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Submitted online: https://www.aemc.gov.au/contact-us/lodge-submission

26 September 2024

Review into Electricity Compensation Frameworks

The Australian Energy Council ('AEC') welcomes the opportunity to make a submission in response to the Australian Energy Market Commissions ('AEMC') *Review into Electricity Compensation Frameworks* Draft Report.

The AEC is the peak industry body for electricity and downstream natural gas businesses operating in the competitive wholesale and retail energy markets. AEC members generate and sell energy to over 10 million homes and businesses and are major investors in renewable energy generation. The AEC supports reaching net-zero by 2050 as well as a 55 per cent emissions reduction target by 2035 and is committed to delivering the energy transition for the benefit of consumers.

In the two years since the June 2022 market suspension, there has been continued uncertainty around the administration of the compensation regime. It is crucial to understand the underlying causes that led to the market suspension when considering regulatory reform.

The AEC is supportive of the bulk of the AEMC's draft recommendations. The AEC is pleased that the draft recommendations will assist with:

- providing clarity, consistency and timeliness to the compensation regime; and
- focus on preserving commercial decision-making to the greatest extent possible.

An appropriate compensation regime is necessary for the NEM to function smoothly at times of market stress to the ultimate benefit of energy consumers.

Constrained on generators

In its Draft Report, the AEMC's draft position is that no changes should be made to the NER regarding constrained on generators. The AEMC points to the high frequency of directions likely being resolved through the ISF rule change as the primary mechanism for the management of system security moving forward.

However, the AEC suggests that the issue is not limited to the frequency of directions, but rather whether market outcomes are being distorted through AEMO's use of constraints for managing FCAS procurement levels and minimum system load requirements – that impact mainly energy storage operators.

AEMO is required to ensure the power system is stable, reliable and secure. It has a range of tools at its disposal, one of which is to issue a clause 4.8.9 direction to market participants to comply with an AEMO specified dispatch instruction as an alternative to normal market dispatch in accordance with Clause 3.8. The ISF rule change moves towards restoring the use of a direction as a last resort mechanism. However, we are concerned that under AEMO's current proposal to market participants, energy storage is likely to at times be constrained on for both generation and charging and alternatively constrained off from charging in certain circumstances, particularly in the case of AEMO seeking to maintain minimum system load requirements.

This Compensation Review has set out to correct potential perverse market outcomes that result from inadequate compensation for generators. What this new proposal from AEMO, with regards to management of minimum system loads highlights is that there will be future currently unknown proposals from AEMO where generic (non-network) constraints may be utilised for secure operation of the power system regardless of the impact this has on efficient dispatch and participants economic outcomes.

In addition to other conflicts between AEMO's proposal and the NER, it also contradicts one of the core principles of the NEM.

3.1.4 Market design principles

(a) This Chapter is intended to give effect to the following market design principles:

(1) minimisation of *AEMO* decision-making to allow *Market Participants* the greatest amount of commercial freedom to decide how they will operate in the *market*;

(2) maximum level of *market* transparency in the interests of achieving a very high degree of *market* efficiency, including by providing accurate, reliable and timely forecast information to *Market Participants*, in order to allow for responses that reflect underlying conditions of supply and demand;

(3) avoidance of any special treatment in respect of different technologies used by *Market Participants*;

(4) consistency between *central dispatch* and pricing;

We are concerned that AEMO may be using generic (non-network) constraints instead of directions to determine when energy storage participants should charge to manage minimum system loads for system security purposes. There have also been instances when AEMO has reduced generator active energy output or non-scheduled and scheduled load consumption to manage FCAS procurement levels. Constraints imposed in the normal dispatch process were not meant to be used this way, and this is likely to lead to unintended consequences. Storage operators consider closely their opportunity cost and losing the ability to make decisions around charging and discharging cycles could have serious consequence on the investment signals in these assets.

A generator is compensated when directions are issued but not when a generic (non-network) constraint is imposed by AEMO during NEMDE dispatch. We consider that addressing this issue by ensuring the compensation framework ensures just compensation when efficient dispatch is altered by AEMO would result in better outcomes for consumers, while also future proofing NEM operation. This is an opportunity to analyse current and potential future developments that could have negative impacts in the long term without the need to wait for the consequences to come to fruition.

