Shell ENERGY

1 February 2024

Tom Meares
Australian Energy Market Commission
Level 15, 60 Castlereagh St
Sydney NSW 2000

Dear Mr Meares

RE: Review into electricity compensation frameworks

Shell Energy Australia Pty Ltd (Shell Energy) welcomes the opportunity to respond to the Australian Energy Market Commission's (AEMC) review into electricity compensation frameworks.

About Shell Energy in Australia

Shell Energy is Shell's renewables and energy solutions business in Australia, helping its customers to decarbonise and reduce their environmental footprint.

Shell Energy delivers business energy solutions and innovation across a portfolio of electricity, gas, environmental products and energy productivity for commercial and industrial customers, while our residential energy retailing business Powershop, acquired in 2022, serves households and small business customers in Australia.

As the second largest electricity provider to commercial and industrial businesses in Australia[1], Shell Energy offers integrated solutions and market-leading[2] customer satisfaction, built on industry expertise and personalised relationships. The company's generation assets include 662 megawatts of gas-fired peaking power stations in Western Australia and Queensland, supporting the transition to renewables, and the 120 megawatt Gangarri solar energy development in Queensland.

Shell Energy Australia Pty Ltd and its subsidiaries trade as Shell Energy, while Powershop Australia Pty Ltd trades as Powershop. Further information about Shell Energy and our operations can be found on our website here.

General comments

Shell Energy believes that this review into electricity market compensation frameworks comes at an opportune time, given the increasing use of direction in the National Electricity Market (NEM) and the events of June 2022 which are outlined in the consultation paper. A fit-for-purpose compensation regime is a necessity for the NEM to function smoothly, especially at times of market stress.

As an introductory comment, Shell Energy considers that the June 2022 market events were to a great extent a result of two features. The first is that the Administered Price Cap (APC) of $300/MWh was far below what was needed in the market given the prevailing commodity prices. In our view, this drove much of the behaviour seen

[1] By load, based on Shell Energy analysis of publicly available data.

[2] Utility Market Intelligence (UMI) survey of large commercial and industrial electricity customers of major electricity retailers, including ERM Power (now known as Shell Energy) by independent research company NTF Group in 2011-2021.

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in the market at the time. The $300/MWh APC was misaligned with the APC in gas markets of $40/GJ, which translates to a generation cost of around $500-550/MWh. With the APC now set at $600/MWh until 30 June 2028, Shell Energy considers that the financial incentives are now better aligned in such a way to ensure that generators will continue to make generation available in the market during an administered pricing period (APP).

The second key point is that we have identified flaws with the operation of the Fast Start Inflexibility Profile (FSIP) which in our view contributed to some of the outcomes during June 2022. We have included a detailed description of these issues and outcomes in Appendix A. While not directly related to the issue of compensation frameworks, this issue serves as context for both our comments, the interpretation of generators' behaviour during June 2022, and how this shapes Shell Energy's policy positions on the compensation frameworks.

Objectives

Shell Energy considers that the objective of each of the three market compensation frameworks that form part of this review remains relevant and appropriate. However, given what each of them seeks to achieve, we argue that a single objective across all three frameworks would be appropriate. Ultimately the purpose of all three frameworks is to maintain the incentives for generators to make supply available in the market during times of market stress.

We recognise that the directions framework operates slightly differently in that directions can be used to maintain system security, reliable supply to consumers, or to provide currently unpriced essential system services, rather than purely to incentivise supply of energy. However, directions are used to bring supply 'unavailable' to the market due to various reasons, including spot price below cost of production, at times when it would preferably be available and operating.

Shell Energy disputes the AEMC's framing that there is a perverse incentive to be directed. Rather, we see that there can actually be perverse incentives to remaining available in the market. Primarily, this is due to clause 3.9.7(b) of the National Electricity Rules (NER) which states that a generator that is constrained-on is not entitled to receive any compensation due to its spot price being less than its dispatch offer price. Consequently, a generator concerned it will be constrained on, is likely to choose to bid as unavailable to avoid being constrained-on and potentially running at a loss. If it is then directed to operate, it can receive compensation for its costs. Modifying this clause to allow for compensation for participants dispatched for essential system services, or other reasons, to receive compensation, would severely reduce the need for directions for essential system services as well as the provision of energy and FCAS to electrical sub-regions subject to network outages.

