rewards from providing PFC under AEMO's proposal relate to the participant's consumption or demand of Regulating FCAS services.

Currently a generator *may* be incentivised to tune a unit to avoid Causer Pays costs, but only if this were cheaper than paying for Regulation Services. If they were to tune the unit, they would only do so to the extent that they avoid costs, and not to the extent that they provide services for free in lieu of Regulation providers. This is because it would be more profitable for the participant to provide secondary control AGC-Regulation FCAS services, rather than avoid the cost of them.

### 6.2. Supporting data

The following pages presents some data from AEMO's Causer Pays database, as amended by PD View in their "FCAS-Pays" service. There are three charts presenting data from a coal-fired power station unit and a solar farm.

The first presents the 4-sec data of coal unit, normalised around the NEMDE target (TotalCleared).

Under the Causer Pays method all measurements are made from the 'flat' target to target '0' of the LHS vertical axis. The basepoint – NEMDE target is the expected actual movement of the unit from where it starts the 5 minutes, this respects ramp rates and AGC-Regulation enablement amounts. The green area is the actual SCADA measurements of generation.

The NEM north frequency deviation is presented on the RHS vertical axis, with high frequency blue and low frequency in red.

In most instances the coal unit's deviations from the target-target trajectory is favourable; that it is helping restore frequency to 50Hz. It should be remembered that the coal unit is generating to a flat, target-target trajectory during this 6-hour period and the deviations are very minor, less than 1% of dispatch.

The coal unit operates with limited response (equivalent gain to 96% droop, noting that gain is the inverse of droop) of up to +/- 1.25MW that applies inside the Normal Operating Frequency Band ('NOFB') +/-0.15Hz with a 28sec lag (due to the assumption of Frequency Indicator ('FI') having this lag when the setting was made). This is the type of response implemented to avoid paying for Regulating FCAS and is deliberately limited because the Causer Pays incentive does not encourage the provision of frequency control services.

By comparison 5% droop on the coal unit, is 24MW for a frequency deviation of 0.15Hz (0.3%).

Not all coal units operate with limited droop response. CS Energy has not implemented such arrangements for its most efficient generators which have a low fuel cost and high thermal efficiency, which operate with an incentive to maximise output. These units are typically a a consumer of regulating FCAS services.

The market participant of the coal unit usually receives a zero causer pays factor under the existing arrangements. It is self-evident units of this type would be unlikely to volunteer under the AEMO 'disincentives' Rule proposal as in doing so they will provide more services than they need to receive a zero causer pays factor.

We have also presented comparison data for a solar farm . Both the 'normalised' and 'absolute' charts are presented. The MW error to the target-target trajectory is frequently unfavourable and is evidently a greater proportion of available capacity of the unit than was for the coal unit. The error can be exaggerated if the unit moves in the wrong direction to the AEMO forecast trajectory for that unit.

Please note the plant and period have not been chosen as being representative of general performance: no such representation is made. Yet it is a period where there are significant errors from the target-target trajectory that are more than any droop control that AEMO may require under its incentive regime. By comparison AEMO's proposal for 5% droop on the solar farm, assuming availability of 150MW is 9MW for a frequency deviation of 0.15Hz (0.3%).

There has been some discussion (at the AEMO NEM Wholesale Consultative Forum and following on from the scheduling error dispute) as to whether the 5-minute forecasts for semi-scheduled units could be improved (or decentralised for participants to make rather than AEMO). Improvements are certainly worth discussing, and if cost effective improvements in forecasting or unit control can be made, they should. Over time, given the Causer Pays cost allocation, it is likely these plants will improve performance regarding dispatch, especially as their opportunity costs from moderating dispatch diminish as subsidies are withdrawn (or the price of LGCs under the Renewable Energy (Electricity) Act decreases towards zero).

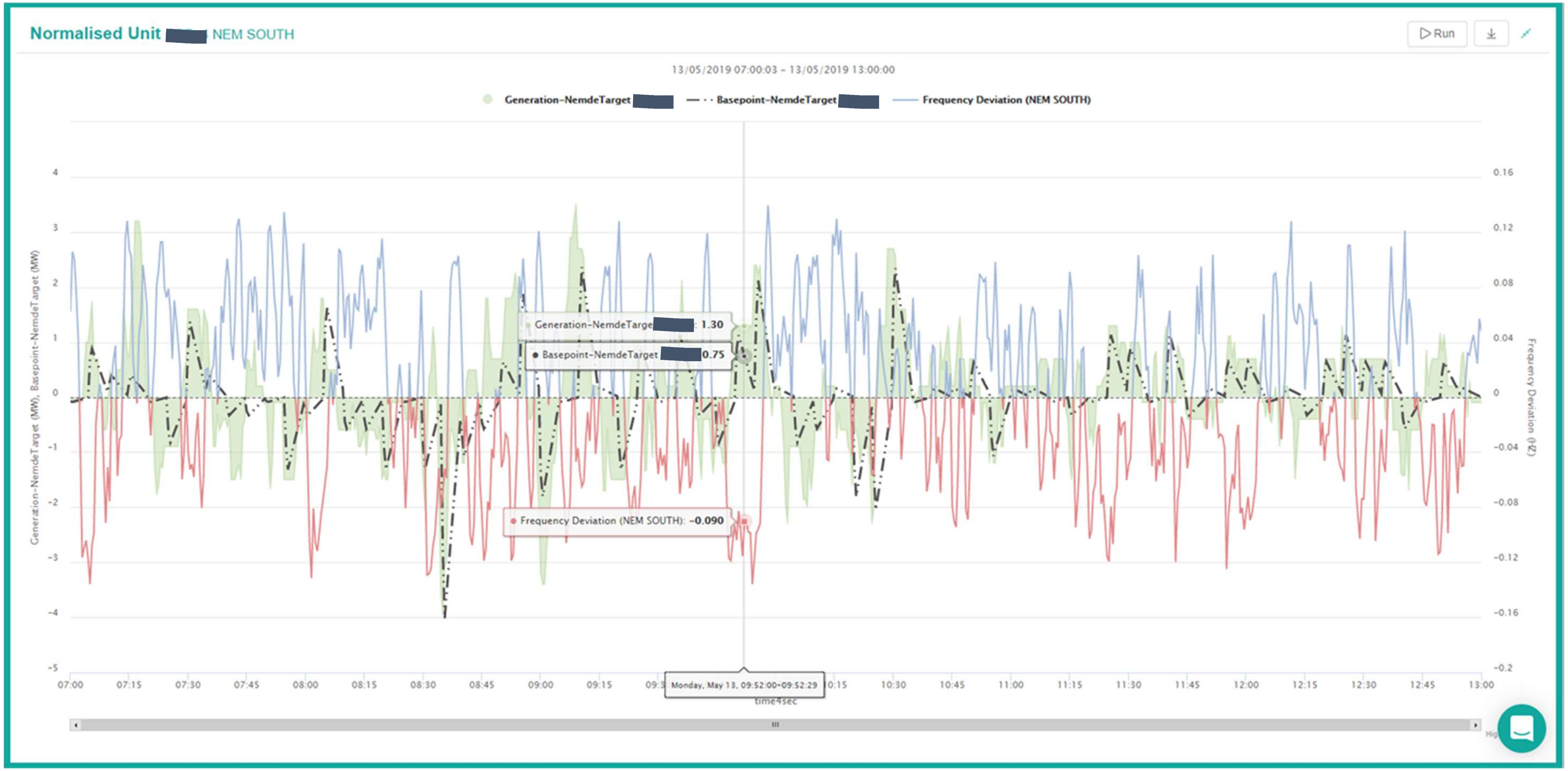
Remembering also that the solar farm is semi-scheduled solar plant, and therefore, (unless limited by a local security constraint), would have little to no headroom available to respond to low frequency.

