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Industry-Led Electricity Contract Co-Design Working Group
Lodged via portal at: [ESEM Contract Co-Design Consultation](#)

Response to the ESEM Contract Co-Design Consultation

The Clean Energy Investor Group (CEIG) welcomes the opportunity to provide feedback on contract structures for the Electricity Services Entry Mechanism.

CEIG represents domestic and global renewable energy developers and investors, with approximately 18GW of renewable energy capacity in the NEM across 139 power stations and a combined portfolio value of more than \$41 billion. CEIG members' project pipeline is estimated to be more than 150GW across Australia. CEIG strongly advocates for an efficient transition to a clean energy future on behalf of the investors who will provide the low-cost capital required for this transition.

REGIONAL REFERENCE PPA (RRPPA)

1. Is the proposed contract structure suitable for a range of bulk energy technologies?

- We strongly endorse the RRPPA. In addition to being fungible and tradable we consider it achieves a sensible balance between seller and buyer risk, provided key features yet-to-be-resolved support project bankability (such as treatment of Force Majeure, introduction of a cap on spot price exposure and detailed drafting of Master Agreements).
- A key benefit in our view is that by using a weighted average of generation from the relevant technology's fleet in a region as the basis for the contract (i.e. the reference production index) it will provide a firmer shape for buyers than would be possible from individual projects. We also support solar and wind-specific reference fleets, as the two have fundamentally different generation shapes. A combined index would not provide an adequate hedge for either.
- The RRPPA indexed settlement is superior to the fixed-volume obligations under the DWA swaps, which would have created bankability risks for weather-dependent assets.
- The structure should in principle extend to other variable renewable energy technologies. However, its effectiveness will depend on the presence of sufficient

fleet depth to produce a stable and representative index, likely limiting its utility to wind and solar in most regions.

- The design of the bulk energy contract should ensure that sellers are not incentivised to co-locate energy storage purely for the purpose of managing FM risk or spot price exposure (rather than for genuine market reasons). These issues should be resolved through contract design. Otherwise, the incentive to co-locate physical assets would inefficiently undermine the role of the shaping and firming contracts.
- The Working Group should check its RRPPA detailed design against the findings of bankability study(ies) commissioned by ASL (which should be made public) and extensive real-world bankability testing with major financiers experienced in the Australian market.

2. Does a cap on spot price exposure aligned to the strike price of the firming product (eg. \$600/MWh) appropriately balance risks for sellers and buyers?

- We strongly support the inclusion of a spot price cap in the RRPPA as this helps manage extreme basis risk exposure, which is critical for bankability.
- Aligning this cap to the firming product strike price has logical coherence. So that risks remain symmetrical for buyers and sellers, the cap should be the same as the firming product strike, as buyers will need to procure firming products to cover their exposure above the cap.
- We prefer a \$600 cap (cf. \$300). While a higher cap reduces the seller's protection from the spot price in respect of the RRPPA, it increases the value of the contract to buyers, which should be reflected by an increased willingness of buyers to enter into a RRPPA, all other things equal. To the extent this allows projects to secure more contracted revenue, this will support bankability.
- The final value of the cap should also reflect expected future spot volatility and what firming assets need to deliver projects at a reasonable return, and the Working Group should consider the pros and cons of indexing the cap over time. Further analysis of the price duration curve above \$300 would help inform this.

3. Is a negative price provision required for the proposed contract, noting it is settled against the Reference Fleet's performance and LGCs/REGOs are not included in swap? If so, is a volume knock-out (no settlement during negative price periods) or a \$0 price floor more preferable?

- A negative price provision is required. Negative price periods are increasingly common in the NEM and their frequency will grow as renewable penetration

increases. Without a mechanism, settlement during these periods could produce disproportionate payments and create perverse dispatch incentives.

