Ms Anna Collyer
Chair
Australian Energy Market Commission
PO BOX A2449
Sydney South NSW 1235

8 April 2024

Dear Ms Collyer

Re: Retailer Reliability Obligation exemption for Scheduled Bidirectional Units

Tesla Motors Australia, Neoen and Iberdrola are jointly submitting a Rule Change request to exempt scheduled bidirectional units from being considered as liable assets under the Retailer Reliability Obligation (RRO). The Rule Change request proposes a minor amendment to the definition of RRO liable entity.

In our view this Rule change would be simple to implement and create immediate market and system benefits. It would directly address the broader operational concerns (and unintended consequences) created by applying an RRO liability to scheduled bidirectional units—specifically that it also impacts the ability of the asset to provide critical grid services on the load side of the scheduled bidirectional unit, therefore impacting system security and reliability.

We consider that appropriately exempting scheduled bidirectional units will remove both investment and operational risk overhangs, increasing the efficiency of dispatch by removing artificial limitations imposed by the RRO on the tools available to AEMO to manage system security and reliability measures, remove potential conflicts between RRO compliance and essential system service provision, and thereby ensure full value can be provided from bidirectional assets such as battery storage—supporting the National Energy Objective.

We look forward to working with the Commission to progress this proposal.

Josef Tadich
Head of Energy – Australia
Tesla

Louis de Sambucy
Chief Executive Officer
Neoen Australia

Ross Rolf
Chief Executive Officer
Iberdrola Australia

1 Context for Rule Change

The current application of the Retailer Reliability Obligation (RRO) applies a liability to all loads in market which includes grid charge from utility scale battery energy storage systems (currently registered as scheduled loads, and soon to be registered as scheduled bidirectional units (BDUs) from July-2024 when the Integrating Energy Storage Systems (IESS) Rule Change takes effect).

The current RRO liability applies in the same way to all MWh grid imports, regardless of whether those MWh are consumed by an end-use customer or stored for later export. The RRO liability also does not distinguish between consumption of energy and load that is used to provide critical grid support services, or consumption by a market participant following dispatch instructions or Directions from AEMO (e.g., charging to avoid a future unserved energy event).

It appears this was an unintended oversight in the RRO scheme design, with its objective to ensure large retailers can demonstrate financial contracts with generation supply during forecast reliability events. It is unclear what market benefits would arise by placing those same liabilities on large-scale storage assets (which can also act as a form of system security or network infrastructure) and potentially requiring equivalent demonstration of financial contracts with other generating units. In our view, this is a clear misalignment with the objectives of the RRO (to ensure reliability during forecast peak periods) adding unnecessary costs and risks to owners and operators of battery storage assets.

1.1 Problem statement

In practice, the implementation of the RRO puts Market Participants with utility scale battery storage[1] in a position where they need to choose between:

- Potentially breaching the RRO and incurring a liability for providing critical grid supporting services;
- Turning off the "charge" functionality of a utility scale battery, and effectively turning several grid supporting services off, as well as limiting the ability to recharge to provide future critical services; or
- Buying hedging contracts from exiting thermal generators to offset this potential load.

[1] **Note:** while this proposal references 'utility-scale battery storage' we recognise the RRO liabilities would only apply to storage assets consuming over 10GWh per year. However, in practice this equates to every battery system approximately 20MWh or larger – i.e. the majority of grid-scale batteries connected in the NEM today, as well as almost all projects currently planned.

This highlights the need for a far more nuanced assessment of the application of the RRO, and treatment of scheduled, bidirectional, inverter-based resources.

The full extent of the incompatibility between providing grid-supporting services and the RRO liability was not well understood and therefore underestimated at the time the IESS Rule Change was finalised. For example, there were previous views assuming that under an 'Integrated Resource Provider' registration approach, battery storage could net out any load draws against corresponding generation. However, in reality, there are still risks of timing mismatches (e.g. where batteries are directed to provide load-side system services during a RRO liability window period); and there is no consideration of round-trip efficiency impacts for larger battery systems with high frequency dispatch profiles. This creates unnecessary monitoring and management for battery operators – with negligible market benefit.

There are three aspects which should be considered in determining an appropriate application of the RRO to scheduled bidirectional units:

(1) Where scheduled BDUs happen to charge from the grid during an RRO liability window and they are doing so based on direction of AEMO;
(2) Where scheduled BDUs are charging from the grid during an RRO liability window based on AEMO dispatch but are not contributing to an LOR event (and, if prices are high, are doing so to ensure resources are available for future more critical periods); and
(3) Where scheduled BDUs are providing ancillary services or other grid supporting functions during the reliability window, they should not be prevented from doing so through the actual or potential application of a penalty. **Grid security and reliability needs should be viewed as a higher order priority than RRO compliance**.

