Hybrid Generation LTESA consultation feedback summary

Overview

This document summarises the key themes of market feedback ASL received during the Hybrid Generation LTESA consultation in early 2026.

Over the 4-week consultation period, ASL participated in 20 different stakeholder meetings to provide briefings and receive feedback. Stakeholders comprised of industry groups, government partners, market bodies, investors and developers, and domestic and international banks. ASL received 21 different written submissions.

Need for a Hybrid Generation LTESA

The majority of stakeholders expressed a clear and consistent preference for a purpose-built Hybrid Generation LTESA, rather than relying on incremental modifications to the existing Generation LTESA. While some responses acknowledged changes to the current Generation LTESA could provide marginal improvements, the prevailing view was that these would not address the fundamentally different operating and revenue characteristics compared to standalone generation.

Stakeholders widely agreed that hybrid projects differ materially in how they dispatch, manage risk and earn revenue. The need to account for the true economic value of energy shifting and firmed renewable output was highlighted. Some submissions noted that the existing Generation LTESA, designed primarily for standalone renewable generation, and capable of supporting hybrid projects through ringfencing arrangements, struggles to accommodate these characteristics, treating generation and storage as separate assets rather than single coordinated unit. It was highlighted that adapting the existing Generation LTESA has led to increasing contractual complexity, including sub-metering and apportionment mechanisms that attempt to approximate hybrid behaviour.

A recurring theme was the importance of early-stage revenue support. It was noted that an LTESA designed specifically for hybrid projects could materially reduce merchant risk, lower cost of capital and improve lenders' ability to assess revenue certainty across integrated assets. Several respondents also highlighted the LTESA acts as a catalyst for private offtakes rather than crowding them out, particularly in a market where hybrid offtake structures are still evolving. There was also strong demand from the market for wind projects to be able to bid for this product.

The feedback received indicated strong support for a dedicated Hybrid Generation LTESA as the most effective way to overcome investment barriers, reduce financing costs and align contractual design with the operational realities of hybrid projects.

Project configuration

ASL asked for feedback on its initial position, requiring projects to be DC-coupled with a single DUID. In response, stakeholders shared concerns that mandating this configuration would reduce operational flexibility, increase compliance exposure, and could result in conservative bidding behaviour.

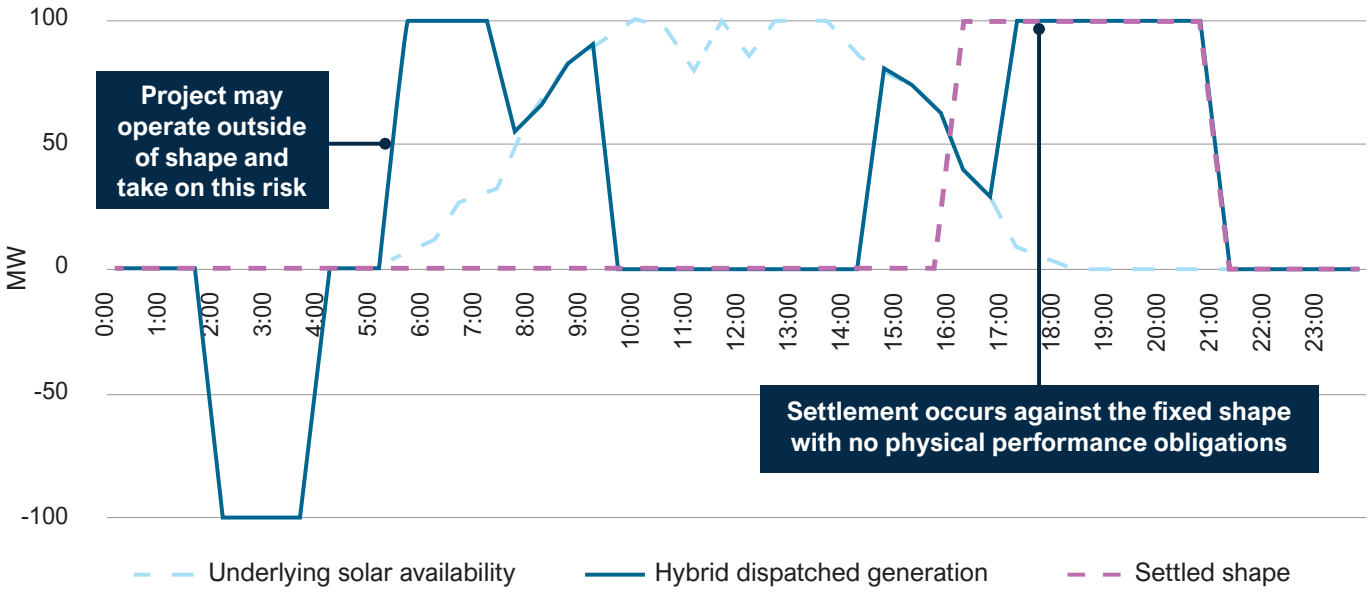
Responses emphasised that a Hybrid Generation LTESA should explicitly accommodate both AC- and DC-coupled hybrids to maximise participation and innovation. It was also noted eligibility should be technology-neutral and outcome-based, focussing on performance at the point of connection rather than internal configuration.

