Department of Energy, Mines, Industry Regulation and Safety
Energy Policy WA

GOVERNMENT OF WESTERN AUSTRALIA

Minutes

Meeting Title:	Essential System Services Framework Review Working Group (ESSFRWG)
Date:	26 March 2025
Time:	3:00pm – 4.50pm
Location:	Online, via TEAMS

Attendees	Company	Comment
Dora Guzeleva	Chair, Energy Policy WA (EPWA)	
Alex Gillespie	Australian Energy Market Operator (AEMO)	
Christopher Wilson	AEMO	
Oscar Carlberg	Alinta Energy	
Andrew Scarfone	AGL	
Lekshmi Jaya Mohan	BP Australia	
Stefan Scagnetti	Bluewaters Power	Proxy for Dimitri Lorenzo
James Eastcott	Clean Energy Council	
Julian Fairhall	Economic Regulation Authority (ERA)	
Bronwyn Gunn	EPWA	
Jenny Laidlaw	EPWA	
Shelley Worthington	EPWA	
Noel Schubert	Expert Consumer Panel	
Ali Kharrazi	GHD	
Christian Schaefer	GHD	
Jesse Singh	GHD	
Dennis Stanley	GHD	
Max Collins	Neoen	
Daniel Randazzo	Shell Energy	
Bobby Ditric	Summit Southern Cross Power	
Brad Huppatz	Synergy	
Rhiannon Bedola	Synergy	
Peter Huxtable	Water Corporation	
Mark McKinnon	Western Power	

Apologies		
Dimitri Lorenzo	Bluewaters Power	
Mark Lee	GridBeyond	
Mark McPartland	Nomad Energy Pty Ltd	
Graeme Ross	Simcoa	
Charlie Caruso	Smart Energy Council	
Dev Tayal	Tesla	
Reece Tonkin	Woodside	

1. WELCOME

The Chair opened the meeting with an Acknowledgement of Country and asked members to note the Competition and Consumer Law obligations.

2. INTRODUCTIONS AND ATTENDANCE

The Chair noted the attendance, including new members and apologies as above.

3. ESSENTIAL SYSTEM SERVICES FRAMEWORK REVIEW

The Chair opened the discussion noting that:

- the Essential System Services (ESS) Framework Review (Review) is a statutory review under Section 3.15 of the Wholesale Electricity Market (WEM) Rules;
- it is a technical review of the ESS requirements against the Standards, that incorporates a sensitivity analysis to assess the impacts of increasing or decreasing the requirements;
- it includes a review of the Supplementary Essential System Services (SESSM);
- the ESSFRWG 26 February meeting minutes are out for comment and will be provided to the Market Advisory Committee at its next meeting.

Mr Schaefer stated that the slides would be assumed to have been read.

Mr Schaefer presented slides 4 – 5 (technical issues identified).

Mr Schaefer presented slide 6 (key findings of the technical assessment) noting that, given frequency has been maintained within the prescribed limits, the focus is on the methods of quantification of ESS requirements and procurement, and whether they are fit for purpose.

- With regard to Issue 1, Mr Ditric noted that when there is a very high Contingency Reserve Raise (CRR) requirement, NewGen Kwinana (NewGen) is often turned down by quite a large margin creating unnecessary shortfalls, and this can cause increases to the Real-Time Market prices. He offered to provide GHD with examples of this.

Mr Schaefer presented slide 7 (FOS technical parameters - impact of conservatism), noting that:

- the DFCM is used to define the CRR offset that goes into WEMDE for the purpose of dispatch, whereas the Real Time Frequency Stability Tool is used by the control room to verify system security and is the basis for decisions by the AEMO control room to intervene and direct when more CRR is required - both processes look to achieve the same thing but appear to have different inputs; and

- the GPS Ride Through Requirements as listed on the slide are significantly higher than the Rate of Change of Frequency (RoCoF) Safe Limit. He acknowledged that, while the Technical Requirements do need to be a higher than the RoCoF Safe Limit, they may be set unnecessarily high in this instance.
- Mr Carlberg asked if increasing the RoCoF Safe Limit decreased the amount of CRR AEMO was required to procure.

