AGL Energy Limited
T 02 9921 2999
agl.com.au
ABN: 74 115 061 375
Level 24, 200 George St
Sydney NSW 2000
Locked Bag 14120 MCMC
Melbourne VIC 8001

Australian Energy Market Commission

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Review into electricity compensation frameworks

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

About AGL

Proudly Australian for more than 186 years, AGL supplies around 4.5 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, 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.

Directions with intervention pricing, not constraint equations, should be used for MSL

The new Minimum System Load (MSL) procedure recently presented by AEMO proposed using constraint equations to 'move' battery energy storage systems (BESS) to charge and discharge. More recent updates suggest that AEMO may be moving away from this design attribute, a move which we support. We consider the use of constraint equations in this purpose, without first issuing a direction, a form of excessive market intervention. Without a true network or physical constraint, we consider a direction to be the appropriate mechanism for a market intervention of this kind.

Under 3.9.3(b) of the National Electricity Rules (NER) if the reason for an intervention is to obtain a service for which 'a spot price or ancillary service price is determined by the dispatch algorithm' then AEMO must set the price for the intervention interval at the price that would have applied. When a battery is being asked to discharge or absorb energy, we consider this is a service capable of being set by NEMDE and therefore intervention pricing should apply.

Requiring a BESS to discharge or charge will increase supply or increase demand and, without consideration, will influence wholesale prices in that interval. We therefore consider unless intervention pricing applies, the new proposed procedure goes against 3.9.3 (b) and will reduce wholesale prices below the economically efficient level, undermining investment signals to the detriment of generators and the long-term interests of consumers.

AEMO have indicated that the new MSL procedure is only likely to be used in record low demand conditions with network outages in 2024 and will be reviewed and potentially replaced in October 2025. Nevertheless, we encourage ongoing efforts to find a better solution or at least place an explicit expiry date on the proposed procedure so that it cannot be used at future periods without further industry debate. We are concerned that without having to start from a blank slate, with such a difficult topic, the status quo will continue. We therefore consider that consideration of the MSL procedure, and compensation under it, should be part of this compensation frameworks review.

AEMO has indicated that BESS directed under the MSL procedure will be eligible for compensation under the directions framework. AGL propose that this sort of scenario was never contemplated under the existing directions framework (particularly the concept of 'holding empty to absorb energy') and therefore it is not clear that BESS will be adequately compensated for this intervention. We therefore suggest this issue needs focused consideration under this compensation frameworks review.

Feedback on AEMC recommendations

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

AGL supports the implementation of an objective for the Directions compensation framework. We acknowledge the different compensation frameworks may need different objectives. We consider all the compensation frameworks should aim to ensure the efficient and safe operation of the NEM.

We consider the proposed objective for directions compensation to enable generators to be compensated for the costs associated with complying with a direction to be appropriate.

Furthermore, while we acknowledge the compensation frameworks are intended to be used during non-standard market conditions, we consider that they should still aim to minimise market distortions. We note the AEMC considers that directions are intended to be a last-resort mechanism to be used to manage system security and reliability. If AEMO is issuing directions on a regular and consistent basis to address the same issue, there is likely a structural issue with the market that should be addressed outside the use of directions. The objective of the Directions framework should reference its intended use as a last-resort mechanism. If this objective is breached in the future with the regular issuing of directions, then further consideration of the issue giving rise to regular directions should be investigated. This is particularly important for instances where directions are being used to fulfil the need for services which are better incentivised through a market mechanism or something similar.

Recommendation 2: Participants should be eligible to claim opportunity costs in each of the directions, administered pricing and market suspension compensation frameworks. This is a change from the current arrangements, where participants can claim for loss of revenue under the directions compensation framework, and direct costs only under the market suspension compensation framework.

AGL strongly supports the AEMC's recommendation to enable participants to claim opportunity costs in all of the compensation frameworks. As noted in our submission to the previous Consultation paper, opportunity costs are a component of short run marginal cost (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.

Generator Deterioration (Wear & Tear)

A 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, where a generator is subject to frequent directions the cost of such a study should be able to be fully compensated. We note that some of these costs e.g. to conduct an engineering study, could be more appropriately classified as direct costs, discussed further below.

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. This is a change from the current payment of the 90th percentile price for the previous 12 months in each region.

We support this recommendation to change upfront payment for Directions compensation to reflect the volume-weighted average price (VWAP) received by assets of the same technology type in the same region for the previous 12 months. We consider instances where there is a market intervention by AEMO (e.g. a direction) should be excluded from the VWAP calculation. The VWAP should only include trading intervals where the dispatch instruction results from a generators or bi-direction unit's (BDU) bid.

When assets are directed to generate in a region, they are not commercially available and are not receiving pool price (they get the 90th percentile price). The directed generation produced further supresses the pool price; noting that it is possible that directed energy in the South Australian region can, at times, be greater than the demand in that region. Therefore, periods where the market is distorted by system security directions should be excluded from the calculation of that technology's VWAP.

Recommendation 4: The upfront payment for market suspension compensation should be the greater of the MSPS and the upfront directions payment (calculated as the VWAP). This removes the current benchmarking approach used for upfront compensation in the market suspension compensation framework.

We support this recommendation.

Recommendation 5: All compensation claims should be lodged with AEMO. This is a change from the current arrangements where claims for administered pricing compensation are submitted to the AEMC and AEMO.

We support this recommendation. 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 compensation frameworks.

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

We support this recommendation. We consider the assessment of compensation claims should be consistent and streamlined across all three frameworks. This will support agnostic/objective generator decision making towards the framework used.

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

We support this recommendation. We consider the need for a consistent opportunity cost assessment guideline across all frameworks.

Where possible, we consider there should be greater consideration of costs which could be appropriately classified as direct costs e.g. engineering study costs associated with assessing generator wear and tear as a result of complying with directions. By more accurately capturing direct costs, the added effort and cost associated with preparing opportunity cost claims and assessing those claims is minimised.

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

We support this recommendation.

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.

We support this recommendation.

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.

We support this recommendation; however, we note that opportunity cost claims in particular are more complex partly due to the nature of the supporting evidence required. As the AEMC acknowledges, this is due to the fact that opportunity cost claims typically involve consideration of counter-factual situations where a generator could have minimised costs associated with procuring fuel (coal, gas, water, electricity for energy storage) and maximised the revenue from generating electricity at a particular time.

Consequently, we consider any new time limits should be balanced to allow market participants adequate time to provide supporting evidence for opportunity cost compensation claims.

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

We support this recommendation.

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. This is different to the current approach, where cost recovery is based on the cost recovery region for each eligibility period.

We support this recommendation.

Recommendation 13: Compensation for capacity directions should be recovered from consumers. This is different from the current approach where they are classified as directions for services other than energy or ancillary services and recovered from both generators and consumers.

We support this recommendation.

Recommendation 14: The same standards of supporting evidence should be required across all frameworks.

We support this recommendation.

If you have any queries about this submission, please contact Alifur Rahman at ARahman3@agl.com.au.

Yours sincerely,

Anton King

Acting Senior Manager

Wholesale Markets Regulation