Draft recommendation 1: Each compensation framework should have an objective, and the objective for directions compensation should be to enable generators to be compensated for the costs associated with complying with a direction. The administered pricing and market suspension frameworks will remain the same.

The AEC is supportive of the approach to objectives outlined in Draft Recommendation 1. In relation to the specific wording, consideration should be given to amending the objective for directions compensation to include "costs, including opportunity costs" in the interests of clarity. This would ensure Draft Recommendation 2 is understood in the objectives drafting.

Draft recommendation 2: Participants should be eligible to claim opportunity costs in each

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of the directions, administered pricing and market suspension compensation frameworks.

The AEC supports Draft Recommendation 2 that participants should be eligible to claim opportunity costs in each of the directions, administered pricing and market suspension frameworks.

Opportunity costs exist regardless of which approach is used to bring generation into the market, whether it is by constraining on, direction, market suspension or administered pricing compensation. For all energy limited scheduled generators, a MWh that is dispatched at one time cannot then be dispatched again at a later point in time. That means that by being forced to dispatch at a time when they otherwise may not otherwise choose to be available in the market, they are forgoing the potential revenue at a different point in time.

Opportunity costs must also have regard to the underlying economics of different types of generation. For example, for battery energy storage systems (BESS), the value of having BESS in the energy market is maximised when they are free to charge at times of low prices and dispatch at times of high prices. Interfering in this cycle through directions or any other framework which doesn't capture opportunity costs would damage the incentives for batteries to remain in the market at critical times. In addition, if batteries are directed to cycle when they would not otherwise choose to, it could give rise to additional maintenance costs, warranty issues and asset life cycle impacts.

For hydro, compensating based on SRMC is not a meaningful approach, as the fuel is essentially free, with the value of the water linked to market opportunities. That means opportunity cost is the only meaningful way to compensate for hydro generation. Opportunity cost is linked to marginal pricing, as in the NEM all generators, regardless of their cost of generation, receive the marginal price.

There should be opportunity cost consideration for forms of thermal generation with regards to their fuel stockpile. Having been dispatched at a time not of their choosing, a thermal generator may experience increased costs for sourcing replacement fuel that exceeds that which they might have already contracted.

The AEC, therefore, strongly supports the consideration of opportunity costs within the compensation frameworks. A more consistent approach across all three of the compensation frameworks, as previously noted, should likewise be supplemented with a consistent set of standardised direct costs, covering all potential direct costs, alongside a codified procedure for opportunity costs to be used. Codification of direct costs offers the prospect that these costs can be calculated expeditiously, with compensation paid in a timely manner. This is to the benefit of both the relevant market participants and their customers. Currently, larger customers are bearing uncertainty on costs as compensation claim payments are delayed, so any mechanism to streamline the simpler direct cost compensation is beneficial.

Draft recommendation 3: The upfront payment for directions compensation should be changed to reflect the volume-weighted average price received by assets of the same technology type in the same region for the previous 12 months.

The AEC supports Draft Recommendation 3 that upfront payment for directions compensation should be based on the volume weighted average price (VWAP) received by assets of the same technology type over the previous 12 months. The AEC supports Draft Recommendation 3 that upfront payment for directions compensation should be based on the volume weighted average price (VWAP) received by assets of the same technology type over the previous 12 months. This support is subject to the caveat that trading interval outcomes where a generator or Bi-Directional Unit (BDU) is generating active energy output due to a Direction by AEMO or generating active energy output due to dispatch of an essential systems services contract should be excluded from the VWAP calculation. The VWAP calculation should only include trading

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intervals where the dispatch instruction results from a generators or BDU's bid and not as a result of market intervention by AEMO.

While we agree in-principle that the VWAP approach is more technology specific and reflects some of the lost value when being directed, it is unclear whether this approach will sufficiently reflect the costs incurred by peaking plants that are fewer in number and dispatched infrequently (such as pumped hydro and open-cycle gas turbine).

This is likely to be an increasingly relevant consideration as the NEM transitions to a power system with a high level of VRE where peaking plants may only be dispatched infrequently (directed or voluntarily) during periods of tight demand-supply and system stress. Under the VWAP approach, the calculation of upfront compensation will exclude periods where generators have been directed. This may further reduce the already limited data points available to calculate the upfront payment and potentially make the VWAP approach more susceptible to manipulation.