In response to Mr Carlberg's question, Mr Schaefer noted that increasing the RoCoF Safe Limit would mean a steeper RoCoF, necessitating either more, or faster CRR as the frequency nadir would be reached more quickly, and that the interdependencies between the variables that are involved in managing frequency present challenges.

Mr Schaefer presented slide 8 (frequency of AEMO market intervention).

Mr Schaefer presented slide 9 (transparency of the process), noting that in many cases documentation is either inadequate or non-existent. This makes it:

- difficult for Market Participants to understand the processes;
- challenging for the Coordinator of Energy to review the effectiveness of the market;
- challenging for AEMO to communicate why certain actions are needed.

He added that GHD considers that the establishment of a register of the required documentation and content specification, as well as visibility about timelines for yet-to-be published documentation, will be of benefit.

Mr Schaefer presented slide 10 (impact of the largest credible supply contingency (LCSC) on RoCoF services).

Mr Schaefer presented slide 11 (ignoring Primary Frequency Response (PFR) of unaccredited facilities), noting that most jurisdictions examined require a mandatory 4% droop to assist with frequency management. He added that ignoring these contributions could be overlooking material benefits to frequency management, and the mandatory PFR could be the underlying reason for the good management of frequency in the WEM. He suggested a monitoring program to track the amount of headroom available from unaccredited or non-dispatched FCESS facilities to understand the potential contribution of mandatory PFR.

Mr Schaefer presented slide 12 (performance factors), noting that performance factors are a multiplier to the effectiveness of the CRR services that could be provided and change dynamically with the size of the LCSC and system inertia. He noted that excluding generators based on their performance factor may create shortfalls or require the dispatch of more expensive facilities.

Mr Schaefer presented slide 13 (expansion of the ESS resource pool), noting that other jurisdictions (e.g. Ireland) procure CRR services from wind farms. Mr Schubert asked if there are barriers to renewables with headroom being able to participate and if this has been considered.

- Mr Wilson confirmed there are currently no barriers in place should a semi-scheduled facility wish to accredit, but that AEMO would need to be able to assume that a certain amount of headroom could be maintained.

The Chair noted that aggregators have advised that they are very willing to participate in CRR services, subject to some of the requirements being relaxed, but that there is 1.3 gigawatts of very fast responding Electric Storage Resources (ESR) currently assigned Capacity Credits and another 640 megawatts (MW) of very fast responding ESR entering through the Capacity Investment Scheme (pending certification) from 1 October 2027. The least cost provision of CR services needs to be considered, as the new State Electricity Objective requires security to be balanced with cost and emissions.

- Mr Fairhall noted that new technologies are not likely to be zero cost and:

- currently RoCoF Control Service (RCS) is provided by conventional generators, who cannot separate the inertia from their energy market offers, hence the offer price cap being zero;
- new technologies entering, i.e. synchronous condensers (syncons) or batteries providing synthetic inertia, will require the ERA to revisit those price caps;
- it will still be weighted towards those zero cost services from conventional generators.

The Chair noted that up to a third of Capacity Credits may be allocated to ESR capable of providing CRR and synthetic inertia in the future.

- In response to Mr Fairhall, Mr Ditric noted that the provision of RoCoF is only provided at zero cost by a facility when they are making money from producing energy, and that it is not provided at zero cost if energy prices were negative/below short run marginal cost, which is typically when intervention events/directions occur.
- Mr Fairhall noted that this was when uplift payments come into play but agreed that this is not properly accounted for in the co-optimisation process.

The Chair agreed and noted that:

- Procurement and compensation for inertia brought on to address shortfalls required consideration, particularly for resources that may not be energy producing.
- Since November 2024, AEMO has had to manually direct facilities to either synchronise or remain synchronised to provide inertia to the system. This was an effective short-term backstop to make sure sufficient inertia was available while not paying for services that are provided as a by-product of producing electricity. However, this was unlikely to be sustainable in the long run.

- Mr Schubert noted that the Australian Electricity Market Commission was currently looking into inertia services.