One would expect the units interested in volunteering to perform this droop function are those whose deviations from the target trajectory as measured under the Causer Pays method (representing their demand for Regulation Services) exceed the amount of narrow range governor 'droop' response AEMO is requesting (representing the supply of frequency control they'll provide). In these circumstances, we suggest a participant would find it cost effective to volunteer under AEMO's 'disincentives' Rule proposal.

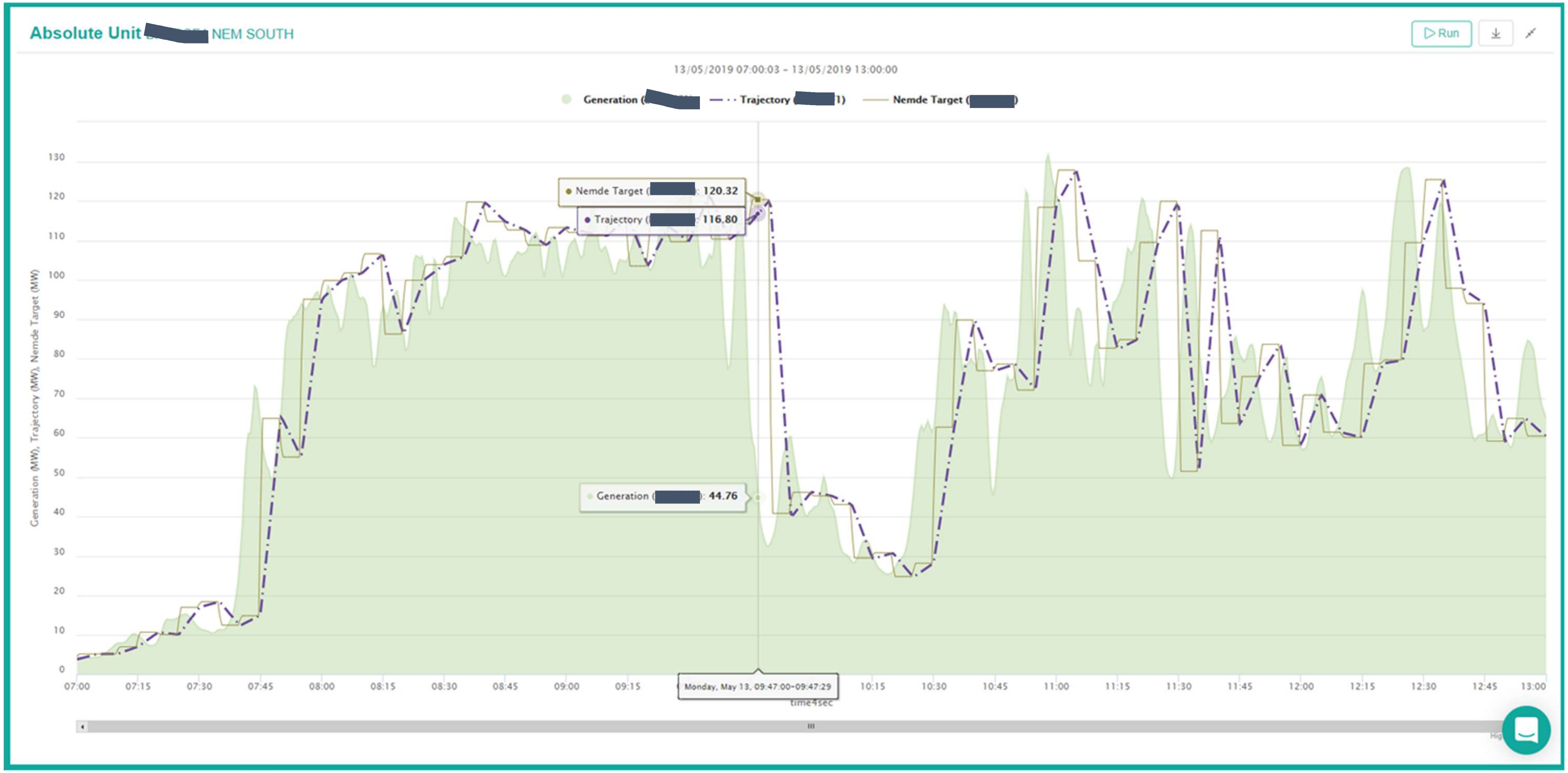
For this reason, CS Energy has concern the proposal will worsen frequency control because some 'consumers' of frequency control services may be allowed to 'dodge' the cost of doing so, simply because they are assumed by AEMO to be providing PFC. Given this, CS Energy is of the view AEMO's zero causer pays proposal should not be implemented under any circumstances.

If the AEMC decides to implement either of AEMO or Dr Sokolowski's proposals to mandate droop response, there is no requirement to grant these units a zero causer pays factor. The Causer Pays factor calculations will assess whether a unit with a droop response remains a consumer of frequency control services.