These points were considered in depth before the creation of this rule change. Particularly in relation to the third point, the application of the initial T-1 instrument in South Australia has demonstrated that applying an RRO liability to system security services has implications that were not fully considered at the time of the IESS Rule Change—due to the implementation of new Rules since the IESS Final Determination, and additional scoping of engineering work to meet requirements. Impacted services include:

- Contingency and regulation FCAS lower services including the new 1 second very fast FCAS market;
- System integrity services, such as System Integrity Protection Schemes (SIPS) and Wide Area Protection Scheme (WAPS);
- The operation of bidirectional units set up as grid-forming inverters that will incur unavoidable liability in providing inertia or system strength; and
- Out of market contracts to provide system security services.

As the penetration of renewable energy increases, complemented by grid-forming and inverter-based resources such as batteries, the incidence of the above impacts will only continue to increase, placing additional conflict between the goals of the RRO, and broader operational challenges of transitioning to renewable energy while maintaining a low-cost, reliable and secure grid.

1.2 Rule Change Background

Initial RRO design

The inclusion of utility scale storage assets was considered by the Energy Security Board (ESB) in the initial design thinking of the National Energy Guarantee (NEG) and associated RRO. At that stage there were very few utility scale battery storage assets operating in the NEM, and it was unclear whether or how the RRO would apply.

The final Regulatory Impact Statement (RIS) on the RRO—released in December 2018—considered that a key outcome of the policy was to encourage new investment in dispatchable sources of energy generation such that the electricity system operates reliably. The RIS explicitly noted that the RRO would "[require] retailers to contract with generation, storage or demand response to incentivise dispatchable generation to be available to meet consumer and system needs."

Applying the liability to scheduled BDUs appears to be counter to the intended outcome of the RIS which was designed to drive investment in new storage assets.

IESS Rule Change

The topic of applying RRO liability specifically to the asset class of scheduled BDUs was then considered in more detail as part of the IESS Rule Change. The initial proposed AEMO position was to explicitly exempt scheduled BDUs as an asset class under the RRO. Industry strongly supported this position based on its alignment with the RIS as noted above.

The final IESS Determination considered that Integrated Resource Providers (IRPs) should be treated consistently with the load of market customers. It should be noted that at the time the IESS Rule Change was considered, the RRO was just one of many topics considered in a very detailed Rule Change process. The full extent of the impact on grid services was also not well understood by the wider industry, nor considered in detail through the IESS consultation process by the time the Rule Change was finalised (the final consideration of the matter only formed part of "Other Issues" included in an Appendix of the Final Determination). However, it was flagged as a risk to be addressed by battery storage proponents throughout the IESS consultation period, which noted the additional nuance of batteries in providing essential system services and consideration needed for round-trip efficiency losses, e.g.:

> “We hold significant concerns on the application of T/DUOS charges, reduced bidding flexibility, and unintended RRO liabilities for grid-scale storage systems. As such, we recommend progressing the FCAS changes as a matter of priority, de-coupled from other aspects of the rule change if they require more time for design or implementation”[2]

The practical impacts of RRO liabilities have only continued to be reinforced through the current RRO T-1 process in South Australia.

1.3 Post Rule Implementation – South Australia T-1 event

The first enforceable Reliability Instrument under the RRO is currently in operation in South Australia. In 2022, the AER issued a T-1 Reliability Instrument for the following period:

> “Working weekdays from 8 January to 29 February 2024 (inclusive), for the trading periods between 5 PM and 9 PM AEST.”

The T-1 instrument from South Australia has provided more insights into the issues as they arise in practice. For example, liable participants are looking at avenues to not provide load-side services (regulation or contingency FCAS lower) to avoid RRO liabilities. These services could either be bid out of market or switched off. Market hedging has not been considered an option given the uncertain nature of the services. Relatedly we note the increasingly wide periods of coverage (the expected RRO shortfall period in NSW commencing in December 2025 is for a period of 3 months for 7 hours a day).