Shell Energy strongly argues that changing this clause to allow generators constrained on to receive compensation would largely eliminate the problem of generators being left with no other choice than to bid as unavailable. We consider that amendments to this clause could involve adding a new sub-clause to allow generators constrained on for the purposes of providing essential system services, or other specific reasons, to receive compensation for being dispatched below their dispatch offer price. Additionally, clause 3.15.7B could be altered to allow directed participants constrained on to apply for compensation for opportunity costs.

We acknowledge it is theoretically possible that some low short run marginal cost generators (SRMC) could prefer to be directed and receive the 90th percentile prices. Higher SRMC generators with fuel costs though would rather operate in the market to ensure they can defend their contracts and cover their costs. As we noted in our response to the improving security frameworks for the energy transition rule change, the 90th percentile pricing approach currently used to compensate for directions is not entirely appropriate and may over-compensate some generators while under-compensating others, leading to both inefficient compensation payments and additional compensation claims.

As noted above, we consider the fact the electricity market APC was misaligned with the gas market APC, and remained well below the cost of generation contributed to some of the outcomes the market experienced in June 2022. We also query the AEMC's assertion that generators may have preferred directions compensation over administered pricing compensation given that the 90th percentile prices for all regions were below the APC of $300/MWh.

Impact of the Fast Start Inflexibility Profile

Shell Energy has also identified that flaws in the FSIP may have contributed to generators' actions in June 2022. When dispatching fast start generating units, the NEM Dispatch Engine (NEMDE) completes two calculation passes. Firstly, a unit commitment pass and secondly the pricing pass where NEM generating unit dispatch and regional reference price (RRP) outcomes are determined for the dispatch of generators bid as fast start generators.

In the first pass the NEMDE ignores all the fast start inflexibility data provided in the bid and treats all units equally and works out the dispatch for each unit based on the offer prices and volumes in the bids. Basically, it initially works out if a unit would be dispatched only on a merit order basis. From this it calculates if a fast start unit would be dispatched. If this is the case, the NEMDE issues a Mode 1 start and synchronise dispatch instruction.

The procedure will issue a Mode 1 dispatch instruction, in accordance with bid T1 and T2 times, to all units where a dispatch target equal to or greater than 0.005 MW is calculated in the commitment pass by the NEMDE. The outcome of this approach is that if 200 fast start units were bid at the MPC, and the commitment pass determined that one unit was the marginal MW for dispatch, the NEMDE would send a Mode 1 dispatch instruction to all 200 units. This is clearly an inefficient outcome from a market costs perspective.

Having issued a Mode 1 dispatch instruction, the NEMDE will continue to re-issue the Mode 1 dispatch instruction if the T1 time has yet to be met at subsequent trading intervals even when RRP outcomes has decreased and commitment of the fast start unit would no longer occur based on the FSIP commitment pass run.

Consequently, in the case of the June 2022 market events, generators may have rebid as unavailable to avoid uneconomic dispatch or uneconomic start and ensure that there was a real requirement for fast-start plant to be committed. The fact generators were then issued a direction was a result of an inefficient FSIP rather than seeking to be directed.

Further, clause 3.8.19(g) of the NER only requires that AEMO use reasonable endeavours and not best endeavours in complying with a FSIP bid. Yet generators face strict compliance obligations for compliance with a dispatch instruction. Conceivably, AEMO could issue a dispatch instruction which did not meet a generator FSIP bid and then a generator could then be held accountable for a failure to comply with its dispatch instruction.

Remedying the FSIP would also serve to remove the perverse incentives to withdraw availability from the market which then forces AEMO to issue a direction. There is a clear omission in clause 3.8.19 where AEMO is not required to consult on and develop a FSIP methodology, or review, consult and amend the methodology at routine intervals.

The current methodology has remained largely unchanged since its initial release when the FSIP was introduced at market start. We recommend the introduction of a rules requirement for AEMO to review and amend the FSIP methodology. This should ensure that the framework can be reviewed regularly, and if necessary, any problems can be addressed.

Methodology

To the greatest extent possible, Shell Energy considers that the different compensation frameworks, including what we have proposed for constrained on generators, should have consistent approaches. This would help make generators ambivalent about whichever compensation framework is used. Given that the aim of each of them is effectively to maintain incentives for generators to remain in the market at times of market stress, there is no reason for different frameworks to have different compensation procedures. A simplified arrangement with a single compensation approach for constrained on operation, directions, administered pricing and market suspension compensation would, in Shell Energy's view, 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. We also consider a single market body should handle all claims. In our view there is little reason to have different compensation frameworks managed by different market bodies.