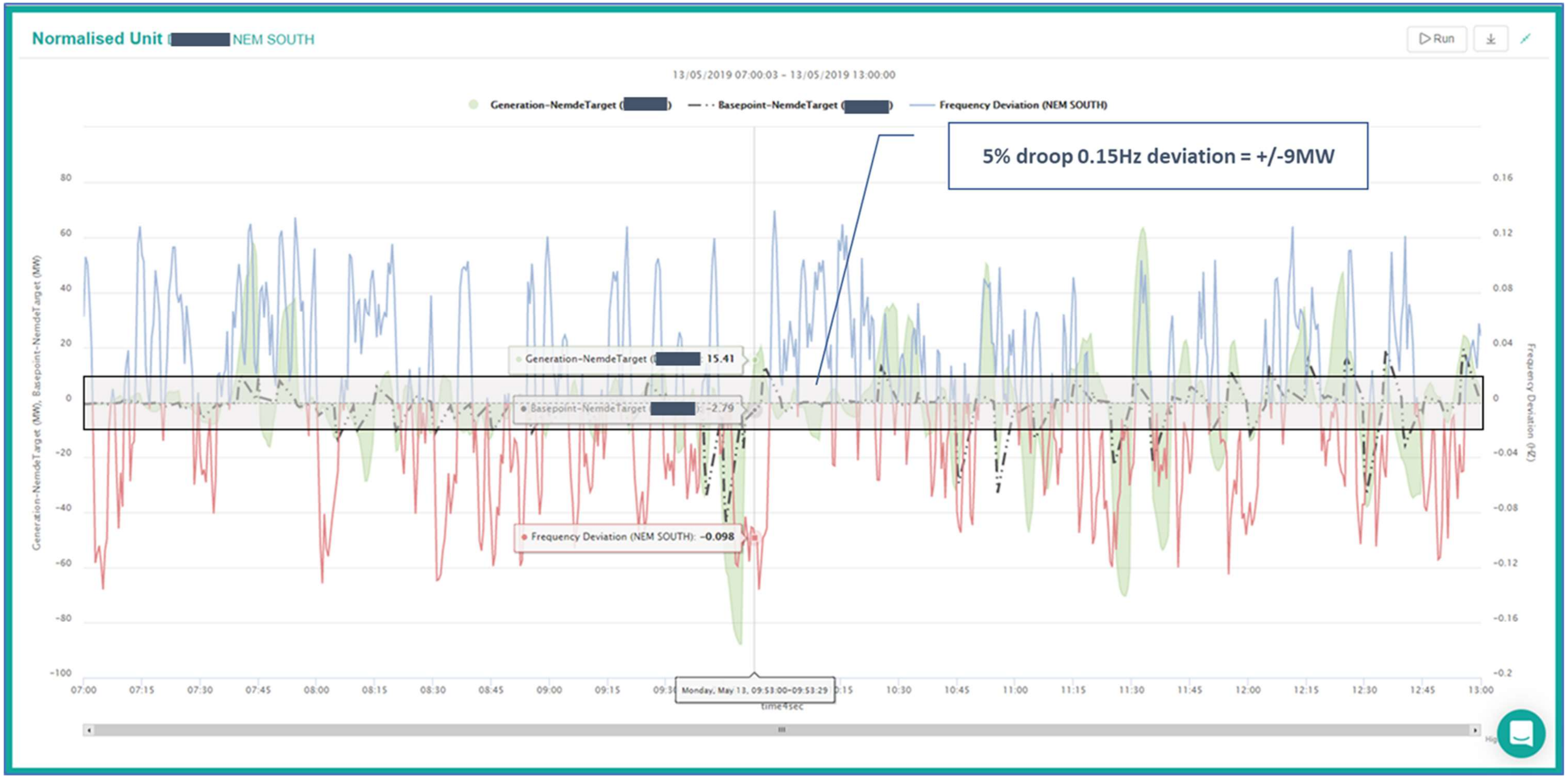
Question 7 figure 1: Coal unit - Normalised around the target to target trajectory:



Dispatch of Solar Farm over 6 hours:



Normalised around the target to target trajectory:



## 7. Response to Question 8

QUESTION 8: AEMO'S EXPECTED COSTS AND BENEFITS ASSOCIATED WITH THE PROPOSED RULE, *REMOVAL OF DISINCENTIVES TO PRIMARY FREQUENCY RESPONSE*

In relation to AEMO's proposed rule, *Removal of disincentives to primary frequency response*:

- What are stakeholders' views on AEMO's estimate of the associated costs and benefits?

The proposal does not resolve disincentives to provide PFC because it does not resolve the core issue, which is that it costs generators to provide governor control and the Rules still won't allow them to be paid for it.

Additionally, Causer Pays is a cost allocation approach and not a payment mechanism. This is the reason Causer Pays does not encourage the provision of large quantities of narrow band PFC under normal operating conditions. If the proposed Rule is implemented on a voluntary basis, only those participants with plant that consume more frequency services than they are expected to provide will volunteer. These volunteers are therefore more likely to consume even more frequency control services than they presently do because they would no longer be exposed to the cost of doing so.

In summary the zero causer pays factor proposal provides no benefits and simply increases costs, which is to be expected for a Rule that reduces the effectiveness of one of the more efficient cost allocation processes, Causer Pays, in the NEM. The marginal cost signals of poor dispatch (consuming frequency services) will be removed.

## 8. Response to Question 9

QUESTION 9: DR SOKOLOWSKI'S PROPOSED CHANGES TO ADDRESS DISINCENTIVES TO THE PROVISION OF PRIMARY FREQUENCY RESPONSE

In relation to Dr Sokolowski's proposed rule, *Primary frequency response requirement*:

- What are stakeholders' views on Dr Sokolowski's proposed changes to the NER to address disincentives to PFR?
- Do stakeholders envisage any unintended consequences as a result of the proposed rule change?

The amendment to clause 3.15.6A(5) may result in a change to the Causer Pays allocation calculations, because it implies a different 'base' trajectory from which to calculate deviations. This may have some unintended consequences given Causer Pays is a cost allocation process for Secondary Control

The proposals for clause 4.9.4(a)(4) and clause S5.2.5.14 are largely administrative additions to dispatch obligations and Generator Performance Standards to reflect the mandated droop response at the core of Dr Sokolowski's proposal. CS Energy does not believe the amendments are necessary provided the clauses are not given their literal meaning and the NER is interpreted as a whole while recognising the dynamic nature of the power system.

## 9. Response to Question 10

> **QUESTION 10: AEMO'S RESPONSIBILITY TO MAINTAIN AND IMPROVE POWER SYSTEM SECURITY**
>
> In relation to Dr Sokolowski's proposed rule, *Primary frequency response requirement*:
>
> - Do stakeholders consider there to be value in amending cl 4.3.1 to explicitly refer to AEMO's responsibility to improve, in addition to maintain, power system security?

AEMO has been conferred an express statutory *function* to "improve" power system security under the National Electricity Law. Under the NER, the *responsibility* to improve power system security is found only in clause 4.1.1 and not clause 4.3.1. We are not aware of the underlying reasoning for drafting the NER in this way (these clauses have been unamended since commencement of the NER). Given this, CS Energy does not consider the value in amending clause 4.3.1 has been demonstrated.

## 10. Response to Question 11:

> **QUESTION 11: INERTIA AND INERTIA SUPPORT ARRANGEMENTS IN THE NER**
>
> In relation to Dr Sokolowski's proposed rule, *Primary frequency response requirement*:
>
> - Is the current chapter 10 definition of Inertia appropriate and fit for purpose?
> - Do the current arrangements for Inertia support activities adequately allow for Inertia support by way of fast frequency response from inverter connected plant?

CS Energy and IES Systems made significant representations to the AEMC on possible improvements to dispatch and pricing, (during the consultation on the System Security Review and 5-minute settlement), including discussion on measuring and pricing inertia. The implication was that frequency control and the inertial contribution could be included in energy prices through adjustments to settlement amounts.

At the time the AEMC concluded the responsibility to maintain minimum inertia levels should be allocated to the network monopolies. CS Energy recollects the AEMC also concluded that inverter connected plant 'synthetic inertia' was not a direct substitute for inertia from synchronous machines: Rules specifying its use were needed. Whilst it may be worth the AEMC reviewing these decisions and the work of IES Systems regarding inertia, this Rule proposal is probably not the appropriate opportunity. These questions are complex and should be considered separately in their own right.