We note that in practice, batteries are currently providing around 40% of the market share of FCAS services in SA (for the new 1s very fast FCAS market this increases to 100% batteries and demand response). All of which are considered to be liable assets under the RRO. If all captured assets are switched off from providing a 1s response during reliability periods, this raises significant system security risks. During the RRO period, South Australia could lose 100% of 1s lower capability, amounting to ~35% of total capacity registered for NEM-wide 1s raise response. Similarly, batteries may be disincentivised from providing contracted services such as Fast Frequency Response (FFR) (currently procured by ElectraNet) in favour of avoiding an RRO liability—thereby increasing the risk of system black events. Neoen’s requirement under its Wide Area Protection Scheme (WAPS) applying to Hornsdale Power Reserve may also incur an unavoidable load-side RRO liability should ElectraNet request HPR to charge. This would be the case for system strength provision for grid-forming inverters as well.

[2] Tesla submission to IESS Rule Change: https://www.aemc.gov.au/sites/default/files/documents/a19._tesla.pdf

Under a scenario where batteries opt-out from FCAS provision to avoid RRO liabilities (i.e. the remaining providers increase their share back to 100%) this would both increase costs to consumers (from an increase in NEM-wide FCAS prices) and create additional systems security risks due to the relative lower quality and slower performance of non-battery providers and the inability to value stack in the same way as batteries. This is particularly acute in the faster markets (i.e. 1s and 6s markets are dominated by battery storage, with other technologies having increased share in 60s and 5min markets), but with batteries now at ~50% of total FCAS provision NEM-wide (see further detail in Section 3 below). With AEMO projecting that all coal could be closed soon after 2030, there is a credible risk of shortfall if batteries do not participate.

Methodologies considered to comply with RRO liabilities involve physical constraints being placed on battery storage assets to avoid any form of charging during liability windows—including providing any load side system security services which is counter to the hierarchy of system security and stability in grid operations. This would need to be implemented for 'out-of-market' services such as system strength or system integrity contracts that cannot be bid out of provision – triggering additional complexities with network utilities and system operators with their own contracted compliance regimes.

Complying with the RRO also restricts the ability of energy storage units to charge over the RRO period in order to deliver future critical services, including energy to avoid load shedding. A scheduled BDU will only charge if it receives a dispatch instruction in line with its bids or it receives a direction or instruction from AEMO to charge. In both cases, charging would only proceed if AEMO (through NEMDE or instructions) determines that charging is consistent with efficient operation of the grid, which would require not contributing to unserved energy (i.e., NEMDE would not dispatch scheduled load if this would require involuntary load shedding, and AEMO would not issue directions or instructions that lead to a net increase in unserved energy). Without the ability to charge "now" to avoid unserved energy "later", the current RRO in practice can lead to *worse* reliability outcomes.

As with the grid support servicers above, market hedging (including procuring qualifying contracts) is also not generally viable to cover such charging, as charging during an RRO peak period would naturally be unlikely except during extreme circumstances. It would therefore not be economical to procure cap contracts or other bespoke contracts for those periods—noting again that charging during RRO periods would not be common. In the longer-term, such contracts would also only be available from other energy storage units, which would then in turn require further contracts—inconsistent with the least-cost pathways identified (for example) in the ISP. In aggregate, the current RRO acts as a barrier to investment in new storage, impacting medium-term reliability.

2 Proposed Rule Change

Tesla, Neoen and Iberdrola collectively consider that an efficient exemption for scheduled BDUs can be achieved with a relatively minor Rule Change.

The change proposed to the AEMC is to update the current wording of **Rule 4A.D.2(b)(2)** to add the words "or scheduled bidirectional unit" after "small generating unit". The new Rule would read as below:

> "A person who is a Market Customer or Integrated Resource provider is not a liable entity for a region: the aggregate consumption of electricity of all connection points in that region for which it is financially responsible at the end of the contract position day (excluding any market connection point for a market generating unit or small generating unit **or scheduled bidirectional unit**) is equal to or less than 10GWh per annum as determined in accordance with the Contracts and Firmness Guidelines."

We note that the above proposal is specifically targeted at battery energy storage technologies captured as scheduled bidirectional units, and the Commission may need to conduct further assessment on how other Integrated Resource Provider technologies (e.g. pumped hydro storage) may or may not continue to be captured under RRO liabilities.

3 Contribution to the National Electricity Objective

As outlined above, the current RRO framework will result in a clear barrier to investment in new battery storage while also restricting the operation of those existing battery storage assets captured under the RRO (effectively all utility-scale battery systems as noted above). This has clear cost impacts not only for battery storage operators but on all market participants (and ultimately consumers). Therefore, this rule change proposal has a direct link to supporting the National Electricity Objective (NEO) as stated in the National Electricity Law:

> *"to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to:*
> *a) price, quality, safety, reliability and security of supply of electricity; and*
> *b) the reliability, safety and security of the national electricity system; and*
> *c) the achievement of targets set by a participating jurisdiction—*
> *i. for reducing Australia's greenhouse gas emissions; or*
> *ii. that are likely to contribute to reducing Australia's greenhouse gas emissions."*

The impact of exempting batteries from the RRO is explored in further detail in the following sections.