Mr Schaefer presented slides 14 and 15 (jurisdictional comparison), making the following points on the insights/observations listed on the slides:

- 1: other jurisdictions have multiple markets and services, for example the National Electricity Market (NEM) has a very fast frequency response market for a one second response and a fast frequency response market for six seconds, meaning that it's relatively simpler to procure the right service. The shallow market in the WEM means there is not enough competition for multiple markets, but the single market for each type of service creates more complexity in dispatch;
- 2: in New Zealand (NZ), the provision of mandatory primary frequency response (PFR) is the reason very little Regulation services are procured, other than for the correction of the area control error;
- 3: in the NEM and Ireland minimum synchronous generation requirements are mandated for system strength purposes, and facilities are often dispatched at minimum generation levels leaving significant headroom;
- 4: system inertia is set at minimum levels in both the NEM and Ireland. NZ has not done so because 90% of the fleet is synchronous, but will likely do so once instantaneous non-synchronous generation penetration levels reach 50%, which is likely five to ten years away;
- 6: in other systems it is the single largest generator rather than a single line contingency (that considers multiple generators) that sets the LCSC;
- 9: in Ireland most of the renewable generation is wind, which is susceptible to voltage drops arising from power reduction. The small geographic area means weather fronts affect a large portion of the fleet. Ireland has a frequency ramping service driven by voltage fluctuations;
- 10: Ireland is moving away from a contract-based to a market-based structure.

Mr Schaefer presented slide 16 (PFR and minimum conventional generation) and noted that retaining more headroom has shown benefits in other jurisdictions and may be worth considering in the WEM.

- Mr Schubert asked if there is a technical reason for preventing faster acting generators and batteries from having lower droop settings so that they contribute more through mandatory PFR. He stated that, as demand and generation increase in variability, this should be a focus.

Mr Schaefer responded that the droop settings for some batteries in South Australia were as low as 1.2%, and noted that AEMO has indicated that any lower than that means power is injected so quickly that special protection schemes on other facilities respond as though a contingency has occurred. He added that lower droop settings create more wear and tear on mechanical governors, which is why synchronous generators are usually set to 4-5%, and that a droop change is still limited by the ramping rate of the synchronous generator (i.e. lowering the setting may create more droop response but not necessarily faster response).

- Mr Schubert agreed that there were some limitations, but that the mechanical limitations were not the case for inverter connected batteries and asked whether it was worth exploring if they could provide a more mandatory frequency response. He noted that there were systems that have some generators in isochronous (0% droop) that manage the system frequency completely.
- Mr Wilson advised there was a Facility operating in the WEM at 2% droop.

Mr Schaefer agreed that there is certainly an opportunity to consider it, but that the impact needed to be considered. He noted that a droop setting of 2% would mean that for 1 Hertz change in frequency a facility would go from zero to full output, subject to energy availability.

- Mr Schubert noted that this effectively means that the faster machines grab more load.
- Mr Huppatz noted that lower droop settings for batteries would increase the cycle related degradation rate.
- Mr Wilson reiterated that AEMO is looking into the RoCoF Safe Limit, use of synthetic inertia and documentation for the Regulation Baseline Model.
- Mr Gillespie added that AEMO will continue to work with GHD and EPWA on how documentation can be improved to ensure transparency.

The Chair noted that the work was underway by AEMO, but highlighted that given this is a statutory review and AEMO had not yet completed the work, these will still be included as recommendations, including the expected timeframes for completion.

- Mr Wilson agreed and noted that timeframes could be discussed in due course.

Mr Schaefer presented slide 18 (sensitivity analysis), noting that this was more of an economic benefits assessment as required under the rules.

Mr Schaefer explained the assessment process of the relationship between the technical parameters and the total cost as presented on slide 19 and 20 and noted that:

- sets of data were selected to run a multiple linear regression analysis, using large amounts of data to develop a correlation between input variables and outputs;
- the process was very challenging, and it became apparent that a multiple linear regression was not feasible using the datasets.

Mr Schaefer presented slide 21 (sensitivity analysis – challenges with linearising a non-linear process), noting that:

- the cost of CRR services fluctuated and did not include the CRR offset costs that might be associated with it;
- there was no correlation between CRR FCESS uplift and market prices.