> - How could the arrangements for Inertia and inertia support activities in the NER be improved to better utilise the capabilities of inverter connected plant?

The IES Systems work with CS Energy was considered in the AEMC FCAS Review with the development of the "deviation pricing" proposals. This would be the ideal way of including plant with inertia or "synthetic inertia" in some pay-and-paid-on-performance marginal price incentive.

## ASSESSMENT FRAMEWORK

### 11. Response to Question 12

> **QUESTION 12: ASSESSMENT FRAMEWORK**
>
> In relation to the AEMC's proposed assessment framework for the PFR rule changes:
>
> - Do stakeholders consider that the assessment framework is adequate for considering the PFR rule change requests from AEMO and Dr Sokolowski?
> - Are there any other relevant considerations that should be included in the assessment framework for the PFR rule changes?

In justification for the three-stage assessment priority, the Commission states in section 5.1:

"*when the fundamental system security needs are met, the Commission will seek to investigate further improvements to the frequency control arrangements to increase overall economic efficiency of frequency control in the NEM*"

This is an interesting statement because it suggests a mandatory requirement for PFC could be implemented and then further marginal price (economic) enhancements could be added later.

Even though a mandate distorts the economic incentive and renders it less effective, (by distorting the production and consumption of the service from efficient levels), in this case applying a real time economic incentive, such as deviation pricing, to those plant under the mandate, should ensure those plant that deviate worse than their droop characteristic under the mandate would need to pay. This would at least 'keep plant honest' and ensure there's a payment for compensating response. The compensating response may not come at the lowest cost (as the response would come from a range of plant mandated to supply the service, not the cheapest).

AEMO's proposal, which is a mandate and then withdrawal of an economic incentive (Causer Pays) would be unstable and unlikely in the long run to preserve supply more than consumption, as it does not ensure payment for these services.

The assessment framework should attempt to balance these short and longer-term goals. Give the Commission has concluded that something needs to be done immediately, this probably leads to some transitional arrangements, yet not as proposed by AEMO and Dr Sokolowski. CS Energy would support a compromise arrangement and has some suggestions in this regard, outlined in response to Question 14.

### 12. Response to Question 13

> **QUESTION 13: TECHNICAL REQUIREMENTS OF EFFECTIVE PRIMARY FREQUENCY RESPONSE**
>
> In relation to the discussion of the technical requirements for effective frequency control and the policy options described in section 4.4:
>
> - How do stakeholders view the ability of market or regulatory approaches to provide the necessary broad-based frequency response from participants?
> - What issues are likely to arise with market or regulatory approaches in achieving the objective of a broad-based frequency response?

CS Energy thought this section of the consultation was confusing as to its purpose. On the one hand there is discussion over how (market or mandate) a broad-based response could be achieved, yet the reason for doing so is unclear.

Is the purpose of broad-based response for:

1. 'minor' deviations, which would be frequency control in the NOFB including dealing with undamped frequency oscillations (narrow band response); or
2. 'major' deviations, dealing with rare, extreme non-credible contingencies, that are more complex and less predictable (wide band response)?

The implication is that it is both. Conflating both issues (as presented by AEMO) is unhelpful because the underlying issue for each is different.

The underlying issue that needs to be solved for encouraging narrow band response for 'minor' deviations (as discussed in response to Question 1) is a failure to pay suppliers who could control frequency using PFC under the Rules.

A market for deviations (or similar) would be best placed to provide an incentive for controlling frequency within the NOFB, as this resolves the underlying issue that costs should be paid for, in the most effective manner. It would also be a complete solution as it pays for capacity costs, unlike the proposed mandates which don't include reservation of capacity.

By contrast CS Energy has argued that the same underlying issue doesn't apply for 'major' frequency deviations from rare or extreme, non-credible or multiple contingencies with very high consequence. This is because it is in the interests of generators to respond to these events with wide band response, +/-0.5Hz. Under such events the costs of responding are lower than costs imposed by failing to respond (speed trip, forced cooling, plant damage, start-up costs, possible energy market exposure). This logic should apply to all plant, because those that choose to free ride on other plants' wide range response, do so in the knowledge this increases the likelihood of system failure.

In addition, the opportunity costs presented by different fuel costs of plant are unimportant when such large deviations require most of the generation fleet to respond. The opportunity costs of plant are also trivial compared to the potential costs that could be imposed. As discussed in our response to Question 1, the underlying issue appears to be either free-riding in a shared grid or the discounting of the risks by some participants. This can be solved by regulation without significant distortions from existing behaviour. As noted above, CS Energy already provides wide band response and we would expect other generators to act in this way.

It is for these reasons that CS Energy considers a Rule mandating wide range +/-0.5Hz governor droop response, consistent with the Generator Performance Standards for partial load rejection, should be implemented.



## 13. Response to Question 14

**QUESTION 14: TEMPORAL CONSIDERATIONS**

In relation to the discussion of the temporal requirements for the development and implementation of a solution to deliver effective frequency control:

- How do stakeholders reconcile the need to address system security with the objective of minimising the long-term costs to consumers?
- Do stakeholders consider the need to address system security in a timely manner as influencing the mechanism adopted to address the issue?
- Do stakeholders consider the process of implementing physical changes to generator governor controls as influencing the choice of mechanism?

As previously explained, the conflation of using PFC to control minor deviations and to deal with rare, 'major' deviations, leads to the premise that the only option available is mandating narrow range frequency control, as it appears to deal with both issues. CS Energy has concluded the conflation of these issues is unnecessary and has highlighted that they are fundamentally different underlying problems. Whilst a mandate is appropriate for rare, 'major' deviations, it is not for using PFC to control minor deviations.

The lack of PFC controlling frequency in the NOFB (and dealing with undamped frequency oscillations) arises from the underlying failure to price and pay for this service. If the benchmark is "something is better than nothing", solutions can be put in place rapidly and improved upon over time. The proposition that this can't be done in less than 3-4 years misrepresents the potential for relatively simple pricing approaches to significantly improve performance as opposed the status quo.

The Commission has outlined several possible options regarding the provision of frequency control services, in sections 4.4.1 and 4.4.2. From the drafting in these sections and on page 89, it appears Option B, tighter dead-bands on FCAS providers, Option C - Mandatory PFC the proposal, and Option D – Contracts are all being considered as short-term options to improve frequency control stability and system security.

