3/4/2023

Ms Anna Collyer
Australian Energy Market Commission
PO Box A2449
Sydney South, NSW 1235

Dear Ms Collyer

Efficiency Improvements in Central Dispatch Related to Contingency Frequency Control Ancillary Services (FCAS)

This rule change request proposes requiring central dispatch to reduce the size of the largest contingency or contingencies when there are market benefits and no negative impact to system security. This increased efficiency will put downward pressure on the costs of contingency FCAS services imposed on the system.

This is rule change 2 of 2 in the "Efficient Procurement of FCAS" suite of changes. Rule change 1 of 2 called *Efficiency Improvements in Contingency Frequency Control Ancillary Services (FCAS) Cost Allocation* proposes improving the efficiency of how FCAS costs are allocated through using a modified version of "runway pricing".

These rule changes propose mechanisms that work synergistically to efficiently lower the cost of contingency reserves. Additionally, as the FCAS cost allocation rule change (rule change 1) reallocates more risk on to large generators and loads there is a greater need to examine managing the size of our largest contingencies through central dispatch. This is explored further in this rule change in *Section 4: Interaction with Efficiency Improvements in Contingency FCAS Cost Allocation Rule Change*.

Electricity prices are increasing, creating a drag on the overall economy and dramatically impacting individual energy users. I hope that by more efficiently procuring our contingency FCAS services this flows through to put downward pressure on energy users' bills.

Thank you for considering this request. I can be contacted at mitch@grids.dev

Yours sincerely,

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1 Why Do We Have Contingency FCAS Markets?

Sometimes in the NEM things suddenly turn off with absolutely no warning. This could be a generator, a load, or even an interconnector. If the generation or load source turning off is large enough it can cause an energy imbalance that jeopardises system security. To correct for this imbalance, we have reserves continuously on standby that can replace enough of the lost load of generation source for up to 10 minutes to get us to the end of the next dispatch period.

Every 5 minutes AEMO calculates how much capacity is required to be on standby just in case the biggest generation or load source trips (including network elements) and AEMO procures that capacity from the market. This capacity is also very useful for when smaller generation or load sources trip, but the total amount procured is dependent on the largest one.

The cost of these reserves is borne by the market.

2 The Problem

Under the current arrangements, AEMO does not operate central dispatch with an aim optimise the size of the largest contingency against the costs of procuring ancillary services to manage the associated contingency risk.

Imagine a simplified situation where central dispatch must procure 500MW of capacity for wholesale energy dispatch, and it can procure contingency FCAS capacity against its largest contingency at a flat rate of $30/MWh.

In the next 5-minute dispatch period there’s one 500MW generator that bids its full capacity into wholesale at $14/MWh, and five 100MW generators that bid in their full capacity at $15/MWh. None of these generators are bidding any capacity into FCAS.

Which generators should we dispatch into wholesale? Keen readers may say “the five generators at 100MW each” as even though the wholesale costs are slightly higher by dispatching them over the single 500MW plant, the contingency FCAS costs are five times lower, leading to a lower total cost between wholesale and FCAS ($875). This is correct yet the NEM dispatch engine (NEMDE) would have dispatched the 500MW generator, incurring over twice the amount in total costs ($1833.3).

	Current NEMDE solution	Lowest cost solution
Wholesale Costs	$ 583.3 (41.7MWh@$14/MWh)	$ 625 (41.7MWh@$15/MWh)
FCAS Costs	$ 1,250 (41.7MWh@$30/MWh)	$ 250 (8.3MWh@$30/MWh)
Total Costs	**$1,833.3**	**$875**

Table 1 Comparing cost outcomes of the current NEMDE dispatch vs lowest cost dispatch.

While there is some co-optimisation between wholesale and FCAS markets to put capacity into the market that leads to the best outcomes for the system, central dispatch does not consider changing the size of the largest contingency to lead to lower price outcomes in this co-optimisation.

This leads to situations where generators or loads are dispatched at levels which incur greater system costs than the benefits that capacity provides.

3 The Solution

In simple terms, the proposed change is that central dispatch should constrain the output of scheduled or semi-scheduled generators or loads when:

1. It reduces the amount of contingency FCAS requirements that leads to overall cost savings to the system,
2. it does not reduce system security, and
3. it maintains market integrity.

Clause 1 uses “overall cost savings” to indicate that the savings from the reduction in contingency FCAS costs are larger than other system costs that may increase like wholesale energy.

Clause 2 indicates that system security constraints should take priority over this constraint.

Clause 3 indicates that interventions like this in the central dispatch process can negatively impact operational or commercial outcomes for participants. Where these interventions would lead to long run costs (such as a reduction in the long run efficiency of bids or loss of investor or participant confidence) that outweigh the benefits of the interventions, these interventions should not be taken.