Mr Schaefer presented slide 21 (sensitivity analysis – preliminary insights) and noted that linear regression would require variation of input variables that are fixed in the WEM (e.g. the FOS, RoCoF Safe Limit). With regard to the pattern of CRR dispatch following the pattern of energy demand, uplift payments are the largest cost component, as when demand is high, energy prices are high and so are the uplift payments.

Mr Schaefer noted that given these challenges, the sensitivity assessment would be limited to observing general trends and identifying relationships, and speculating on the potential effect or outcome of changes without quantifying them.

- Mr Ditric considered that uplift payments should be higher when energy prices are lower, as uplift payments are compensating for lost revenue/costs incurred.

The Chair agreed.

- Mr Ditric added that when there are high CRR costs there tends to be more constraints imposed to reduce the LCSC, which can increase energy costs. As an example, when there are very high CRR prices NewGen tends to be constrained as WEMDE considers that cheaper than acquiring more CRR, but this loss of comparatively cheaper generation increases the energy price.

The Chair noted that decreasing any of the service requirements may carry some risk and would need to be done carefully, but reiterated the need to determine whether the requirements are set at a conservative level and, if so, examine the materiality of that on the costs in the market (including flow on costs).

- Mr Schubert noted that on slide 22, the period of October 23 to September 24 was prior to the November 2024 ESS rule changes. He asked if GHD anticipated getting good results from examining market behaviour prior to those November rule changes, or whether the analysis should start at November 2024.

Mr Schaefer responded that only 12 months of data had been extracted, that this was a very challenging process and consideration needed to be given to whether it was possible to extract more within the project timeframes.

The Chair advised that looking at prices or costs before 20 November 2024 would likely not be meaningful due the November 2024 changes, and the $500 FCESS price cap that was in place from May to November 2024. She acknowledged that the data extraction had been a painful process and that the AEMO may need to assist with any further extraction. She further noted that the analysis will need to focus on the requirements, the way they are set and the impact of that on costs across the market rather than looking at market behaviour or market pricing data, and that the sensitivity analysis should be put on hold until the approach is clarified and the appropriate data sets to use defined.

The Chair and GHD agreed to discuss data extraction and the nature of the sensitivity analysis offline.

- Mr Schubert agreed with Ms Guzeleva and noted that, while it's difficult, that the purpose is to try and vary some of those static inputs in WEMDE and see what the effect of that is.

Mr Schaefer replied that this would require use of AEMO's DFCM to run different scenarios.

- Mr Huppatz noted that excluding the periods prior to November 2024 would exclude periods of low load, which is an area of concern as they are periods with high levels of PV penetration and low inertia from scheduled generation, which drives higher FCESS quantities.

The Chair reiterated that:

- the review must determine whether the requirements are set at the most cost-efficient level;
- there is a need to specify exactly what the sensitivity analysis is trying to do against the requirement of the rules, and what the right data to achieve this is;

- the intent is not to analyse pricing trends in the market more generally, but rather it is about the level at which the requirement, for a particular service, in a particular scenario or number of scenarios, is set and examining limited sets of data for those scenarios;
- the scenarios should reflect times when there is concerns about over procurement of FCESS (may be minimum or peak load);
- the sensitivity analysis does not need to produce an exact dollar value of adjusting the requirements, but is an assessment of materiality;
- EPWA and GHD will liaise to ensure that the data set that is used is sufficient.

Mr Schaefer presented slide 24 (SESSM – intent and purpose) and noted that the SESSM to date has not been triggered.

Mr Schaefer presented slide 25 (SESSM in action) nothing that he considered that the SESSM process could take 1-3 years and won't address immediate shortfalls.

The Chair noted that NCESS and SESSM timeframes are likely to be similar, but the question is do the rules need to differentiate between services procured through the SESSM that can be fully co-optimised, or those that cannot be fully co-optimised (under the current rules) because they are not provided by energy producing facilities and therefore need to be compensated in some other way for the services they provide.