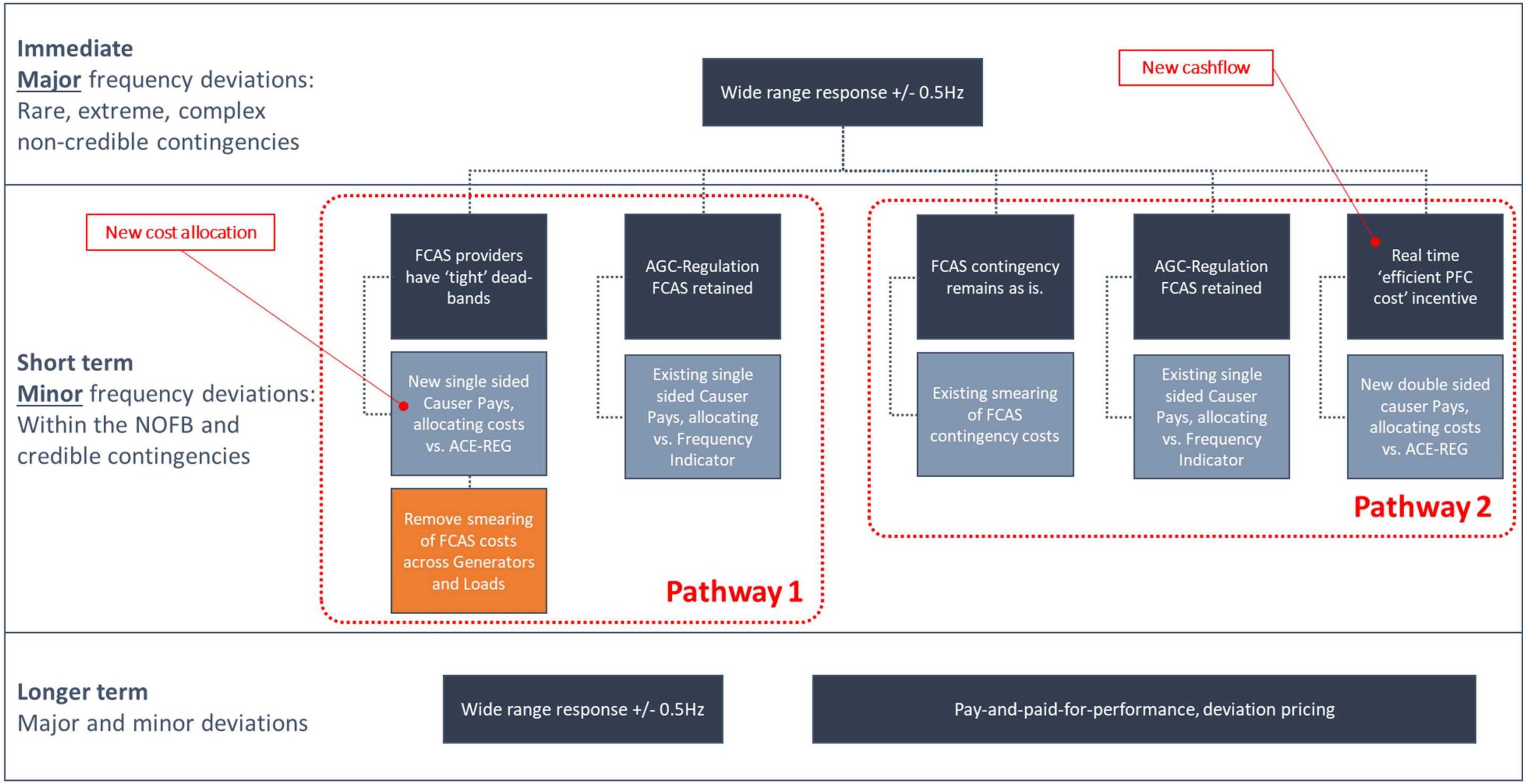
For the reason mandated narrow range response doesn't pay for the cost of providing the service, (and remembering that CS Energy supports the mandating of wide-band response), CS Energy does not consider narrow range mandatory PFC requirement to be appropriate. It would be made considerably worse with the proposed zero causer pays factor. Because mandating response doesn't pay for the cost of providing the service, it also doesn't address the need for headroom (low frequency) and foot-room (high frequency) and is only a partial solution.

Whilst contracts address the underlying problem, by introducing a cash-flow, it is a poor option because it prevents participants easily optimising when and how to provide response and participants will tend to purchase too little or too much response at any one time. For a market that operates in terms of seconds, it is sub-optimal to revert to long term contracts. Even so, a contracting proposal is superior to AEMO's 'partial' mandatory proposal.

The following sections propose three possible 'pathways'. The first two start with immediately implementing a mandatory wide range response obligation and finish with a combination of that obligation and a longer term economic incentive, a "paid-on, pay-on" performance approach, e.g. deviation pricing. The question these pathways address is what to do in the short to medium term to incentivise PFC to control frequency in the NOFB, which requires a payment to recover the costs of providing the service.

The third pathway also assumes the end goal is an efficient economic incentive yet starts with the premise that the narrow band droop response mandated as per AEMO's proposal needs a financial incentive or compensation mechanism to ensure it works properly.

14. Possible pathways 1 and 2 for improving frequency control:



### 14.1. Pathway 1 – tight dead band contingency FCAS and revised cost allocation

Pathway 1 is similar to AEMO's Option B – tighter dead-bands on FCAS providers but recognises that if contingency FCAS is managing smaller deviations in frequency it would be appropriate to improve the cost allocation of this method through a mimic of the existing Causer Pays approach.

Instead of the costs being allocated on measured performance on the secondary control signal, under Pathway 1 costs would be allocated on measured performance against a primary frequency control requirement – the Area Control Error – Regulation (ACE-Reg).

This proposal addresses the underlying problem by increasing the cash-flows available to providers by:

1. removing the smearing of costs; and
2. through changes in price of the FCAS 'contingency' markets.

Noting the FCAS contingency markets, would no longer be for contingency.

The main drawback with this proposal is how to integrate switching loads. Switching loads are not providers of PFC. In recent years the proportion of low frequency, contingency response that provides switched response at a set frequency trigger level has increased. Some has been a function of the unbundling ancillary services Rule change and because of a reduction in available headroom of synchronous, thermal plant since the closure of Hazelwood and Northern.

### 14.2. Pathway 2 – additional financial incentive, double sided causer pays

Pathway 2 recognises the flaw with the AEMC's Option F 'two-sided' Causer Pays.

The flaw with two-sided Causer Pays is even if positive factors were paid for under Causer Pays (rather than limited to 0), providers of frequency control services are encouraged instead to provide services through Regulation FCAS, not through Causer Pays. This is because to do otherwise, (rely on being paid for their positive factor), they will reduce the need for Regulation Services which reduces the transfers of cash payments through the Causer Pays mechanism: positive performance is self-defeating.

The way to encourage positive performance for PFC under Causer Pays is to create a separate, new 'two-sided' Causer Pays that allocates an additional cashflow for PFC. Allocating additional cash is the best solution because it deals with the underlying problem directly: that it costs money to provide PFC which needs to be paid for.

Please note that this new cash-flow may compete with AGC-Regulation FCAS, in that providers may response to the new incentive and reduce the need for Regulation FCAS. By pricing primary frequency control, it is likely there will be change in overall cashflows between those providers of primary and secondary control.

The new cashflow if termed a real-time 'efficient cost estimate' and is calculated using current dispatch prices which are used to estimate capacity (opportunity) and utilisation (energy) costs for a likely power plant providing primary frequency control.