- Our preference is for a \$0 price floor. Both options protect buyers from the disproportionate payments that would otherwise arise during negative price periods, so the choice between them largely comes down to how the remaining value is shared. A \$0 floor gives that value to sellers, providing more stable and predictable cashflows that support bankability, which should flow through to more competitive strike prices. It is also more consistent with approaches taken in other government underwriting schemes. By contrast, a volume knock-out would remove contract revenue precisely when sellers are most exposed to losses.
- Using a price floor alongside an index based on actual generation does create a complexity: generators settling against a regional index would have no incentive to keep running during negative pricing periods; if enough generators actively curtail output, this could materially distort the index shape and undermine the credibility of the index as a reference point for contracting, as it would become a lot less stable and more difficult for buyers to hedge against.
- The solution would be to use Unconstrained Intermittent Generation Forecast (UIGF) as the basis for the index volume during negative pricing intervals, rather than actual dispatched generation. The UIGF would provide an index volume that reflects what the fleet would have generated absent any curtailment, removing the feedback loop.

4. Does the proposed design of the Reference Production Index appropriately balance risks for sellers (primarily basis risk) and buyers (long-term value of the product)?

- We broadly support the index design, subject to the following comments:
 - NEM regional level is appropriate for most regions, as sub-regional indexes create the risk of reduced liquidity. Larger jurisdictions such as Queensland and NSW wind may be separate cases, however, due to greater within-state resource shape variability, meaning a single state-wide index could provide a less effective hedge for some projects. Further analysis of within-state variability in Queensland and NSW wind would assist.
 - All generators above 30 MW should be included, to ensure the index includes the commercial-scale assets that buyers are hedging against.
 - We support a percentage contribution cap that prevents large projects from distorting the index in early years. For most jurisdictions, this could be 10-15%. For jurisdictions with less variable renewable capacity such as Tasmania, this may need to be set higher. For states with significant intra state wind variability, regional contribution caps could also be considered to ensure the index appropriately represents the spread of wind yields.

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- o A cadence of annual updates to the reference fleet index is appropriate, providing stability while allowing the index to adapt over time. Transition rules at each annual reset need to be clearly specified, so that contracts referencing the prior fleet index remain valid.
 - o We strongly support real-time publication of the index value to support the secondary market.
 - o Reference Fleet transparency will be essential for sellers to have confidence in using the Reference Production Index for settlement. We seek further clarity on:
 - ♣ **Fleet composition and methodology:** sellers will need a thorough understanding of the Reference Fleet, including the location and technology composition of its constituent projects, to model the correlation between the fleet and their own projects.
 - ♣ **Fleet evolution:** given the known issue of reference drift, there needs to be a clear and predictable methodology for how new projects are added to the index and how the fleet evolves over time, including at each annual reset.
 - ♣ **Treatment of offshore wind:** offshore wind should be treated as a separate reference fleet. Its higher capacity factors and low correlation with the majority of onshore wind in Victoria mean that combining the two in a single index would introduce higher basis risk.
 - o Actual dispatched generation is preferred as the data source, rather than synthetic alternatives, as it reflects real fleet performance including any network curtailment effects. The exception should be negative price intervals, where the index should use the UIGF (or a similar unconstrained measure) so that efficient curtailment by the fleet does not erode index volume (see our response to Q3).
 - o The Fleet MLF should be included in the calculation of the Reference Production Index. This would be applied by adjusting each project's generation by its AEMO-published annual MLF when calculating the Reference Production Index, so that the index reflects the fleet's loss-adjusted output. The contract volume would then be based on this adjusted index. Because MLFs are published annually, the adjustment would be known ahead of each financial year and would apply uniformly to all contracts, so it would not affect fungibility. This would be coherent with the design of the Reference Production Index, aiming to pass fleet-related risk to the Buyer, and to leave the Seller with the project-specific risk.

SHAPING: DYNAMIC TIME OF DAY BLOCK SPREAD SWAP

5. Does the proposed approach to determining charge/discharge periods on a day ahead basis, using residual demand calculation, appropriately balance operational risks/simplicity with long-term value?