Mr Schaefer explained that he did not consider that the NCESS was a short-term fix, rather that there were similar aspects between the NCESS and SESSM procurement processes.

The Chair agreed and noted that the requirement needs to be projected well in advance for either of those processes.

Mr Schaefer presented slide 26 (SESSM – challenges and inadequacies of the existing process).

Mr Schaefer presented slide 27 (SESSM – case study), noting that:

  - GHD is looking to test the gaps in the SESSM process;
  - RCS is challenging to work through as the price for it is zero on the assumption that it's a by-product of producing energy;
  - a case study to ascertain whether the SESSM was fit for purpose using RCS had been planned but that was now paused to focus more on assessing the process, applicability and implementation of the SESSM for the other four FCESS;

- Mr Fairhall noted that, if syncons were used to provide RCS, that would likely trigger a review of the offer price ceiling for RCS. Currently it is set as zero because the only Facilities that are accredited to provide it cannot differentiate the RCS they provide from their energy. He added that an increase in the offer price ceiling may then result in more offers to the market.

The Chair agreed with Mr Fairhall and noted that:

- a non-energy producing RCS cannot be accommodated within the current market design. Many current rules, including the cap would not work, for this circumstance;
- it is likely more practicable to review the NCESS framework to make sure that such a service can be procured and compensated separately;
- it would be beneficial to explore any synergies between the need of Western Power to procure System Strength Services and AEMO's need for RCS from services like syncons, at the same time.

The Chair advised that the SESSM portion of the review would be placed on hold to consider the above issues.

- Mr Schubert stated that the WEM was more likely to get synthetic inertia and RCS from the batteries. He agreed that redesigning the SESSM to procure syncons would be complicated and questioned the need to do so with so much battery capacity coming in.
- Mr Wilson confirmed that AEMO was actively looking into synthetic inertia and that one of the advantages with synthetic inertia is that there is no longer a commitment issue in the market. This was largely because inverters, even if they are at 0 MW can still remain synchronised to the grid, allowing an inertia like service without any energy associated with it.

The Chair noted that, if there are any costs to provide synthetic inertia, those costs should be compensated.

- o Mr Collins advised that providing synthetic inertia does come at a cost, but this is very small. He advised that a good case study to consider would be the UK, in particular the stability Pathfinder contracts which show that the battery contracts are virtually free when compared to syncons. He added that a market signal for participants to be developing batteries with grid forming inverters could yield good results. He suggested that there could be a mechanism for new batteries connecting to offer a price for 15 years of an inertia service.

The Chair agreed that the mechanism would need to be worked through as this currently is not enabled by the rules, and that there was a Power System Security and Reliability Standards Review with a Consultation Paper (yet to be published) that covers connection standards for grid forming inverters.

- Mr Schubert asked Mr Collins whether existing batteries, including those being built right now, were able to be reprogrammed to provide RCS or if they would require different inverters.
- Mr Collins replied that the Collie 1 battery would be able to do grid-forming and, while it would require some CapEx and protection work, this is not significant.

The Chair noted that if a process can be created to enable the re-programming to happen and be compensated to make the service available, then that is something that should be considered.

- Mr Wilson added that, in the event that synthetic inertia is considered appropriate for RCS, the one distinction AEMO need to consider is the maximum power output of the inverters. If the battery is operating at its maximum output, there is no additional energy injection coming from it unlike physical inertia.
- Mr Collins noted that in the Pathfinder projects, the final inertia quantity was the amount that could be produced when the battery is at full import or full export, but that much more could be produced if the battery was at 0MW. He added that, if the service was rewarded, than battery operators may add additional inverters to be able to produce more inertia at full export or full import.

The Chair suggested that this would be good to discuss in another session of the ESSFRWG and to draw on the experience of Mr Collins and others as to what can be achieved in the WEM.

4. GENERAL BUSINESS

No general business was discussed.

5. NEXT STEPS

The Chair advised that there would be another working group meeting to complete discussion on the sensitivity analysis and synthetic inertia.

The Chair advised that GHD would be drafting a Consultation Paper and closed the meeting.

The meeting closed at 4.50pm.