The frequency error is converted into 'ACE-Reg', which is an estimate of the demand for PFC. Over the five minutes the demand for low frequency PFC and high frequency PFC is calculated and multiplied by the capacity and utilisation prices to provide an estimate of the cost of low and high frequency PFC.

Ideally this cost would be allocated under a new double-sided causer pays calculation using each elements contribution to the need for ACE-REG.

This Efficient Cost estimate has been prototyped by CS Energy and Intelligent Energy Systems (IES) and is explained further below.

The Efficient Cost estimate assumes reserves for frequency response should migrate to the region with the greatest abundance. The RRP chosen is the Region that has the greatest reserves of 'scheduled' generators (therefore excluding non-scheduled and semi-scheduled generators such as wind farms and solar fields).

This RRP is used calculate the opportunity costs, capacity price and utilisation price, as described in response to Question 1 above. These prices need to be multiplied by volumes to provide a cost estimate for each 5-minute dispatch interval.

### (a) Calculating capacity and utilisation volumes

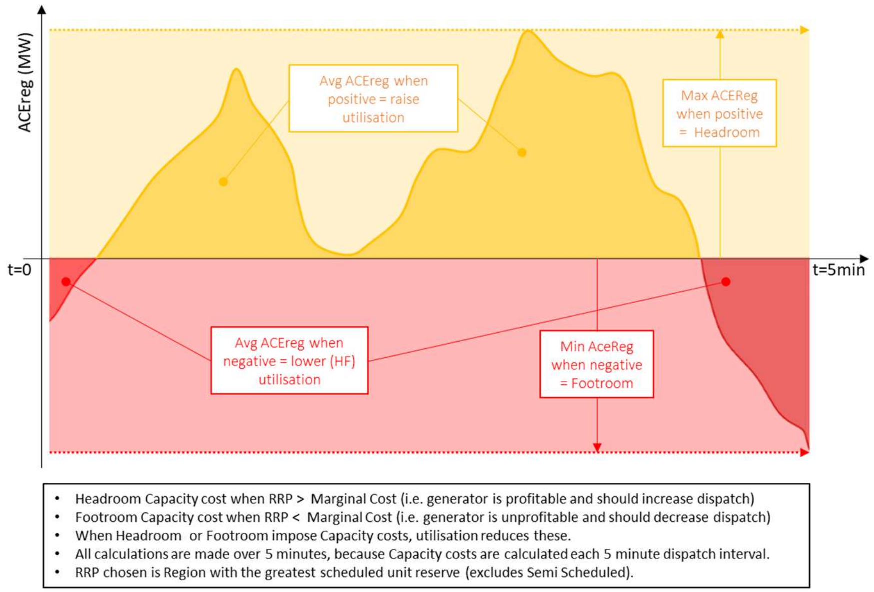
Capacity and utilisation volumes are calculated from the frequency error, in MW, known as the Area Control Error – Reg (ACEreg). Using 4-sec frequency data IES Systems have calculated the 'problem', which the frequency error equated to a 'MW' value, known as the Area Control Error (ACE).

The ACE is reversed to provide ACEreg and subject to gain calculations, indicating an amount of 'dispatch' to return to 50Hz. This can be calculated with an adjustment for Time Error. ACEreg calculation can be calculated in different ways depending on the desired response.

Low and high frequency costs have been kept separate as they impose significantly different costs.

Please note the average and maximum calculations are performed over the 5-minute dispatch period.

The following schematic presents the concept:

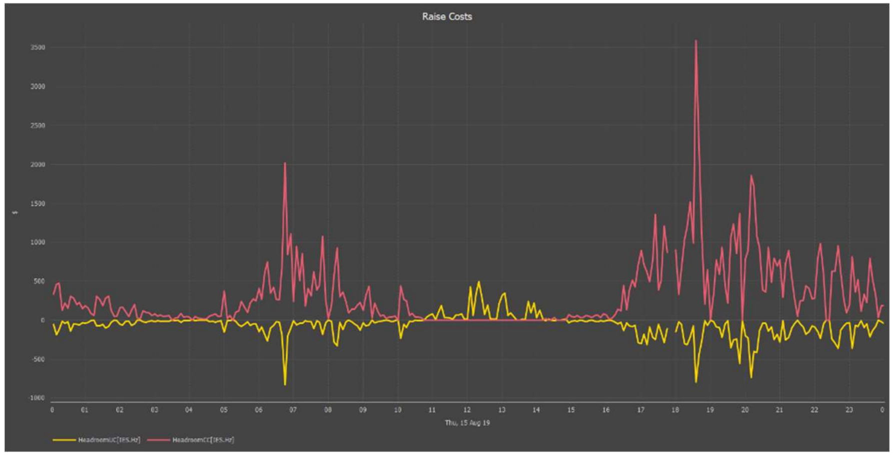



### (b) Calculating capacity and utilisation costs to provide efficient cost estimate

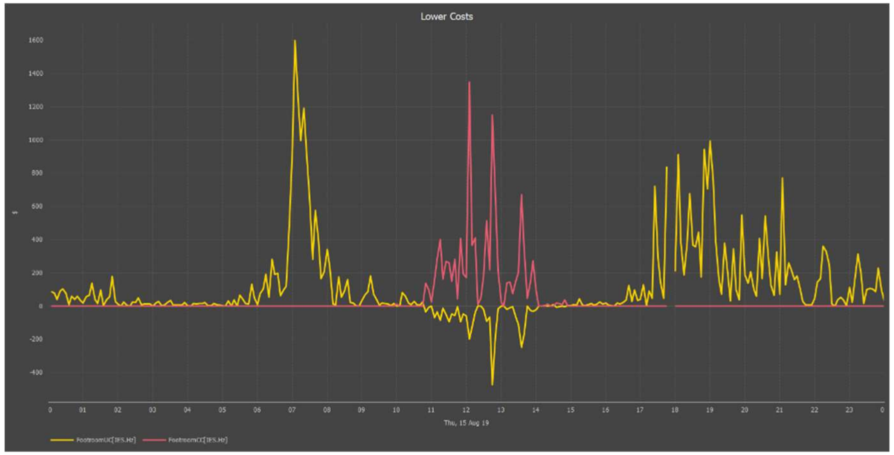
Now that Max(ACEreg), Average(positiveACEreg), Min(ACEreg), Average(negativeACEreg), have been calculated these can be multiplied by the appropriate Capacity Price and Utilisation Price to give separate Capacity Costs and Utilisation Costs for both lower and raise services.

