grids

4/2/2021

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

Dear Ms Collyer,

I'm just throwing in a very specific submission: If the amount of FFR procured follows something like a 'largest credible contingency', similar to the current contingency FCAS markets, then I think for the cost allocation a continuous runway should be used for these new FFR markets. Further, regardless of whether this cost allocation is deemed appropriate or not for an FFR market, it may still be appropriate for current contingency FCAS markets.

This cost allocation methodology better meets the NEO, and specific clauses in the NER, than the current proportional cost allocation used for our current contingency FCAS markets.

Even if the volume of FFR isn't procured in exactly the same way as the current contingency FCAS markets, a runway pricing cost allocation may still be appropriate. For example, if some DUIDs aren't included in the cost allocation due to providing their own inertia, or if a value other than 'output' is used, a runway pricing methodology is still compatible and still creates the correct incentives that make it superior over the current proportional cost allocation.

I've attached a paper suggesting how and why continuous runway pricing would work in the NEM for current contingency FCAS markets, and believe the points made can be extended to many of the FFR market mechanisms being considered.

I can be contacted at mitch@grids.dev and thank you for considering this submission,

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Attachment A: Runway pricing for Contingency FCAS cost recovery

This attachment proposes that the 'proportional method' for FCAS contingency cost allocation be substituted with a 'runway pricing method'. The use of runway pricing values the resilience benefits of more distributed energy generation and should contribute to more efficient investment and operational decisions in the NEM. Continuous runway pricing is already used for SRAS markets in the WEM.

Our current FCAS cost allocation method was designed 19 years ago and may have been intended as a simple transitionary method before more sophisticated and appropriate methods could be implemented. Since that time, FCAS costs have grown sharply and the growth of more distributed generation has substantially changed the changed the context in which FCAS costs recovery options should be considered.

This change is one of those improved methods, and better meets the NEO and market design principal as set out in clause 3.1.4(8) of the NER as it would more strongly incentivise behaviours that lower our electricity system costs.

Why Do We Have a Contingency FCAS Market?

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 5 minutes to get us to 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.

How Contingency FCAS Costs are Currently Recovered

Market Customers pay for lower services, Market Generators and Market Small Generation Aggregators pay for raise services. This is due to that fact that generators switching off cause raise contingency events and loads switching off cause lower contingency events.

The participant pays the costs proportional to its generation energy or load energy (called customer energy) in the region, relative to the total generation or load energy in the region.

For example, if there is 1000MW of generation, and I have 5 generators outputting at 50MW, I will pay for 25% (5x50/1000) of the FCAS Raise Costs.

In effect the cost to this Participant follows the formula:

$$PRC = TRC \times PTGO \div TGO$$

where:

PRC = Participant's Raise Costs

TRC = Total Raise Costs

PTGO = Participants Total Generator Outputs

TGO = Total Generator Outputs of all Participants

For FCAS lower the formula is the same but for Load instead of Generation

Clause 3.15.6A(f) and (g) describe the full calculations.

This calculation gives no consideration to the composition of each participant's portfolio. For example, Participant A with 100 1MW generator outputs will be paying the same contingency FCAS raise costs as a Participant B with a single 100MW generator output. Not only is this not at all cost reflective to each participant's contribution to the need to procure contingency FCAS services (Participant A and B create 1MW and 100MW contingency events respectively), it only very weakly discourages behaviours that increase contingency FCAS costs borne by us all.

Why Do We Use A Proportional Method?

Back in 2001 the ACCC made a determination[1] that created the 8 FCAS Markets that we know and love today. There was much discussion on the ways to allocate contingency FCAS costs. Here's a few:

> *"Hazelwood supports calls for including TNSPs in the FCAS cost allocation."* – pg18

[1] NEC - Ancillary Services Amendments Determination 11 July 2001

> *"Southern Hydro states that because small and distributed generators will not impact on such frequency deviations, they should not be included in the cost allocation, and to do so will impact on the viability of such plant."* – pg13
>
> *"Tarong Energy, Loy Yang Power and Hazelwood Power (Hazelwood) have concerns regarding the cost allocations for contingency FCAS (contingency raise services)… that frequency fluctuations occur due to load switching, in particular hot water load, and argues that the cost should take into account the probabilistic nature of the cause of the requirement."* – pg 13

As you can see, many ways to allocate costs. On the actual determination from the ACCC, from page 34:

