



2 October 2026

RE: Industry-led Electricity Contract Co-Design Consultation Paper

Shell Energy welcomes the opportunity to provide feedback on the co-design group's proposals.

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 one of the largest electricity providers to commercial and industrial businesses in Australia, Shell Energy offers integrated solutions and market-leading customer satisfaction, built on industry expertise and personalised service. 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 also operates the 60MW Riverina Storage System 1 in NSW, as well as the 200MW Rangebank Storage System and 370MW Koorangie Storage System both located in Victoria.

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](#).

Key Points

- Shell Energy supports the co-design objective, but the products should allocate risk to the parties best placed to manage it and avoid unnecessary costs for consumers.
- The regional reference PPA should remain firm to the Market Price Cap unless there is clear evidence that a \$600/MWh cap provides a net benefit to the NEM and would result in lower costs to consumers.
- Negative price treatment should support efficient dispatch: the regional reference PPA product should be firm only to \$0, with any negative-price option favouring a volume knock-out.
- The shaping product should be simpler and more flexible; averaging periods can reduce seller risk while preserving buyer exposure to the value of shifting energy.
- Centrally fixed charge and discharge periods may create edge effects and gaming risks; contract holders should be able to nominate periods under transparent common rules.
- Aligning a firming cap strike with the Administered Price Cap could weaken incentives to generate during administered pricing periods and should be further tested.
- The contracts should remain enforceable financial products, with no additional force majeure relief or pooled insurance that socialises project-specific risks.
- The products should not be recycled through the MMO by the FME; transparent quarterly or six-monthly auctions would better support liquidity and price discovery.
- The Working Group should test whether the products are genuinely useful to retailers and large users, including under churn, changing load shapes, rooftop PV and electrification.



Bulk Energy: Regional Reference PPA

Question 1: Is the product structure suitable for all potential sellers of bulk energy services? If not, what changes should be made?

The structure as proposed is designed primarily for weather-dependent intermittent renewable generation and has not been shown to accommodate all potential bulk-energy technologies. The Working Group should test alternative index granularity and clarify whether settlements are referenced to the Regional Reference Node. If settled at the RRN, the transfer of marginal loss factor risk to the buyer should be explicit. This risk arises because the contract settlement price and contract volume may be based on the regional reference price and energy at the regional reference node, while the seller's physical generation and the regional reference trace is affected by the various project's own marginal loss factor at their respective connection point.

Question 2: Do you support applying a \$600/MWh cap to the floating price under the Regional Reference PPA? Why or why not?

No. The cap transfers high-price risk from the seller to the buyer by limiting the buyer's hedge protection above \$600/MWh. Where spot prices exceed the cap, the buyer would need to manage that residual exposure, including through additional cap or firming cover, even where the renewable resource continues to generate and benefit from high prices. Sellers may also need firming through additional caps where their own output does not align with the regional reference profile used for settlement, however, this risk historically resides with all sellers of contracts. The design should make clear whether any requirement to procure buyer-side cover sits with the buyer, the ESEM Administrator or is otherwise socialised to consumers. From a market efficiency perspective, we consider sellers are best placed to align firming with their resource risk. The product should remain firm to the Market Price Cap unless evidence demonstrates a net benefit. Otherwise, the design risks over-procurement of firming and higher consumer costs.

Question 3: Which proposed treatment of negative prices is preferred, and why?

The product should be firm only to \$0, consistent with established treatment of intermittent renewable PPAs, to promote efficient dispatch and pricing. If the two options in the paper are retained, a volume knock-out is preferable to preserving settlement volumes during negative-price intervals.

Question 4: Do you support the proposed Reference Production Index framework? What changes or safeguards are required?

The index framework is not unreasonable and, absent the \$600/MWh cap, could reasonably balance buyer and seller interests. The methodology should be transparent, reproducible and stable, with prospective governance for fleet changes, outages, constraints, curtailment, marginal loss factors, negative prices and data revisions.

Shaping: Dynamic Time of Day Block Spread Swap

Shell Energy notes that the proposed product is complex and may be hard to value from a buyer's perspective over a long period. This may limit liquidity and resale value for the ESEMA and FME as the need to recycle the product arises.

Alternative shaping design

Shell Energy remains supportive of a simpler shaping product settled on the price in the highest and lowest-priced X intervals over a defined period. A weekly averaging approach would help preserve exposure to the



value of shifting energy while reducing seller risk associated with daily forecasting, nomination error and short-term price volatility. Longer averaging windows would further reduce risk. We consider that this provides a more workable balance between buyer hedge value and seller manageability than a more complex daily nomination framework. Valuation remains complex but is less so than the proposed instrument and this approach also avoids the issues of gaming and edge dynamics noted below.