If the VWAP approach leads to significant under or over compensation for peaking plants, it would create market distortions and inefficiencies (including additional claims), which would likely increase costs for all consumers. We consider that more work is necessary to evaluate the materiality of the issues raised.

Draft recommendation 4: The upfront payment for market suspension compensation should be the greater of the MSPS price and the upfront payment for directions (calculated as the VWAP).

The AEC supports Draft Recommendation 4, subject to the discussion as for Draft Recommendation 3.

Draft recommendation 5: All compensation claims should be lodged with AEMO.

The AEC agrees that a single market body, such as AEMO, should handle all claims. In our view there is little reason to have different compensation frameworks managed by different market bodies.

Draft recommendation 6: AEMO, using the independent expert function, should assess claims for administered pricing in addition to the directions and market suspension compensation frameworks. All claims for opportunity costs should be assessed by the independent expert.

The AEC believes that there should be maximum consistency across different compensation frameworks. This would help make generators indifferent about whichever compensation framework is used. Given the objective of each framework is to maintain incentives for generators to remain in the market at times of market stress, we are of the view that there is no reason for different frameworks to have different compensation frameworks.

A simplified arrangement with a single compensation approach for constrained on directions, administered pricing and market suspension compensation would work improve the framework and reduce the potential for distortions to arise. This should include compensating for the same costs across all three frameworks using identical calculations.

Draft recommendation 7: The Commission should retain responsibility for the guidelines for assessing opportunity cost claims. These guidelines will apply across all frameworks.

We support a consistent approach across the three compensation frameworks forming part of this review. We recommend that a consistent set of direct costs, which covers all potential direct costs, along with a

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codified procedure for opportunity costs be used to compensate all generators. It would be reasonable for opportunity costs to be considered over different timescales for different fuels to recognise their operating cycles. When considering direct costs, these must be determined and set such that the potential for additional costs claims is minimised. We consider the current benchmark provisions in this area are grossly deficient leading to unnecessary and time-consuming claims for additional compensation.

We support the AEMC retaining the responsibility for the guidelines to assess opportunity cost claims. The AEMC should also assure itself that its recommended AEMO Independent Expert process decisions are consistent with its guidelines, and not issue the guidelines on a set and forget basis.

Draft recommendation 8: Administered pricing compensation should be assessed by trading interval within an eligibility period rather than by net revenue in an eligibility period.

The AEC supports this draft recommendation.

Draft recommendation 9: Administered pricing compensation should be assessed on an individual unit level rather than across all units that make up a claim for compensation.

The AEC supports this draft recommendation as opportunity costs differ across technology types as set out above.

Draft recommendation 10: There should be the same time limits on all compensation claims including claims for administered pricing compensation. The time limits should be aligned with AEMO's intervention settlement timetable, which currently sets out the timeframes for directions and market suspension compensation processes.

The AEC supports this draft recommendation, and notes that the timely processing of compensation claims supports better management of energy costs, particularly for market customers.

The AEC suggests that a period of 40 days would suffice. The level of supporting information should be well defined, and not too onerous so that market participants have ample opportunity to meet the timeframes. Importantly, AEMO should also have defined timeframes for assessment of any compensation claims. Remuneration to generators needs to occur in a timely matter to ameliorate the uncertainty that has resulted from the compensation claims process.

Draft recommendation 11: The same types of direct costs should apply to all compensation frameworks and be identified in a single list.

The AEC supports codification of direct costs as a mechanism to accelerate the processing of compensation claims.

Draft recommendation 12: Cost recovery for administered pricing compensation should be determined on a trading interval basis, with costs recovered from the region where the price is set by the APC.

The AEC supports this draft recommendation.

Draft recommendation 13: Costs of capacity directions should be recovered from consumers only.

The AEC supports this draft recommendation.

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Draft recommendation 14: The same standards of supporting information should be required across all compensation frameworks.

The AEC supports this draft recommendation.

A final comment the AEC would like to make is in relation to progressing from the review stage to rule changes. It is important that the AEMC develops a clear plan to progress the review through to rule changes in a timely manner. Grouping the recommendations into rule change tranches based on level of complexity to implement might be an effective and time-efficient way to process them as there are several administrative improvements that would be relatively easy and low-cost to implement.

Questions about this submission should be addressed to David Feeney by email at david.feeney@energycouncil.com.au.

Yours sincerely,

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