There was also strong support for allowing multiple DUIDs behind a single connection point, with settlement based on aggregated net exports. This was seen as better reflecting arrangements within the National Electricity Market (NEM) and how hybrid projects are being developed in practice.

Preferred option

While stakeholders indicated that both options could be workable, **Option 2 – generation-following with price risk share** received stronger support. Stakeholders preferred Option 2 based on it providing a stronger foundation for supporting efficient, lower cost of capital investment in hybrid projects in NSW. It was noted that Option 2 would better preserve incentives to respond to market signals and thus could better suit the emerging hybrid market.

Option 1



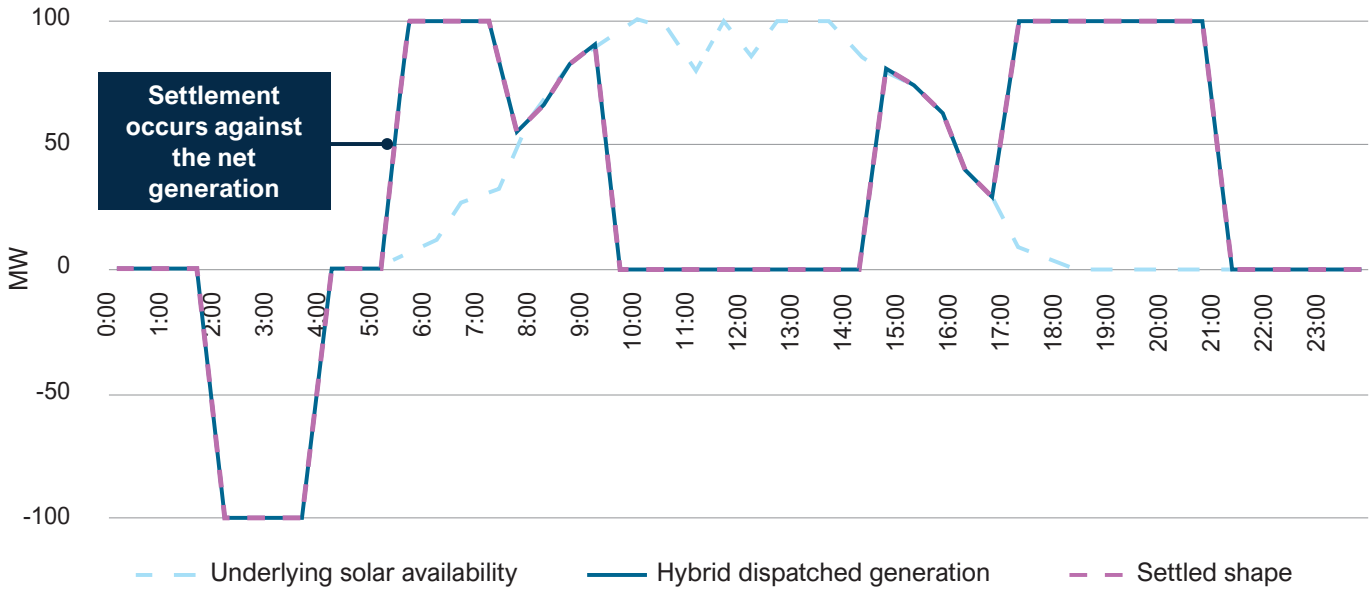
Option 1 – fixed-shape fixed-volume was considered viable but not universally preferred. It was seen to align well with existing contract-market products, and several stakeholders noted this alignment could lower transaction costs, improving hedgeability, and support broader forward-contract market liquidity.