Question 5: Do you support using forecast residual demand to determine the charge and discharge periods? And Question 6: Do you support using AEMO forecasts for this purpose, and what governance or fallback arrangements are required?

Shell Energy does not support a centrally determined nomination process that fixes charge and discharge periods without sufficient regard to contract holder needs. Pre-determined time periods may create edge effects around the start and end of each block, including incentives to shift behaviour into adjacent intervals or to optimise against the methodology rather than the underlying system need. These risks are greater where the nomination rules are predictable and common across participants.

A preferable model for this type of approach would allow contract holders to nominate the relevant charge and discharge periods for their own positions, potentially through a standardised central platform or mechanism that preserves transparency, verification and common governance. This would better align the hedge with portfolio and customer risks while avoiding a design in which a central methodology effectively determines how all contract holders manage shaping exposure.

The residual demand calculation approach proposed by the co-design group exposes users to forecast and methodology-change risk. The Working Group should publish multi-year back-testing and a transparent fallback.

Question 7: Do you support nominating the charge and discharge periods by 4:00 pm on the preceding day? Why or why not?

Shell Energy supports nomination timing that balances proximity to actual dispatch and the practical needs of operations staff coordinating various assets and contracts. We note that 4:00 pm may be too late for some staffing, fuel, nomination or trading processes and too early to incorporate later information. If data is corrected, arrives late or is unavailable, the rules for correcting or replacing nominations should be clear, automatic and capable of being checked by participants.

Question 8: Do you support the proposed daily shaping period from 9:05 am to 9:00 am? Why or why not?

No. The 9:05 am to 9:00 am period should not be adopted. The standard NEM trading day of 4:05 am to 4:00 am should be retained unless a compelling case is demonstrated. The design must also address daylight saving, missing or duplicated intervals and public holidays.

Firming: \$600 Cap

Question 9: Do you support the proposed \$600/MWh cap rather than a \$300/MWh cap? Why or why not?

Shell Energy is generally supportive of using cap contracts to procure firming capacity. However a significant issue is that aligning the strike with the Administered Price Cap may remove the seller's financial incentive to continue generating once administered pricing applies. If the contract settles at the same level as the administered cap, then during an administered pricing period the seller may be financially indifferent to whether it continues to generate or even remain available to generate during those periods. This could weaken market-based incentives for availability at times of system stress and increase reliance on clause 4.8.9 directions or other intervention mechanisms to secure generation when it is most needed.



Common Contract Features

Question 10: Do you support weekly settlement aligned with AEMO's settlement calendar? Why or why not?

Weekly settlement aligned with AEMO's calendar is reasonable in principle. Final terms should address revisions, disputes, collateral, netting, tax and interaction with market settlement.

Question 11: Should the contracts include additional force majeure relief or pooled insurance arrangements? Why or why not?

No additional force majeure relief should be included. Sellers should manage their exposure by deciding how much capacity to sell and maintaining an adequate risk-management framework. Pooled insurance would socialise project-specific risks and increase costs to consumers. Financial contracts should remain enforceable through outages, with transparent market-priced buy-back arrangements where available.

MMO and Buyer Usefulness

Question 12: Do the proposed contracts satisfy the Working Group's Terms of Reference and assessment criteria? Why or why not?

The products may satisfy the Terms of Reference, but the more fundamental issue is whether those Terms allocate risks efficiently. The design seeks to transfer risks historically managed by sellers to buyers and potentially consumers. They appear best suited to support only intermittent renewables and batteries, and may depend on integration with other contracts to support efficient risk management in the market. Further quantitative testing should be conducted.

Question 13: Are the proposed contracts suitable for application under a future Market Making Obligation? Why or why not?

The products are not inherently unsuitable for an MMO. However, the FME should not be allowed to dispose of inventory through the MMO framework. Recycling should be limited to transparent quarterly or six-monthly auctions. The MMO design must also address who will naturally sell conventional swaps, peaks and other hedges after coal closure, the fallback if natural sellers disappear, and the risk of MMO expansion to other contract forms.

Question 14: Will the proposed contracts be effective for retailers and large energy users to manage their financial and load-following risks? Why or why not?

The products do not presently appear sufficient for retailers and large users to manage financial and load-following risks. Integration with other fungible contracts may improve this but then increase costs passed to consumers. The Working Group should identify natural sellers of complementary products after coal closure, specify a liquidity fallback and test churn, acquisition, changing load shapes, rooftop PV and electrification. Positions must be divisible, transferable and readily rebalanced.

Shell Energy welcomes further engagement. If you have any questions or would like further details relating to this submission, please contact Peter Wormald at peter.wormald@shellenergy.com.au

Yours sincerely,

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