> *"Contingency costs are to be allocated 100% to generators for raise services, and 100% to market customers for lower services. This allocation is a very loose causer pays approximation, reflecting the impact of generator and large customer trips on the system.*
>
> *The LECG report to NECA mentions that spreading these costs over as broad a base as possible, until more sophisticated mechanisms are implemented, should minimise distortions to decision making during the transition. Substantial progress is envisaged in the second phase toward a structure where costs are borne by entities that can act to reduce the costs of these ancillary services.*
>
> *Allocating contingency FCAS costs on a better causer pay basis is not technically possible at this stage, and any review of the cost allocation should also consider the role of network outages in causing a need for contingency FCAS. Further, given that contingency FCAS is usually required in response to an unintended outage, it is not clear that a direct attribution of costs (where measurable) will result in changes to behaviour. The Commission considers that the proposed cost allocation is an improvement over the current cost allocation, but more work needs to be undertaken by NEMMCO in the ongoing review of ancillary service arrangements to develop a more effective causer pays arrangement (see condition C3.1)."*

In summary, back in 2001 a simple cost allocation method was chosen to spread the costs broadly as a temporary measure before a 'second phase' of work could be done to explore better ways to allocate costs. A particular objective would be to structure costs in a way that they a borne by entities that can reduce the costs of the ancillary services. A main barrier to more sophisticated and effective methods was that it was not technically possible at the time.

Proposed Approach: Recovering Contingency FCAS Costs with a Runway Pricing Methodology

The proposed alternative approach is best illustrated by way of example: Say there's three generators. Two generators (A and B) are outputting at 100MW, and one generator (C) is outputting at 150MW. Using a runway pricing methodology, all three generators would pay proportionally for the first two thirds of the contingency FCAS costs, and generator C would pay for all of the last third of contingency FCAS costs. This would mean that A and B pay 22.2% each (one third of two thirds) and C pays 55.6% (one third of two thirds plus one third).

The reason this is called runway pricing is to do with economists, airport runways, different planes that need different amounts of runway, and how do you allocate the costs of the runway when the runway is sized to your biggest (or heaviest) planes but not all planes need the entire runway? There's a lot of parallels to draw between that and how and why we procure the total amount of contingency FCAS volumes, and therefore costs. In summary, the smaller planes only have to pay for the length of runway they use, whereas the larger planes have to pay for use of the whole runway. Applying this principle to power generation would mean that larger generators and loads should be pay for the additional FCAS requirements they impose on the system.

The WEM uses runway pricing to allocate their version of FCAS Raise costs (they call it SRAS). Here is an example I've taken from a WEM document showing an example of runway pricing to allocate FCAS Raise costs in a little system with 5 generators outputting between 45-300MW[2]:

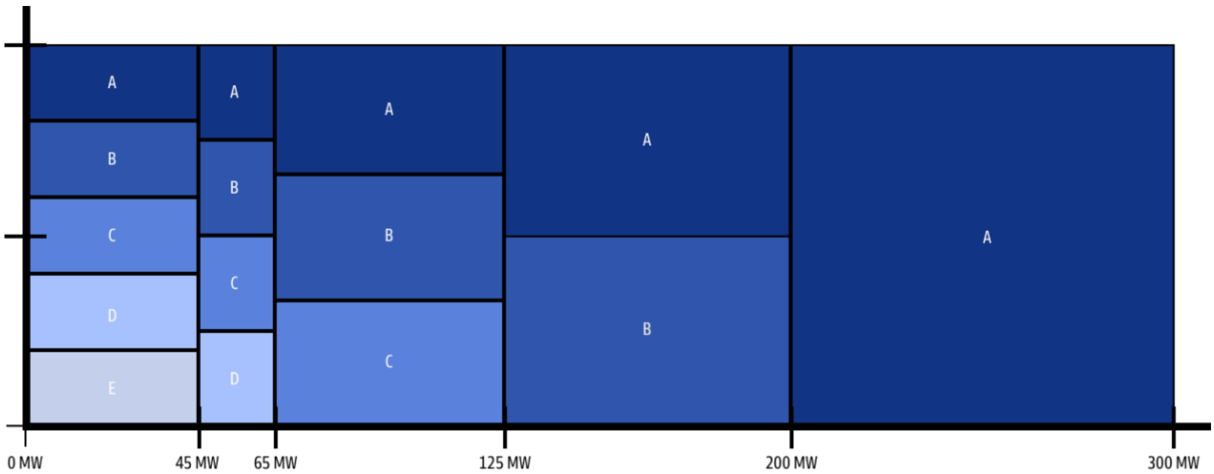

Figure 1 Runway pricing cost allocation example between 5 generators of varying output

[2] WEM Metering, Settlement & Prudential Calculations version 2.0 p78

Table 1 Proportional cost allocation and runway pricing cost allocation comparison between 5 generators of varying output

