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Australian Energy Market Commission

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Review into electricity compensation frameworks: consultation paper

AGL Energy (AGL) welcomes the opportunity to provide feedback on the Australian Energy Market Commission (AEMC) Review into electricity compensation frameworks consultation paper.

Proudly Australian for more than 186 years, AGL supplies around 4.3 million energy and telecommunications customer services. AGL is committed to providing our customers simple, fair, and accessible essential services as they decarbonise and electrify the way they live, work, and move.

AGL operates Australia's largest private electricity generation portfolio within the National Electricity Market (NEM), comprising coal and gas-fired generation, renewable energy sources such as wind, hydro and solar, batteries and other firming technology, and gas production and storage assets. We are building on our history as one of Australia's leading private investors in renewable energy to now lead the business of transition to a lower emissions, affordable and smart energy future in line with the goals of our Climate Transition Action Plan.

QUESTION 1: ASSESSMENT FRAMEWORK

1. Are there any other relevant considerations or principles that should be included in the assessment framework?

The assessment framework appropriately includes the principle of market efficiency. We consider that is the key principle and the basis for a framework that tries to preserve the efficient market price as set by the forces of demand and supply so that the investment signal created by that price is also preserved.

QUESTION 2: OBJECTIVES

1. Do stakeholders have any proposed changes to the objectives of the various compensation frameworks?
2. Is the reasoning behind each objective still appropriate and relevant?
3. Regarding the directions compensation framework, how do we best balance the need to avoid creating a perverse incentive to be directed with the objective of compensating directed participants fairly? How well is this achieved under the current framework?

We consider the objectives and reasoning of the compensation frameworks to be appropriate and relevant.

We consider there is value in developing a single objective unified across all three frameworks.

With regard to the concern that directions compensation may create a perverse incentive to be directed, we note that this could only ever be the case if compensation were above the market price, which at a minimum would be the short run marginal cost (SRMC) of generation, which includes opportunity costs, and otherwise the price the generator would expect to receive with reference to the impact of marginal pricing and scarcity pricing.

QUESTION 3: ACHIEVING THE OBJECTIVES

1. Do stakeholders agree with the observation that the administered pricing and market suspension compensation objectives may not have been achieved in the June 2022 events?
2. If directions compensation was preferred to the other frameworks, were there any specific reasons why this was the case?

Yes, administered pricing and market suspension compensation objectives were not achieved in June 2022 due to the inadequacy of the then $300/MWh administered price cap (APC) as that price did not reflect market prices. With the APC adjusted to $600/MWh until June 30, 2028, we consider that financial incentives are better aligned.

We consider generation availability is best served by ensuring appropriate market incentives are in place, as opposed to regulatory interventions in the form of market obligations.

QUESTION 4: METHODOLOGY

1. Do stakeholders have any suggestions related to the directions compensation framework that could enable it to more effectively meet its objective to fairly compensate directed participants without creating a perverse incentive to be directed?
2. Do stakeholders consider there is value in having different approaches to the various compensation frameworks? Would better outcomes be more likely if the frameworks were consistent where possible?

We support the AEMC’s intention to make the three compensation frameworks consistent to promote agnostic/objective generator decision making towards the framework used.

3. Should opportunity costs be considered in the compensation frameworks? If so, which ones and why?

AGL strongly supports the inclusion of opportunity costs in all compensation frameworks because otherwise participants will be compensated at a level below their short run marginal cost (SRMC). Opportunity costs are a component of SRMC and if they are excluded directed participants are effectively penalised because they are incurring a cost for which they receive no compensation.

Opportunity costs are costs incurred in choosing one option over another for a scarce resource for which there is an option of an alternate or future use. They are a key component of SRMC that ensures that scarce resources are allocated efficiently by ensuring that they are valued based on the options for their use rather than the cost at which they were acquired.

Opportunity costs are relevant in electricity generation as fuel (coal, gas, water, or electric charge) is often a scarce resource which may be used elsewhere, sold on the open market, or most commonly, used in a future high demand period. While a generator’s direct cost of obtaining fuel may be low due to legacy coal or gas contracts, free rainfall, or by charging a battery in a low-price period, generators will value scarce fuel based on their assessment of their best available option for its use. In doing so, generators are responding to the forces of supply and demand and ensuring the efficient allocation of resources, which ensures that adequate fuel is available in high demand periods.