3.1 Impact on market prices

We first note that exempting batteries from the RRO obligations will not increase RRO costs to other participants, and may actually reduce compliance costs. All retailers and large loads are already obligated to acquire sufficient Qualifying Contracts. Exempting batteries would reduce competition for, and prices of, Qualifying Contracts. It will also not negatively impact reliability as batteries are only dispatched for charging in NEMDE if it is least-cost to do so.

Conversely, as outlined above, preserving RRO liabilities for utility-scale battery systems over ~20MWh would necessitate battery operators to turn-off or bid out services from markets, conflict with out-of-market services such as system strength or SIPS, and require additional hedging contracts to be purchased to cover liabilities. Given the uncertainty of RRO liabilities, it is extremely difficult to put a price to these hedges if impacted participants even sought to purchase, which is unlikely given it would destroy the economics of providing ‘covered’ FCAS services. However, as an example and in simple terms, we note:

1. Average Lower FCAS prices in NSW in 2023 were $25/MW/hour (summed across all services); assume this price applies flat in all quarters.
2. If batteries were to hedge this load, it would likely be through purchasing caps as qualifying contracts. Forward cap prices for Q1 2025 are trading at $25-40/MWh.
3. Assuming that batteries in the future are the marginal price setter in 80% of periods (nominal assumption), the marginal price would shift by $20/MWh to [$45/MWh]

This means for every 100 MW of Lower FCAS, that would be an additional ~$20/MW/hr x 100 MW x (8760/4) = $4.4m in additional and unnecessary costs on consumers across the quarter

Overall, this creates both direct costs (market and contract revenues forgone and/or hedging contracts required) as well as indirect costs (additional monitoring and operational changes to limit exposure) for battery operators, in addition to wider market costs (higher essential system service costs, and erosion of high-performance suppliers).

3.2 (Cost-effectively) supporting reliability and security of supply

With battery storage providing an increasing value stack of services (energy, FCAS, system strength, voltage control, SIPS etc) in direct response to system needs and market price signals, quantifying these costs is highly dependent on local constraints and the corresponding response from alternative providers (e.g. high-cost gas plants). However, the macro impact is clear and well documented – improving the investment and operating environment for battery storage (i.e. by removing RRO liabilities and allowing these assets to operate unhindered) unlocks the flexibility and fast response of battery systems in the bid stack, which in turn:

a. increases competition for all participants,
b. puts downward pressure on market prices,
c. increases system security and reliability of supply,
d. enables higher penetration of renewables, and therefore
e. accelerates the reduction of electricity emissions

In other words, every limb of the NEO is positively impacted.

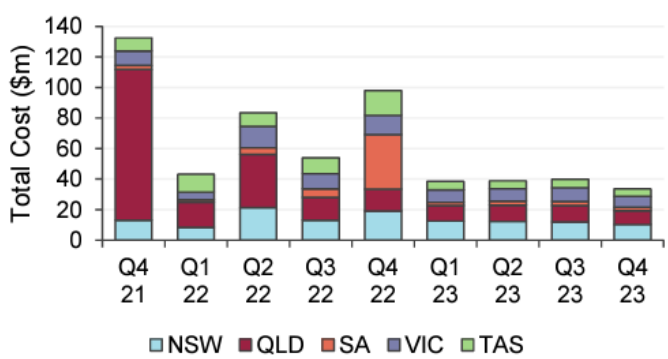
These benefits are recognised and reinforced by the AER in its recent 'Wholesale electricity market performance report'[3]:

- *"This makes them [batteries] more flexible and responsive. Importantly, the efficiencies inherent in these technologies, such as lower marginal cost to operate and lower capital costs, allowed them to offer at mostly low prices. As a result, over the past 2 years they were dispatched for the majority of what they offered. This encouraged some incumbent participants, such as black coal generators, to shift capacity to lower prices to compete when it was economical to do so....*
- *Over the last 2 years we have generally seen improvements to the level competition in FCAS markets, as they have continued to attract new entrants and expansions from established participants."*

Following the uptake of battery storage at utility scale, this has led to real cost savings in the market. For example, a general declining cost trend is shown in AEMO's latest Quarterly Energy Dynamics Q4 2023[4], where lower FCAS prices are correlated with an increasing uptake of battery storage in the NEM:

Figure 65 FCAS costs slightly lower than previous quarters, but significantly reduced from Q4 2022