Generator	**A**	**B**	**C**	**D**	**E**
Output (MW)	300	200	125	65	45
Current cost factor (%)*	40.8	27.2	17	8.8	6.1
Runway cost factor (%)	57.2	23.8	11.3	4.7	3

*Using the proportional method of generator output/total generator output

Here are some of the calculations as an example of the method. This is for generator A:
(45/300)*(1/5)+(20/300)*(1/4)+(60/300)*(1/3)+(75/300)*(1/2)+(100/300)*(1/1)=0.5716

For generator B the same calculation is applied without the final 1/3 that is allocated fully to generator A:

(45/300)*(1/5)+(20/300)*(1/4)+(60/300)*(1/3)+(75/300)*(1/2)=0.2383

Then so and a so forth until you get to generator E:

(45/300)*(1/5) = 0.03

The equivalent cost factor allocations could be done for FCAS lower based on load.

The runway pricing calculation itself is in here in the WEM document[3] and I've included it in the appendix. *Table 1* is also an example of applying that calculation. This attachment proposes that the 'proportional method' for FCAS contingency cost allocation (proportional to a participant's share of total generation or load) be substituted with a 'runway pricing method' (that reflects a participant's contribution to FCAS procurement requirements). The proportional method is used in 3.15.6A(f) and (g) or the NER. The proportional method is bolded below.

NER clause 3.15.6A(f) Raise Cost Allocation for Market Generators and Market Small Generation Aggregators:

$$TA = RTCRSP \times \frac{\boldsymbol{TGE + TSGE}}{\boldsymbol{RATGE + RATSGE}} \times -1$$

Instead, the requested change is:

$$TA = RTCRSP \times PARTICIPANT\ RUNWAY\ COST\ FACTOR \times -1$$

NER clause 3.15.6A(g) Lower Cost Allocation for Market Customers:

$$TA = RTCLSP \times \frac{\boldsymbol{TCE}}{\boldsymbol{RATCE}} \times -1$$

Instead, the requested change is:

$$TA = RTCLSP \times PARTICIPANT\ RUNWAY\ COST\ FACTOR \times -1$$

The above example in *Table 1* calculates the factor for each individual generator (and could be equivalently done for load), the factors would need to be summed for each participant. E.g. If I was the Market Generator for generator B and C my 'participant runway cost factor' would be 35.1%.

If it is considered technically infeasible to use all generator and load outputs in the calculation due to cost and complexity a threshold can be chosen where any load or generation amounts below the threshold are not included in the calculation. A low enough threshold, say, under 5MW, will not materially change the allocations to those generators or loads left in the calculation. It's a technical consideration that I defer to Commission and AEMO on whether it's necessary and if so, what the threshold should be.

[3] WEM WHOLESALE ELECTRICITY MARKET RULES (7 August 2020) p540

Impact to Market Participants

What you can see in the example (*Table 1*) is that larger generators (A and B) and loads end up paying a larger percentage of contingency FCAS costs in the runway methodology than in the current proportional methodology, and the smaller generators pay less. This is not a flaw or drawback in the methodology this is literally the mechanism that makes all the good things for the system happen.

One relatively minor, but positive impact is that generators and loads would have greater control over the contingency FCAS costs they incur. An example of this is that currently when the largest generation/load source increases or decreases its output, most of the costs or savings are borne by the other generators. Runway pricing would concentrate a larger proportion of the cost or saving on to that largest generator and therefore each participant's costs would be more correlated to their own output and less to the largest generation or load source's output.

System Benefits

Runway pricing more strongly encourages a lower output of the largest generator or load in both the short term (through operational decisions) and long term (through investment decisions), which lower the amount of contingency FCAS volumes required (at times when a network element is not the largest contingency) placing a downward pressure on contingency FCAS costs.

Here's a very direct and simplified example of how it might work:

As the largest generator is incurring higher (than current) $/MW contingency FCAS costs for its price bands in its higher outputs, it may reflect this in higher (than current) $/MW energy bids in the higher price bands.

As the smaller generators are incurring small $/MW contingency FCAS costs for their outputs they may reflect this is lower (than current) $/MW energy bids in their price bands.

Due to this there are some scenarios where the largest generator would get dispatched in its higher price bands today, but under runway pricing it would not. If it were not dispatched in its higher price bands then it's total output would be lower so the total amount of contingency FCAS volumes required during that period would be lower, which in turn tend to cause lower prices.

This effect holds, but weakens, for the second highest output generator, and so on.