One simple example that demonstrates this is during high wholesale price events. If there is a large generator who sold $300 caps against its output, and is curtailed to reduce the largest contingency, that may impose a very large cost on the generator due to its commercial arrangements. Additionally, even without the cap the generator would still forego revenue in these situations. A consequence of this may be that large generators sell less caps or are less investable due to the uncertainty of potentially being curtailed under this mechanism, which could lead to negative long-term impacts that outweigh the cost savings that are achieved in these scenarios.

There are though, situations where curtailing large generation or load leads to both short and long run market benefits. Finding that line of where it makes sense to curtail large generators or loads without negatively impacting market integrity is tricky, and I leave it to the commission to determine where that line is and how it can be expressed. For instance, this may be through principles, aims or other mechanisms used in these situations.

4 Interaction with *Efficiency Improvements in Contingency FCAS Cost Allocation* Rule Change

The good news is there are scenarios where everyone, including the generator or load being curtailed, is happy for that curtailment to happen. This is particularly true if runway pricing (which is the proposed FCAS cost allocation method in *Efficiency Improvements in Contingency FCAS Cost Allocation*) is implemented due to the concentration of the risk of contingency FCAS costs on the largest generators. Take an example under runway pricing where there are three large generators at a much higher output than all other generators. Due to one of a number of possible reasons, two of those generators bid in a way that will dramatically lower their outputs in the next dispatch period. This leads to a dynamic where the one remaining high output generator is essentially “stranded” far above all other generators, incurring dramatically more FCAS costs than it may have anticipated. Under this scenario it’s often likely that curtailing that largest generator would likely:

1. Save the system money; and
2. Save that generator money.

It can sometimes be hard for generators and loads to avoid this scenario as they must bid into markets before knowing their non-energy cost obligations (such as FCAS) and cannot express a bid as a price net of their non-energy costs. This means that large generators and loads may bid their higher volumes more conservatively (i.e., at a higher price) to protect against the risk of high FCAS prices. This is not a positive outcome for either the generator or the system.

In effect this curtailment from central dispatch can provide some “insurance” for large generators and loads under a runway pricing cost allocation as they know that in those tail risk scenarios where they’re “stranded” well above the next largest unit or exposed to contingency FCAS costs far above their wholesale revenue, it’s likely that central dispatch will lower their output.

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5 Implementing this in the NER

This rule change proposes:

1. That there are clear, explicit obligations on AEMO in the NER to manage contingency sizes where it lowers total costs to the system.
2. The NER should explicitly state any obligations, aims, principles, etc giving clarity on the extent that contingencies should be managed, such as not curtailing load or generation to manage the contingency size when it would lead to long run inefficiencies.
3. There should be provisions for where it is not technically or financially feasible for AEMO to do a full implementation of this obligation. These provisions should strongly encourage AEMO to implement solutions that can partially meet this obligation, and to improve on those solutions over time where prudent to do so (explained further in this rule change at *Section 8 System Costs*).

By codifying this explicitly and specifically in the NER it provides clarity to all stakeholders in how this mechanism should be expected to operate.

Currently there are relevant clauses in *NER 3.8.1 Central Dispatch*, particularly in *3.8.1(a)* and *3.8.1(b)* which could be adapted to implement this change.

6 Impact to Market Participants

Most market participants will not be impacted by this change. This will impact large generators or loads as their outputs may be reduced compared to the current arrangements. As outlined above, if implemented along-side runway pricing this may be a net positive outcome for these generators or loads as they'll often have their output reduced during times that are in their best interest, such as situations where their contingency FCAS costs would exceed the wholesale revenues they'd earn.

7 System Benefits

Better managing the size of the largest contingency puts downward pressure on total system costs and allows participants with large generators and loads to bid more efficiently, leading to better price outcomes in the long-term interest of consumers.

8 System Costs

This mechanism would need to be implemented into central dispatch, which means it's likely there's changes to NEMDE. AEMO will be able to advise on these costs.

NEMDE changes can often be expensive and complex so in the event that costs of a full implementation are currently infeasible, I would suggest exploring partial solutions until a time where it does become feasible to fully implement this mechanism.

AEMO is already reviewing this mechanism for managing system security[1] and it could be explored how this system security implementation could be applied to also achieve increased efficiencies and positive outcomes in how the market is operated.

There are estimations and rules of thumb where you can quite easily identify when it’s likely that curtailing a large generator or load is likely to benefit the system. For instance, when contingency FCAS costs are very high relative to the wholesale price and the largest generator or load is materially higher than other generators or loads. Further, there are only so many generators or loads that are likely to be in this scenario. Based on these properties there may be simple, initial implementations that achieve some curtailment outcomes (and miss others) where improvements can be made over time where it is cost effective to do so.

[1] AEMO Constraint Formulation Guidelines Section 5.9 pg 20-21