Quarterly FCAS costs by region



---

[3] www.aer.gov.au/system/files/Wholesale%20electricity%20market%20performance%20report%20-%20December%202022_0.pdf

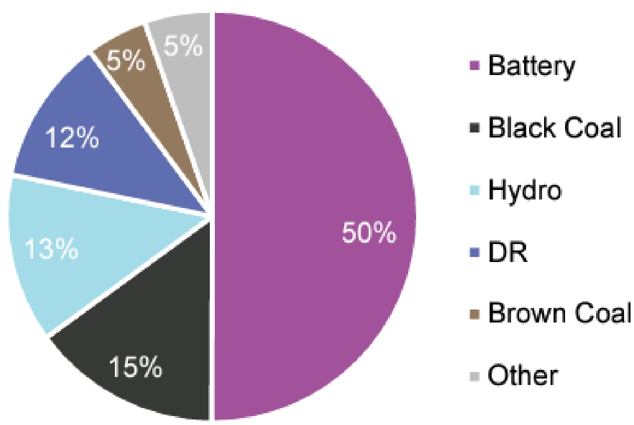
[4] https://aemo.com.au/-/media/files/major-publications/qed/2023/quarterly-energy-dynamics-q4-2023.pdf?la=en&hash=9E82966D60F4FA5050F1AF1109D5F158

With AEMO noting:

- *"Batteries continued to be the dominant technology providing FCAS, with a market share of 50% (Figure 68), increasing from their 40% volume share in Q3 2023 and 38% in Q4 2022. This increase was driven by both the new very fast FCAS service and from construction and full commissioning of new batteries, with growth since Q3 2023 led by increased provision from Hazelwood (+163 MW), Riverina (+125 MW) and Torrens Island (+84 MW)"*

Figure 68 Batteries further grew FCAS market share

FCAS volume market share by technology – Q4 2023



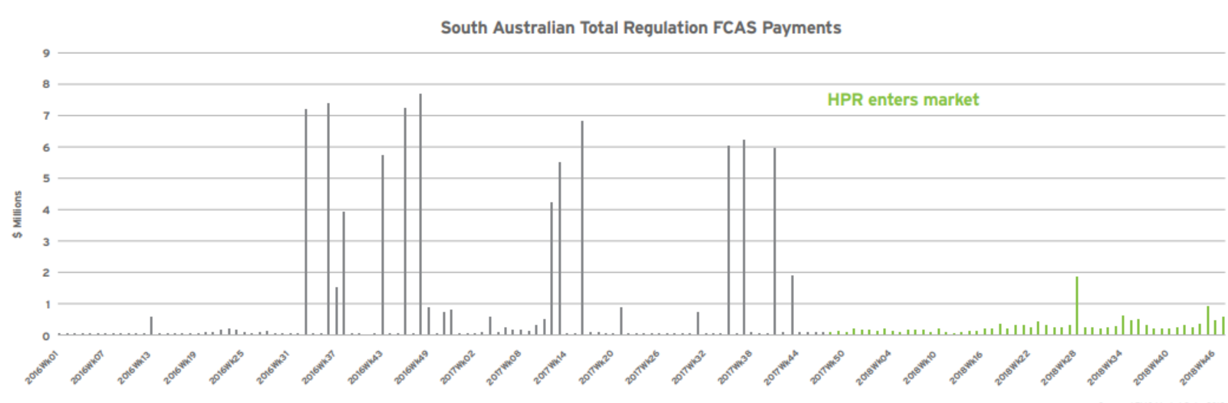
The benefit of batteries is analysed further in two independent reports from Aurecon looking at the impacts Hornsdale Power Reserve (HPR) had in its first 2 years of operation, following its entry into the NEM in late 2017. Key findings include:

- *The introduction of the HPR has contributed to removing the need for a 35 MW local FCAS minimum constraint – estimated to have added nearly AUD 40 million in Regulation FCAS costs in both 2016 and 2017.*
- *HPR commenced operation towards the end of 2017 and during Q1 2018, it captured nearly 10% of the raise FCAS market in the NEM, displacing higher priced (predominantly coal) supply.*
- *During Q4 2017, the constraint bound for 20 hours resulting in approximately AUD 8 million of additional FCAS costs whereas during Q1 2018 it bound for 13 hours without significant cost impact due in part to HPR's contribution to the South Australian FCAS market.*
- *Additional dispatchable and flexible generation would provide further reliability of supply and competition during peak demand and energy price periods.*