It's important to note that you don't need both the biggest generator and smaller generators changing their bids for this effect to happen. If any generator changes its bid due to runway pricing that causes the largest generator to be dispatched at a lower output than it would have without runway pricing, then the positive consequence of runway pricing has been achieved.

Runway pricing also more appropriately allocates the costs to the participant or investor of building extra generation or loads that may incur extra contingency FCAS costs on the system. Here is a very simplified example of how it could impact long term investment signals:

> *Investor: "I would like to build a very big generator. Twice as big as other generators."*
>
> *Consultant: "You will pay a ridiculous amount of contingency FCAS costs. Potentially over half the contingency FCAS costs of the entire NEM!"*
>
> *Investor: "That is a lot of money, I will now look at building smaller generators instead."*

A more realistic scenario on the generation side is if you are considering building a large asset that will last for decades you may have to consider that as other large assets are retiring over the next decade or two, you may be left with an asset much larger than the remaining assets in the future, and therefore would incur large contingency FCAS costs during that future period.

Looking specifically to the National Electricity Objectives, runway pricing promotes efficient investment in, and efficient operation and use of, electricity services for: price. As lower contingency FCAS volumes means lower contingency FCAS prices, and lower total system costs hopefully means lower power bills.

Also, it may promote system resilience. I suspect that the larger the 'single biggest credible contingency', the less system resilience there is, as even if you procure enough reserves for that contingency, the larger the contingency the larger the rate of change of frequency if that contingency occurs within in the system. This may be resolved through primary frequency and fast frequency services in the future.

As runway pricing provides stronger incentives to lower FCAS volumes, and therefore costs, it also better meets the design principal set out in 3.1.4 (8) in the NER:

> *"Where arrangements require participants to pay a proportion of AEMO costs for ancillary services, charges should where possible be allocated to provide incentives to lower overall costs of the NEM. Costs unable to be reasonably allocated this way should be apportioned as broadly as possible whilst minimising distortions to production, consumption and investment decisions"*

System Costs

The implementation would require updating AEMO settlement systems to reflect this new methodology. This methodology is currently used by AEMO in the WEM.

Should Network Elements Be Included in Contingency FCAS Costs?

Referring to the 2001 ACCC determination on contingency FCAS costs[4]:

> *"any review of the cost allocation should also consider the role of network outages in causing a need for contingency FCAS."*

Network elements like interconnectors currently don't incur contingency FCAS costs, in effect they have a 'contingency FCAS cost exemption'. Sometimes they are the largest credible contingency and therefore the FCAS 'volume setter', and so in principal imposing contingency FCAS costs on the network element may lead to lower system costs.

A question I pose to this commission is: would putting contingency FCAS costs on to network elements, and in particular using the stronger incentives of runway pricing, provide incentives to lower costs in the NEM (through reduced contingency FCAS volumes)? If so then it follows that network elements should also be included in the cost allocation.

I am unsure of the answer, so this attachment only addresses changing the cost allocation factor for how raise costs are allocated to generators, and lower costs allocated to loads, but the same arguments may in principals apply to network elements too.

[4] https://www.accc.gov.au/system/files/public-registers/documents/D01%2B22703.pdf p34

Appendix

Current SRAS Cost Allocation factor calculation from the WEM[5], which could be adapted to the NEM. Note this is just the factor and would then be multiplied by the RTCRSP and -1 to get the Trading Amount:

Step 2: For Trading Interval t, rank all applicable facilities in ascending order from the facility with the lowest applicable capacity to the facility with the highest applicable capacity, as determined in accordance with Step 1. If two or more facilities have the same applicable capacity in Trading Interval t, these facilities are ranked in random order by AEMO.

Step 3: For each facility f determine the Facility Spinning Reserve Share for Trading Interval t as:

$$FSRS(f,t) = \sum_{i=1}^{rank(f,t)} \frac{MW(i,t) - MW(i-1,t)}{MW(n,t) \times (n+1-i)}$$

Where:

n is the total number of applicable facilities in the ranked list for Trading Interval t determined in Step 2.

rank(f,t) is the rank of facility f for Trading Interval t, as determined in Step 2.

MW(i,t) is the applicable capacity of the facility with rank i for Trading Interval t, where MW(0,t) = 0.

Step 4: Calculate the SR_Share(p,t) value for Market Participant p for Trading Interval t as:

$$SR\_Share(p,t) = \sum_{f \in F} FSRS(f,t)$$

Where:

F is the set of applicable facilities belonging to Market Participant p.

f is a member of the set in F.

FSRS(f,t) is the Facility Spinning Reserve Share for facility f in Trading Interval t calculated in Step 3.

[5] WEM WHOLESALE ELECTRICITY MARKET RULES (7 August 2020) p540