Shell Energy also considers that opportunity costs should be considered in all compensation frameworks. Opportunity costs exist regardless of which approach is used to bring generation into the market, whether it's 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 required to dispatch at a time when they otherwise may not be dispatched in the market based on spot prices, they are forgoing the potential revenue at a different point in time.

Additionally, we considered that a defined and consistent forward-looking approach to opportunity costs is needed. It is the inability to dispatch at a point in time forward from the point where the generator is dispatched when it would otherwise choose not to do so that is the opportunity lost to the generator. This would provide generators with confidence in terms of how compensation claims will be handled.

We note that approaches to calculating opportunity costs may need to be technology specific, as battery energy storage systems (BESS) generally operate on a daily cycle, whereas plant like hydro-electric or gas-fuelled generators can have a longer-term outlook over the proceeding weeks.

The increasing numbers of BESS operating in the NEM also highlights the importance of considering opportunity costs in compensation frameworks. While fuel costs are calculable as the average cost of charging (with a premium to cover the round-trip efficiency), the value in having BESS in the energy market is that it is intended 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.

The AEMC's proposed amendments to the directions compensation regime, set out in the Improving Security Frameworks for the Energy Transition rule change second directions paper[3] highlighted the problems in focussing predominantly on fuel costs. As the AEMC acknowledged in the second directions paper, the proposed benchmark calculation does not factor in the opportunity costs involved for energy-limited plant such as pumped hydro and BESS and also, some gas, diesel and coal fuelled plant. Excluding opportunity costs from directions compensation would create a form of discrimination, whereby thermal plant would be compensated based on a benchmark fuel cost, whereas hydro and BESS would be treated on a different basis, which would likely leave them exposed to losses. Even if an alternative approach were used for BESS and pumped hydro, it would create a different kind of technology-based discrimination.

As such, Shell Energy considers it is more appropriate to have 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 codified procedure for opportunity costs be used to compensate

[3] AEMC, Improving Security Frameworks for the Energy Transition Second Direction Paper.

all generators. As noted above, 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. Shell Energy considers the current benchmark provisions in this area are deficient leading to unnecessary and time-consuming claims for additional compensation.

AER's proposed amendments

In the AER's report on the June 2022 market events, the AER made several suggestions for reforms to further safeguard reliability and system security at times of system stress. The AEMC asks for comments on the proposed reforms in the consultation paper.

The first proposal is to remove commercial considerations from the list of reasonable causes for causing a direction in clause 4.8.9(c2). In the AER's view the existence of the compensation frameworks means that a generator should not be exposed to running at a loss during an administered pricing market suspension period. Clause 4.8.9(c2) reads:

> *A Market Participant must not by any act or omission, whether intentionally or recklessly, cause or significantly contribute to the circumstances causing a direction to be issued, without reasonable cause.*

As there is no "list" of what constitutes a reasonable cause, we presume that, based on the AER's report, this could be achieved by explicitly excluding commercial considerations as a reasonable cause. Yet, directions are not only used during periods of market suspension or administered pricing.

As we have outlined earlier in this submission, generators are incentivised to bid unavailable to avoid being constrained on and running at a loss at certain times due to clause 3.9.7(b) of the NER. Commercial consideration should very much be considered reasonable under these circumstances. Amending clause 3.9.7(b) to allow for compensation when generators are constrained on, would largely negate the need for generators to bid as unavailable to ensure they are not forced to run at a loss. The proposed amendments to clause 4.8.9(c2) would then be unnecessary.

Further, the events of June 2022 were complex and involved a number of competing dynamics, including an inadequate APC (which has since been resolved) and distortions arising from operationalising the FSIP. Fixing the distortions that exist in the FSIP would also resolve some of the issues that may have caused generators to bid as unavailable at times.

The second proposal is to introduce a positive obligation on physically available generators to continue to offer capacity into the market during declared actual LOR2 or LOR3 conditions during an APP. This appears to be a reasonable change. Shell Energy considers that draft wording of any rule change would be needed to allow participants to properly assess the impacts of any new obligations. Reforms in this area should also be accompanied by changes to the FSIP as well as amendments to provide compensation when constrained on. Both situations lead to incentives to remove availability to manage inefficient dispatch outcomes during an APP event.