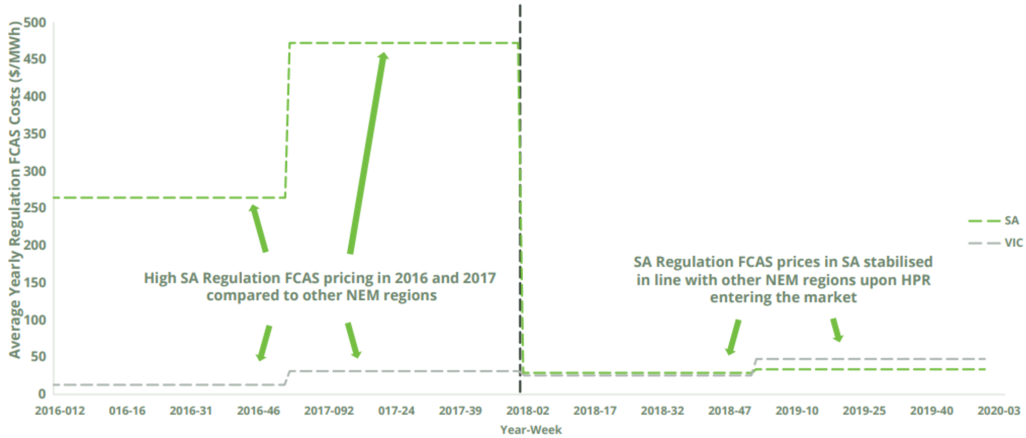
Over its second year, in 2019 Aurecon found[5]:

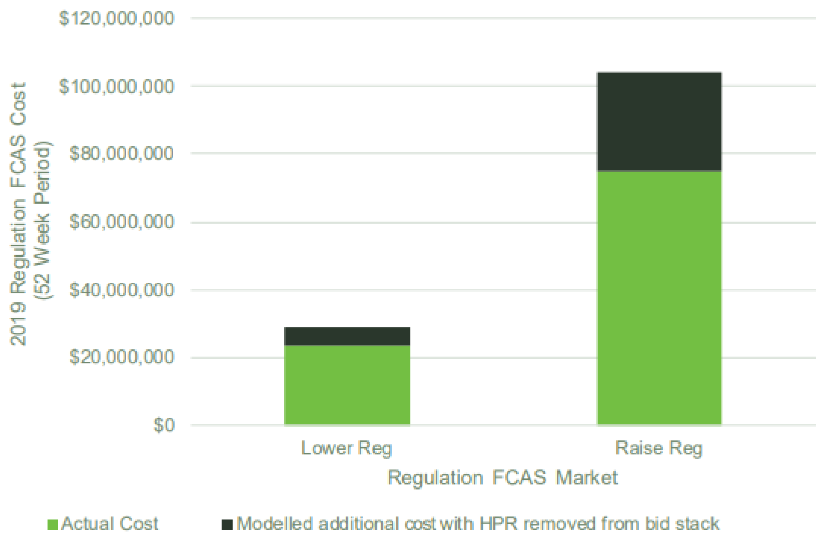
- *HPR captured approximately 15% of the Contingency FCAS market volume and 12% of the Regulation FCAS market volume across the mainland NEM regions.*
- *HPR is modelled to have reduced the total Contingency FCAS cost by approximately $80M, and the total Regulation FCAS cost by approximately $36M, for a total NEM cost reduction of approximately $116M.*
- *Approximately $102M of these cost reductions (88%) were during periods when South Australia was interconnected with other NEM regions.*
- *HPR's market value was also particularly evident during a 5-hour South Australia separation event on 16 November 2019, in which it is modelled to have provided a market benefit of approximately $14M.*
- *Upon the introduction of HPR into the FCAS markets, average yearly regulation FCAS costs from South Australian generators fell from a high of $470/MWh to less than $40/MWh, where they remain today, resulting in considerable savings in South Australian energy costs.*
- *HPR has provided a high portion of the total procured Lower Contingency FCAS services on the NEM in 2019. It has put considerable downward pressure on prices, especially in the Lower 6 second FCAS market.*
- *HPR has responded to three South Australian separation events since entering service. On each occasion it has supported system security for the South Australian network by responding with its Fast Frequency Response capability to reduce the severity of the disturbance and support a return to normal frequency conditions.*