- Raise Capacity Cost = Max(ACEreg) * Headroom Capacity Price
- Raise Utilisation Cost = Average(positiveACEreg) * Headroom Utilisation Price
- Lower Capacity Cost = Min(ACEreg) * Footroom Capacity Price
- Lower Utilisation Cost = Average(negativeACEreg) * Footroom Utilisation Price

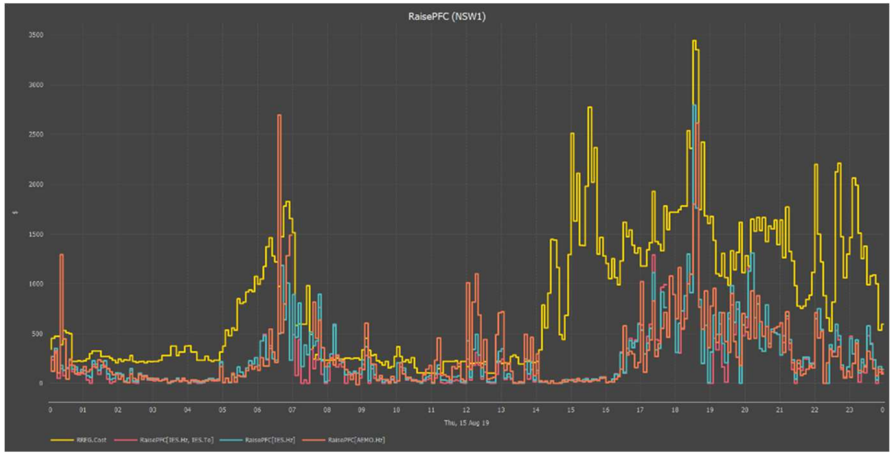
The following charts present the results:



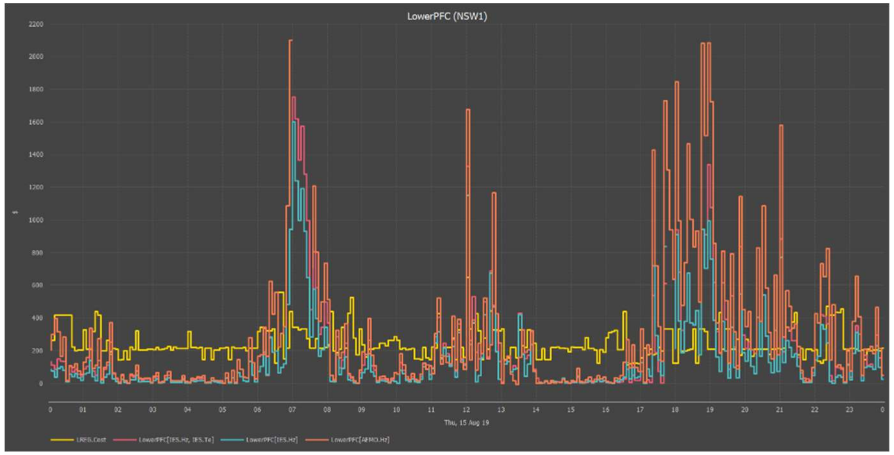

Given the use of max/min for Capacity Costs, where these are positive the Utilisation Cost, based off an average, is always less than the Capacity Cost.




The Capacity and Utilisation Costs are then added together to provide the 'Efficient Cost' estimate, titled "RaisePFC" and "LowerPFC". They are shown in comparison to the cost of purchasing Regulation Services from Mainland providers. Multiple calculations are shown for RaisePFC, due to three variants of ACEreg. These variants are discussed in a later section of this document.




In each case the reference to 'NSW1' is that the regulation price from that region is used to calculate regulation FCAS costs (this was the simplest way of calculating the costs and is usually true, because the Regulation price for enablement across the Mainland is usually being the same for all Mainland regions.



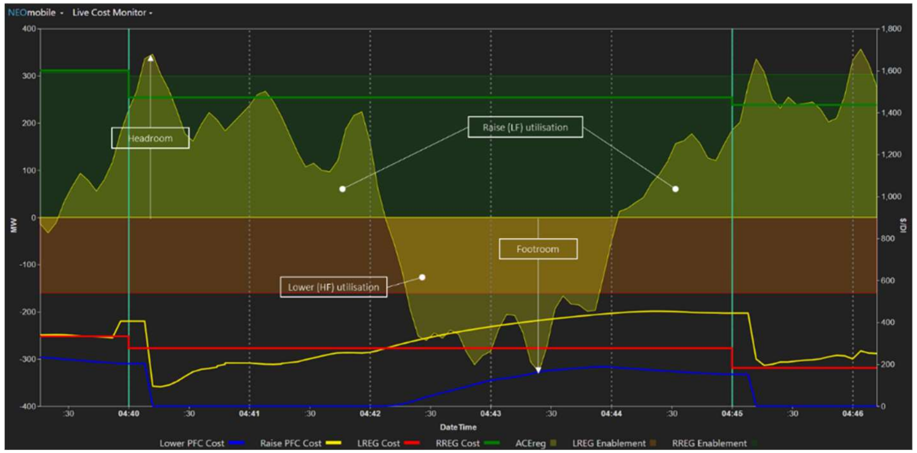
A direct comparison should not be made, because CS Energy considers Regulation and Primary Frequency Control (governor control) are not direct substitutes and that there should be a balance between primary and secondary frequency control services.

Nevertheless, it is frequently the case that the 'efficient cost' of the two services is significantly different to the cost of Regulation FCAS. This was expected.

### (c) Calculating the 'efficient cost' estimate 'live'

Power system frequency varies continuously, leading to the question whether a real time or 'live' estimate of the efficient cost over the 5 minutes could be calculated to encourage participants to respond in real time.

The following chart presents the real time monitor, although it a disservice given the monitor is not static, but 'snakes' through the 5-minute period as the max(ACE) and average(ACE) values change. A present the monitor uses either a trailing average of 5 minutes but can be amended to start calculating from the dispatch interval boundary. The latter calculation is used below because it is easier to understand the underlying calculation by doing so.




The monitor extends to 7 minutes and has the following elements:

- ACEreg – yellowy green area (LHS, 4 sec data)
- RaisePFC 'efficient cost' estimate ($RHS, 4 sec data)
- LowerPFC 'efficient cost' estimate ($RHS, 4 sec data)
- RaiseReg enabled: green transparent area (LHS, 5min data)
- LowerReg enabled: red/brown transparent area (LHS, 5min data)
- RaiseReg costs: green line ($RHS, 5min data)
- LowerReg costs: red line ($RHS, 5min data)

The delays at the start of the dispatch interval are the result of 5-minute dispatch interval price data updating in IES Systems' database

### (d) Summary – pathway 2

The 'efficient cost estimate' represents a very rough estimate of the prevailing cost of providing primary frequency control. Allocating this cost through a two-sided causer pays mechanism in conjunction with the existing Regulating FCAS Causer Pays approach should "fill the gap" where PFC isn't priced under the Rules.

Implementing the efficient cost estimate cash-flow should increase the incentive to provide PFC under normal operation and, unlike the proposals of AEMO and Dr Sokolowski, also attempts to incentivise the provision of capacity or headroom to provide that response.