However, responses consistently raised concerns regarding risk and impact on financing costs. Option 1 was seen to expose projects to shape and volume risk arising from resource variability, unplanned outages, degradation and evolving curtailment patterns. As a result, it was viewed as likely to lead to higher financing costs compared with Option 2 and to favour proponents with strong internal trading capability and a portfolio of existing assets. Responses also cautioned that fixed contractual shapes may become misaligned with future price patterns as the power system evolves.

Feedback on annual payment caps was mixed but generally supportive of retaining a cap as a risk-management tool. A symmetrical absolute annual cap was seen as simple and offering consumer protection, allowing proponents to have certainty around worst-case outcomes. Some respondents noted an alternative cap mechanism, such as $300/MWh cap instead of total annual payments could be simpler to evaluate whilst providing the same consumer protections.

Whilst stakeholders generally supported the proposed shift towards standardised contracts in line with the National Electricity Markets wholesale market settings review (NEM Review) recommendations, overall, Option 1 was viewed as less flexible and less aligned with hybrid operating realities than Option 2.

Option 2



Option 2 – export-following with price risk share received strong and broad support, with most responses identifying it as the preferred structure and the most appropriate foundation for supporting efficient, bankable investment in hybrid projects.

This option was consistently viewed as well aligned with how hybrid projects operate in practice, with settlement against net exports reflecting actual dispatch and physical performance across generation and storage components. Responses highlighted the structure still preserves incentives to respond to market price signals, supports energy shifting, and avoids locking projects into fixed shapes that may become inefficient as the system evolves.

Respondents supported the principle of sharing upside and downside risk, however many emphasised the 50:50 price risk share as being insufficient to encourage investment without further refinement. The 50% downside protection was seen as limiting debt capacity, increasing financing costs, and potentially resulting in inflated bid prices. An asymmetrical price-risk share structure with greater downside protection was the preferred method, with favourable responses regarding an 80% downside protection in intervals where fixed price exceeds spot and net exports are positive. It was also suggested that proponents could bid their preferred risk-share percentage within a defined band. Several arguments also noted that symmetrical caps, when combined with symmetrical risk sharing may increase strike prices and reduce competitiveness. Alternative mechanisms suggested including capping swap settlements rather than total annual payments. A smaller number of respondents expressed views that the cap could work as proposed or that changes to the cap structure may have limited impact overall.

Overall, Option 2 was seen to better align with the operational realities of hybrid projects, financing requirements, and evolving market conditions.

Financing

Engagement with financiers and banks highlighted that Option 2 is more likely to achieve lower financing costs than Option 1, provided price risk sharing parameters and annual payment caps are appropriately calibrated. Maintaining a clear linkage between contract settlement and physical output was noted as improving revenue certainty, reducing basis and volume risk, and better supporting debt sizing.

Whilst some residual merchant risk remains with Option 2, many considered this acceptable and preferable to the shape and volume risks embedded in Option 1, particularly if a project was not available to defend the shape in the event of major price spikes.

What's next

ASL will recommence tenders for Generation LTESAs in Q2 2026. In advance of the Q2 2026 tender, ASL will release the final Hybrid Generation LTESA and Project Development Agreement (PDA), considering the feedback received in this consultation process.

The two generation tenders scheduled for 2026 are seeking 5 GW of generation projects. ASL expects that solar-hybrid projects could be a key contributor to these tenders and the 2030 Infrastructure Investment Objectives. ASL remains technology neutral in considering projects and is committed to supporting all forms of generation, including wind. It is expected that wind-hybrid projects would also bid for the Hybrid Generation LTESA. Standalone solar and wind will remain able to bid for the existing Generation LTESA, which can also accommodate hybrid projects depending on configurations and proponent preference.

Bidding for a Hybrid Generation LTESA

ASL is committed to only supporting projects that are in the Long-Term Financial Interests of NSW electricity customers. That is, the forecast benefits of supporting the project outweigh the forecast costs. Hybrid projects are expected to provide high forecast benefits to NSW electricity customers based on their ability to time shift energy to periods of higher demand and value.

ASL has recently released its 2026 NSW Investment Priorities, calling on projects to bid in a way that provides value to consumers and ensures projects are investable, commercially viable and deliverable.

ASL