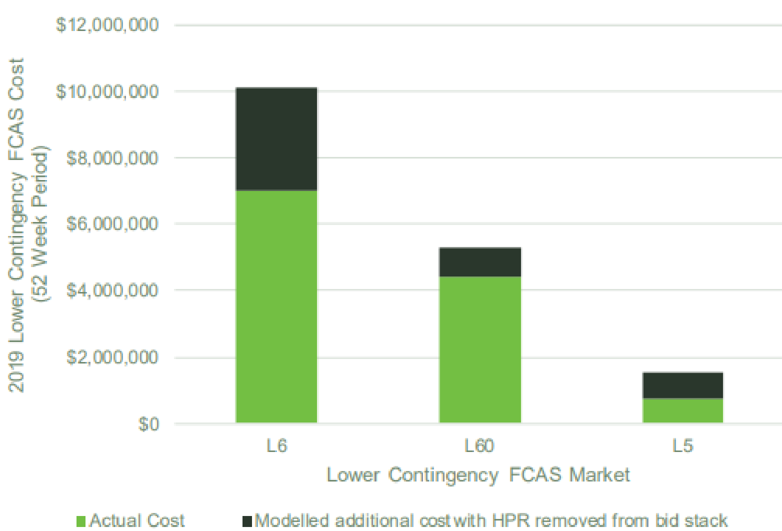
Figures from Aurecon HPR Reports demonstrating the above findings:



5 https://www.aurecongroup.com/projects/energy/hornsdale-power-reserve


Average Yearly Regulation FCAS Costs ($/MWh)
High SA Regulation FCAS pricing in 2016 and 2017 compared to other NEM regions
SA Regulation FCAS prices in SA stabilised in line with other NEM regions upon HPR entering the market
SA
VIC
Year-Week


2019 Regulation FCAS Cost (52 Week Period)
Lower Reg
Raise Reg
Regulation FCAS Market
Actual Cost
Modelled additional cost with HPR removed from bid stack


2019 Lower Contingency FCAS Cost (52 Week Period)
L6
L60
L5
Lower Contingency FCAS Market
Actual Cost
Modelled additional cost with HPR removed from bid stack

Whilst the Aurecon study focused on the operations of HPR, these benefits and impacts can be generalised to all utility-scale batteries now providing equivalent services across all NEM regions, recognising different market dynamics and competitive pressures will inevitably change actual costs and benefits, as the generation mix and local constraints change over time.

3.3 Implementation Costs vs Benefits

There would be some administrative costs to enact and then implement RRO exemptions for scheduled bi-directional units (to which we seek AEMC guidance on quantification) but we do not expect these to be significant and in practice would be more than outweighed by the savings realised from other policy mechanisms seeking to incentivise more storage into the NEM. For example, removing barriers to battery storage aligns with targets set by states and Federal Government's overarching goal to reach 82% renewable energy, and would specifically benefit the Capacity Investment Scheme seeking to contract an additional 9GW of dispatchable capacity (i.e. scheduled bi-directional units such as battery storage). Removing the risk of RRO liabilities would allow proponents to lower their expected government incentives.

4 Considerations of Technology Neutrality

We note one of the Commission's justifications to include battery storage in the RRO was based on the principle of technology neutrality. Whilst we agree with this as a design principle, we note that battery storage has no equivalence to typical end-customer load under the intent of the RRO, based on the following:

- Unique Operating Characteristics - Scheduled battery storage assets are not equivalent to an 'end-customer' loads but have more equivalence to a generator in respect to any peak demand or network usage impacts. A scheduled battery asset is not typical end-customer load (which may add to peak requirements), but is highly controllable, subject to AEMO dispatch control, with millisecond two-way response, providing a suite of network benefits from both energy and non-energy services. Many services are still unvalued, and battery operators bear the costs (and energy losses) in providing these wider system benefits. They should not also have to bear additional RRO liabilities.
- Generator Neutrality - Imposing RRO liabilities would disadvantage battery assets relative to other generators who are exempt. Suggesting RRO liabilities are a technology neutral application based on only load-side services ignores the exemption granted to auxiliary load for many thermal generators.
- Equity - Given RRO liabilities and hedging costs are not cost-reflective (nor sufficiently dynamic), imposing them on battery storage would effectively be a cross-subsidy to true end-customers loads (that do contribute to reliability risks) and would not represent the actual marginal cost or benefit of the service provided from batteries.