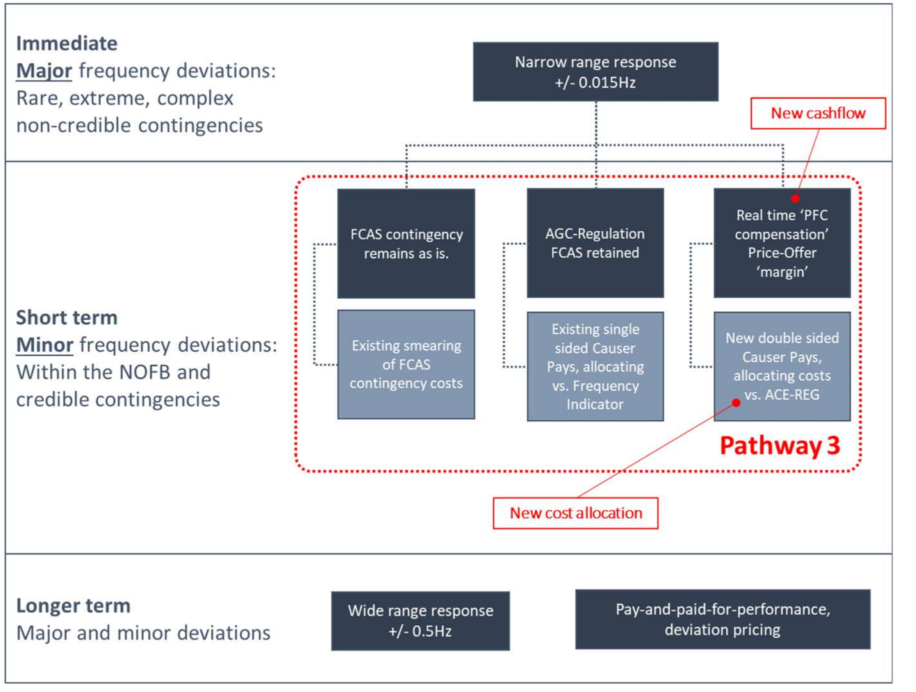
## 15. Pathway 3 – partial mandate, double-sided causer pays compensation regime

Pathway 3 recognises the likelihood that the AEMC will, possibly temporarily at least, change the Rules to mandate narrow band response. Rather than implement AEMO's 'zero' causer pays 'relief' proposal in conjunction with the mandate, this pathway recommends implementing a compensation mechanism for those plant providing droop control services. Given the AEMC appears minded to implement a mandatory requirement, at least in the short term, this pathway appears a pragmatic solution.

Like Pathway 2, it aims to allocate a cost between participants through a double-sided causer pays mechanism. Unlike pathway 2, which devises a cashflow to 'hopefully' solicit a response from the most efficient providers, this approach aims to compensate the providers mandated to provide the service at their cost. This cost should be higher than the Efficient Cost estimate (because plant where it is costlier to provide frequency control, than others, are mandated to do it).

On a per unit basis, the cost of frequency control can be measured as capacity cost and utilisation cost, in a similar manner to the efficient cost estimate. The only difference being these costs are calculated using the 'spread' or 'margin' between the unit's offer price and the Regional Reference Price for energy. For example, should the offer price be $35/MWh and the RRP be $50/MWh, then the spread in that 5 minutes is $15/MWh. This calculation will be performed on a unit by unit basis, given each unit has a different offer price and RRP combination.

Using the 4-second SCADA data presently used for Causer Pays purposes, AEMO could calculate the droop response provided by the unit and use this to calculate the capacity costs and utilisation costs, performing low and high frequency services separately (as they have different cost characteristics). The volume will be priced at the offer-price margin and the unit is compensated for providing PFC response. Those participants measured to be causing a need for other mandated units to respond are then allocated the costs.




The disadvantage of this approach (as opposed to Pathway 2) is that it is a compensation regime for providers mandated to provide the service. Therefore, it

has the problems associated with a mandate, in that this will increase the overall cost of provision, especially when costs are a function of utilisation (rather than capacity). The advantage of this approach is that those providers that don't want to provide response can avoid doing so by not providing headroom and foot room (capacity), and those that want to provide the response, safe in the knowledge they will be compensated for it, can deliberately provide (capacity). One would expect those unit preserving capacity would provide most service.

Another advantage is that it allocates costs on system participants that are causing a need for PFC (such as unit deviating, failing to start, tripping, losing steam, loss of wind, milling problems, losing sunlight), rather than simply imposing the costs on the providers of primary frequency response. This payment should moderate poor behaviour somewhat.

## 16. Response to Question 15

> QUESTION 15: CONSIDERING THE COST BENEFIT TRADE-OFF FOR THE PROVISION OF PFR
>
> In assessing the proposed rules for mandatory PFR, the Commission seeks stakeholder input on the following questions:
>
> - What is the existing capability of the generation fleet to provide narrow band PFR?
> - What is the scale and cost of plant upgrades that would be required to meet different PFR performance requirements, including the performance specifications set out in AEMO's draft PFRR?
> - How much of the fleet must provide narrow band PFR in order to be confident that the immediate system security needs are satisfied?

Question 15 requests stakeholder input on the cost and capability of providing narrow band response from the existing fleet.

With regards to *cost*, whilst all CS Energy plant can provide narrow band response, the reason only some do is because provision of such response is more expensive for some than others. This was explained in response to Question 1, where opportunity (capacity) and utilisation (energy) costs vary by plant.

With regards to *capability*, CS Energy is concerned by the requirements in the PFRR, with these outlined in our response to Question 4.

CS Energy would argue the immediate system security needs can be satisfied by implementing wide-range response. Given this, the third question can then be 'reframed', based on what would be an effective control system for the NEM.

The power system has both feed-forward and feedback controls, with

- feed forward controls are things such as AGC dispatch targets, ramping etc., unit commitment; and
- feedback controls are things such as:
    - proportional response - in proportion to changes in the error, aims to stabilise or contain error;
    - integral response – in proportion to the integral of the error, aims to correct error to the feed forward control; and
    - derivative response – when there are delays/lags aims to compensate for these by increasing response in proportion to the rate of change of error

An effective control system should have a mix of these responses, especially given the response at a unit level (for each of the above) may not be identical – i.e. slower proportional response may cause oscillations with faster proportional response (you need some integral response or switched response to move from this state).

The AEMO consultant's report highlighting the importance of proportional primary control is welcome because it highlights a service a generator could be paid for. It is also helpful because it discusses the relationship between primary proportional control and integral and derivative secondary control similarly to described above.

Yet, rather than every unit provide narrow range control without express reservation of capacity for response, CS Energy would instead argue that only several generators provide this duty, being chosen to do it, with the lowest cost resulting in the lowest price.

It is unnecessary for all units to be performing the duty and may be undesirable as it may lead to excessive proportional control at mixed speeds, leading to proportional oscillations, especially with delayed response from Hydro plant (which could make up a significant proportion of dispatch under future conditions).

Hydro units also generally have wider response ranges, hence to fully utilise that range with a 5% droop before any UFLS of OFGS operates, hydro units would ideally choose to have narrower dead-bands than thermal plant, which would also help overcome their initial inverse response before other types of generators kick in, and thus reduce the risk of interactions.