Finally, the AER proposes introducing an obligation for generators to use available price bands during APPs. The AER justified this recommendation by pointing to generator behaviour during the June 2022 APP when some generators bid their capacity at the MPC. In Shell Energy's view, the AEMC must recognise the commercial realities that drove some generators to do so. As the APC was set at $300/MWh and the usual strike price for caps was also $300/MWh, a generator that had sold cap contracts would have had no need to ensure it was dispatched in the spot market as it would not have faced a payout for its cap contracts. Therefore, there was no commercial need for them to generate during an APC, and as such, capacity is bid at the MPC to ensure that it only generates when absolutely necessary.

Changing the rules to require generators to use all available price bands would impose an obligation on generators to bid in ways that are not required at other times and are unnecessary for reliability purposes. In practical terms, we consider that generators are likely to respond in ways the market bodies may not expect. In all likelihood, we predict that making this change would not improve AEMO's ability to dispatch generation during an APP and would impose an obligation on generators while providing no benefit to the market.

Governance and overlapping compensation claims

Shell Energy considers that another advantage of a consistent approach to compensation is that it should remove the issues arising from overlapping compensation periods that currently occur between directions, market suspension and administered pricing periods. This would avoid the kinds of issues raised in the consultation paper where multiple compensation streams may be possible over a single time period.

On the other issue raised around timeframes for supporting information, Shell Energy understands that there may be a need to establish defined timeframes for supplying the appropriate market body with opportunity cost claims, or supporting information. To the greatest extent possible this should be set out in the NER to allow for rule changes in the future. Any requirements on timeframes should also be accompanied by defined requirements for the level of evidence required to substantiate claims.

In terms of timeframes, Shell Energy recommends erring on the side of caution and providing a longer period (e.g. 120 days) as in the immediate aftermath of market stress events like those experienced in June 2022, there can be multiple requests for information from other bodies such as the AER and staff are generally busy dealing with the market events themselves along with other information requests.

Similarly, the level of evidence required to substantiate claims needs to be sufficiently rigorous to ensure they are genuine costs but not so onerous as to create difficulties in supplying the information or used to rule out claims when genuine costs are incurred.

Based on the June 2022 market events, Shell Energy also considers there are areas of the Rules that would benefit from improved clarity. Clause 3.14.5(c)(1) implies that an administered pricing period continues to apply during a period of market suspension. We support that this should be the case and the rules should explicitly indicate this.

We also consider the Rules for cumulative price threshold (CPT) calculation purposes should indicate what price – the region original price or the regional reference price (RRP) – should apply to the CPT calculation during a period of market suspension when the NEM dispatch engine (NEMDE) remains available and in operation for *dispatch*. Shell Energy also considers that improvements to 3.14.3(a)(3) are warranted to more clearly define the circumstances where the market may be suspended due to operational difficulties.

Lastly, we consider that Clause 3.14.3(b) could be improved by the addition of wording "AEMO has declared an administered pricing period in accordance with Clause 3.14.2".

Conclusion

Shell Energy is grateful for the opportunity to comment on the status of the electricity market compensation frameworks. This review comes at an opportune time given the June 2022 market events and associated claims for compensation.

We consider that there are a number of reforms that could be made that would improve the overall operation of the compensation frameworks under consideration in this review. We recommend that the directions, administered pricing and market suspension frameworks be aligned to ensure that all three operate and compensate participants in much the same way. This should include compensation for opportunity costs.

Additionally, amending clause 3.9.7(b) of the NER to provide compensation for being constrained on as well as AEMO's FSIP procedures would go a long way to removing some of the distortions in the market that create perverse incentives to remove availability from the market.

Finally, we do not support the AER's recommendations to exclude commercial considerations as a reasonable cause to cause a direction or to require generators to use all price bands during an APP. However, we would welcome more opportunity to comment on a proposal to introduce a positive obligation on generators to continue to offer available capacity into the market during actual LOR2 or LOR3 conditions during an APP pending the release of draft rules or procedures. These reforms should be complemented by changes to the FSIP as well as amendments to provide compensation to generators when constrained on.

For more detail on this submission, please contact Ben Pryor, Regulatory Affairs Policy Adviser (0437 305 547 or ben.pryor@shellenergy.com.au).

Yours sincerely

[signed]

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