A generator faces opportunity costs when the value of its fuel increases above the direct cost of that fuel due to a tightening of the supply demand balance of its fuel. The generator may benefit from the revaluing of its fuel on hand, as any investor benefits when the market value of an asset they hold increases, but their cost of generation increases because to supply generation they now need to use a more valuable resource. Likewise, the tight supply demand balance of fuel may drive investment in the supply of fuel, but it will not drive investment in electricity generation as it is merely an increase in costs.

Opportunity costs due to the market value of fuel increasing can be determined by accounting for the change in the value of the generator’s fuel. While determining opportunity costs due to forgone generation in a future high demand period requires consideration of the timing of when the fuel could be otherwise used and the expected value of generation in the future period. Timing considerations will depend on how much scarce fuel the generator has on hand, how much it can store and for how long, and how long the scarcity will continue. For example, the opportunity cost of generation for a hydro generator with a small amount of water generating in a low-priced period would be high if it could otherwise use that water during a summer peak but would be low if a storm were about to fill its dam. While for batteries and pumped hydro, which engage in regular arbitrage, the opportunity cost will be based on missed arbitrage opportunities and will require consideration of a shorter period.

The magnitude of an opportunity cost will be based on the opportunity forgone, which may be as high as a missed opportunity to generate at the market price cap. As a result, while we suggest compensation should include opportunity costs, we consider some mechanism to cap costs may be appropriate.

SRMC is merely the minimum level at which a generator will bid into the market, because if a generator is dispatched at below their SRMC they will make a loss. While a generator may bid at the market floor to avoid costly shutdown and later startup costs, these costs are part of the SRMC of generation at that time and the generator's SRMC is actually below the market floor in these circumstances. Compensation at SRMC with the inclusion of opportunity costs is therefore the minimum that a generator should receive because otherwise they would be forced to make a loss.

If compensation were to fully replicate market prices it would include the impact of both marginal bid pricing and scarcity pricing, which are the only forms of pricing that allow generators to cover their long run marginal costs and earn revenues that drive generation investment. Marginal bid pricing will only be relevant if the wholesale price in the directed period is above the SRMC of the directed unit, which will often not be the case since the unit has not chosen to dispatch in that period. Scarcity pricing however is relevant anytime the supply demand balance of that particular type of generation is tight, which can often be the case when a generator is directed. In these circumstances an undersupply of that type of generation will exist and prices should exceed the SRMC to reflect the undersupply and to provide an investment signal for that type of generation. While in these circumstances wholesale prices may be low, it will often be a specific attribute of that generator that the market needs (e.g. system strength or inertia) and prices should reflect the undersupply of that specific attribute. We therefore suggest that the AEMC consider whether compensation frameworks should also consider include an allocation for scarcity in addition to compensation which accounts for the SRMC including opportunity costs of a generator.

Furthermore, one particular subset of opportunity costs the current compensation frameworks do not account for are the costs associated with the additional deterioration of generation units incurred as a result of complying with directions i.e. wear and tear.

We consider there is a need to expand the way in which compensation frameworks account for generator wear and tear, so that when the particular nature of a direction requires the unit to operate in a way that causes wear and tear above that which it incurs in normal operation, the impact of this wear and tear is fully compensated. For example, directions which require a generator that was designed to operate continuously to operate in a two shift, stop/start manner can cause significant wear and tear above normal operation and should be fully compensated.

Determining the cost of wear and tear on a generation unit can also be complicated and costly and will often require an engineering study; therefore, we consider that where a generator is subject to frequent directions the cost of such a study should be able to be fully compensated.

4. Do stakeholders agree with providing more codification and guidance about how opportunity cost compensation is likely to be assessed?

Yes. We suggest such guidance be in the form of AEMO guidelines rather than new rules, so that they can be easily updated, as it may take several iterations to finalise the appropriate guidance.

5. Do stakeholders consider that changes to the compensation frameworks may be necessary due to the advent of battery energy storage systems? If so, are there any specific changes that should be considered?

If compensation frameworks appropriately include compensation for opportunity costs, then no specific changes for batteries should be required.

6. Do stakeholders consider that administered pricing compensation provides a sufficient incentive for participation in the market during an APP? If not, please explain why and include any measures that could be considered as part of this review.