- Double Paying - unlike scheduled loads, scheduled bi-directional assets can provide energy and system services to mitigate reliability risks, incurring charging costs to do so. It seems counter to the intent of the RRO to force these bi-directional assets to then purchase additional contracts from thermal plant, many of which have their own reliability concerns.
- Market distortions – preserving RRO liabilities would place a direct cost impost on battery storage (e.g. for providing lower FCAS services), and therefore add to the spread required for raise or generation services (i.e. RRO costs would need to be recovered through higher bid prices). This would distort the bid-stack and advantage more expensive scheduled generators that are already exempt. This will inevitably lead to higher prices for consumers.
- Investment distortions – the battery storage business model is built around serving customers, as is the case for other generators. With ongoing reforms and existing market barriers still being addressed, the commercial case for battery storage is still evolving and is highly price sensitive. Embedding RRO liabilities effectively increases the commercial risk of new (and existing) battery projects, adding administrative and operating costs to manage, and in turn increasing the incentives required from out of market contracts or government policy (e.g. the Capacity Investment Scheme).
- PFR Precedence: It is worth noting the precedence of treating battery storage differently under the recent Primary Frequency Response Rule Change that places additional obligations on scheduled bi-directional units that are not simply loads.

5 Conclusion – Next Steps and Timing

As summarised above, Tesla, Neoen and Iberdrola believe there is a clear justification for a simple rule change that will bring immediate benefits to the NEM and more accurately align with the original intention of the RRO. Under the scenario where no change is made, the current RRO liability definition will continue to create significant uncertainty for existing and new battery storage projects, with significant short-term implications for contracting the provision of system security services (e.g. a battery operator may be reluctant to provide system strength or SIPS services over summer periods due to concerns about RRO compliance conflicts).

We note the next potential RRO Regulatory Period is forecast in NSW from 1 Dec 2025 to 28 Feb 2026, 2-9pm. The 'Relevant Contract Position Day' is therefore currently Dec 2024. To avoid either battery storage having to secure unnecessary hedge contracts, or withdrawing their system services in NSW, we consider it critical that the exemption outlined in this rule change be made effective by December 2024.

Initial stakeholder feedback across industry, OEMs and energy consumer groups has been positive and signals 'in-principle' support. We look forward to working with the Commission on a streamlined progression of this rule change request.

Appendix A – Relevant Rules

Section 14D of the *National Electricity (South Australia) Act 1996* defines liable entity for a region, for the purposes of the RRO:

(1) Each of the following is a liable entity for a region:

(a) a person who is a Registered participant mentioned in section 11(4)(a); (b) a person mentioned in section 11(4)

(b) prescribed by the Rules to be a liable entity for the reliability obligations;

(c) another person who has elected, under section 14E, to assume responsibility for the reliability obligations of a person mentioned in paragraph (a).

(2) However, a person mentioned in subsection (1)(a) is not a liable entity for a region

(a) if the person is a Registered participant mentioned in subsection (1)(a) who is prescribed by the Rules not to be a liable entity for the reliability obligations; or

(b) to the extent a person mentioned in subsection (1)(c) has elected to assume the person's responsibility for the reliability obligations for the region.

This position is then extrapolated into the National Electricity Rules

Current rule: 4A.D.2

(a) A person is a liable entity for the region if:

(1) the person is registered as a *Market Customer* for a connection point in that *region* at the end of the contract position day but only to the extent there is no opt-in customer for that *connection point* at the end of the contract position day;”

(b) A person who is a Market Customer is not a liable entity for a region if:

(1) it is not registered for a *connection point* in that *region* at the end of the contract position day; or

(2) the aggregate of all *loads* at the *connection points* in that *region* for which it is a *Market Customer* at the end of the contract position day is equal to or less than 10 GWh per annum as determined in accordance with the Contracts and Firmness Guidelines.

Rule to apply from IESS Change (June-24): 4A.D.2

(a) A person is a liable entity for the region if:

(1) the person is a Market Customer or Integrated Resource Provider and is financially responsible for a connection point in that region at the end of the contract position day but

only to the extent there is no opt-in customer for that connection point at the end of the contract position day

(b) A person who is a Market Customer <u>or Integrated Resource Provider</u> is not a liable entity for a region if:

(1) it is not <u>financially responsible</u> for a connection point in that region at the end of the contract position day; or

(2) the aggregate consumption of electricity of all connection points in that region for which it is financially responsible at the end of the contract position day (excluding any market connection point for a market generating unit or small generating unit) is equal to or less than 10 GWh per annum as determined in accordance with the Contracts and Firmness Guidelines

Appendix B – RRO Periods

Instrument	State	Period
T-3, Oct 2022	NSW	1 Dec 2025 – 28 Feb 2026, 2-9pm
Ministerial, Jan 2023	SA	12 Jan 2026 – 13 Mar 2026, 3-9pm
T-3, Oct 2023	Vic	1 Dec 2026 – 28 Feb 2027, 3-9pm
T-3, Nov 2023	SA	1 Dec 2026 – 28 Feb 27, 5-9pm