We consider that administered pricing compensation provides a sufficient incentive for participation in the market during an APP; provided the level of the APC is adequately high. We support the recent increase to the APC, and its periodic review to ensure it is set at an adequate level.

7. Do stakeholders agree with the suggestions made by the AER regarding removing economic considerations for causing a direction given the availability of compensation?

We do not support the suggestions made by the AER to:

- remove commercial considerations from the list of reasonable causes for causing a direction in clause 4.8.9(c2), due to the existence of the compensation frameworks
- introduce a positive obligation on generators to continue to offer capacity into the market during actual LOR2 or LOR3 conditions during an administered price period, and
- introduce an obligation for generators to use available price bands during APP.

8. Do stakeholders have a preference for a benchmark approach to compensation such as the market suspension compensation framework, or a more open framework such as the administered pricing compensation framework?

As above, we support compensation frameworks that reflect the supply demand balance and SRMC including opportunity costs in the relevant period, plus an allocation for scarcity. We therefore do not support the proposed benchmark approach that uses static generic SRMCs that do not reflect the supply demand balance or market reality.

QUESTION 5: GOVERNANCE

1. Do stakeholders think it is appropriate to have a single point of receipt for all compensation claims to reduce confusion?
2. Who should be responsible for the various compensation frameworks?
3. Are there any other governance issues that should be considered?

We support a single point of receipt for all compensation claims to reduce complexity and potential delays in the assessment and payment for compensation claims.

We consider AEMO is best placed to assume responsibility for the various compensation frameworks.

QUESTION 6: OVERLAPPING COMPENSATION CLAIMS

1. Do stakeholders agree with the issues identified regarding overlapping compensation claims?
2. Do stakeholders agree with the potential solutions identified to address issues arising from overlapping compensation claims? Do stakeholders prefer a particular option or propose other options for consideration?

We consider the issue of overlapping compensation claims should be removed, provided a consistent approach to compensation is implemented.

QUESTION 7: TIMEFRAMES FOR SUPPORTING INFORMATION

1. Is it appropriate to include timeframes for administered pricing compensation claims?
2. Should additional time be provided for opportunity cost claims, and if so, how much?

We understand the utility in having timeframes for administered pricing compensation claims, however we suggest the timeframe should be generous because APC events are significant, and it may be challenging to assess the impact. We consider that failure to meet the deadline should not be grounds for denying the claim as APC periods occur due to a failure of system design or planning and therefore should not be subject to high regulatory burden.

We consider that the scope of supporting information should be clearly defined and not overly burdensome, ensuring that market participants have sufficient opportunity to adhere to the specified timeframes.

QUESTION 8: HARMONISING DEFINITIONS

1. Do stakeholders agree that there would be benefits in aligning definitions of cost categories across the various compensation frameworks?

We support aligning the definitions of cost categories across the various compensation frameworks.

QUESTION 9: COST RECOVERY

1. Do stakeholders consider that cost recovery provisions for administered pricing could be clarified with respect to situations where there are multiple “home regions”?
2. Do stakeholders have any thoughts on the existing cost allocation mechanisms for the compensation frameworks?

We consider there is benefit in further clarification of cost recovery provisions for administered pricing with respect to situations where there are multiple “home regions”.

We consider there is a potentially inefficient cost allocation that exists within the NER, whereby cost recovery for capacity directions is partially covered by generators. We consider that customers are the beneficiaries of capacity directions due to enhanced reliability and should therefore be financially responsible for the outcome.

QUESTION 10: INFORMATION TO SUPPORT A CLAIM

1. Do stakeholders have suggestions for NER requirements and/or guidelines changes that could provide greater clarity for administered pricing compensation claimants?
2. Do stakeholders have views on the level of evidence that is required to substantiate claims under the current compensation frameworks?

We support additional guidance from the AEMC regarding the standard of evidence required to substantiate a claim. A balance must be struck between the necessity for rigorously substantiated evidence showcasing genuine costs and the imperative to maintain a simple and clear process. This ensures that participants can provide information without encountering administrative difficulties.

If you have any queries about this submission, please contact Alifur Rahman on +61 416 00 1664 or at ARahman3@agl.com.au.

Yours sincerely,

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