- From a seller's perspective, the key requirement is that charge and discharge periods are known sufficiently in advance. We nonetheless note the following risks.
- The Time of Day Blocks are independent from one day to the next. In theory, this means there could be two consecutive Discharge Blocks across two days, which may be impossible to physically back depending on the duration of the BESS relative to the swap. Financiers are likely to expect a BESS to be able to physically follow or outperform the nominated blocks, so this could affect bankability. This could be addressed by adding a constraint requiring consecutive periods over several days not to exceed a cumulative threshold.
- In relation to the use of the determination being based on forecast residual demand, further consideration should be given to whether this is appropriate in high-wind states (e.g. South Australia). In addition, this could create a dependency on day-ahead renewables generation forecasts which may not be accurate. As noted below, if BESS operators are incentivised to follow the nominated blocks, this could result in perverse market outcomes.
- Overall, consideration should be given to the situation currently being experienced in Western Australia's Wholesale Energy Market, whereby the proportion of the BESS fleet responding to the same fixed obligation interval artificially drives demand and increases the price directly (1-2 hours) before the relevant interval – resulting in perverse market outcomes. While we appreciate the theory is that BESS operators will respond to the market signals of the day this 1) may not be accepted by financiers who want to ensure the contracted position is covered and 2) it may be challenging to make these trade-off decisions accurately in real-time.
- The shaping product is intended to protect buyers against high-price events, but its discharge periods are set ex ante based on residual demand, so high-price events may fall outside them. Buyers may therefore also buy the firming product or other caps, which would overlap with the shaping contract for high-price events within the discharge periods. We suggest the Working Group consider applying a \$600/MWh cap to the spot price in the shaping contract, consistent with the RRPPA. This would protect sellers against outages or curtailment during high-price events, and allow the shaping and firming products to work together without double counting.

6. Does the use of AEMO's forecast data to determine shaping periods result in any material risks to the usability of this contract over the long term?

- There is risk that changes to AEMO's methodology could materially affect contract settlement. Any changes should therefore be subject to consultation processes before a determination.

7. Does the proposed approach of determining nominations at 4pm on a day ahead basis pose any material operational risks?

- This appears operationally workable. As periods would be set for all contracts under a standardised methodology rather than nominated by individual participants, sellers can plan around them and continue to rebid to optimise their dispatch within and around the nominated periods.

8. Does the proposed Daily Shaping Period that commences at the Trading Interval ending at 9:05 and finishes at the Trading Interval ending at 09:05 the following day pose any material operational risks?

- We query the proposed start of the Daily Shaping Period (DSP) at the Trading Interval (TI) ending 09:05. Under the proposed approach, determining the charge and discharge periods would require residual demand forecasts from two different data sets: pre-dispatch data from the TI ending 09:05 through to the TI ending 04:00 the following day, and ST PASA data from the TI ending 04:05 through to the TI ending 09:00.
- We propose instead that the DSP commence at the TI ending 04:05 and conclude at the TI ending 04:00 the following day, aligning with the NEM trading day. This would allow charge and discharge periods to be determined using pre-dispatch data only, simplifying the process and avoiding the need to combine two different forecast data sets.
- Pre-dispatch data would also provide a more relevant forecast, as it takes into account generator bids and offers and a supply-demand balance to determine an economically optimised dispatch. This approach would still give the Seller 12 hours to manage its position following the 16:00 day-ahead determination time.

FIRMING: \$600 PRICE CAP

9. Is a \$600 cap, in comparison to a \$300 cap, appropriate to support the entry of new firming assets? If not, why?

- A \$600 cap is preferred to support new firming assets, as it allows for more merchant upside for projects. Most importantly, it should align with the cap on spot price exposure in the RRPPA (see our response to Q2): buyers will rely on

the firming product to cover their exposure above the RRPPA cap, so the two need to match for the contracts to work as a set. In addition, a higher strike allows firming sellers to retain merchant revenue up to \$600 and reduces the frequency of payouts, allowing lower premiums. A lower cap would require sellers to charge higher premiums to compensate for more frequent payouts.

COMMON CONTRACT FEATURES

10. Are there any concerns with the proposed weekly settlement approach, aligned to the AEMO settlement calendar?

- Weekly settlement is workable, but the Working Group should consider the benefits of quarterly (or longer) settlement periods. These would smooth short-term variations and reduce the cash balances projects must hold to cover short-term gaps, lowering working capital and initial capital requirements and improving bankability.

11. Are alternate approaches to manage FM risk exposure (outside of the contracts) required to support the entry of the new assets?

- Yes. Without adequate FM risk management (including curtailment outside the seller's control), the bulk energy contracts will not be bankable for project-financed assets. A higher investment risk profile would also reduce Australia's attractiveness relative to other jurisdictions competing for renewable energy investment.
- FM risk cannot, structurally, pass through to buyers in a fungible contract, because there is no connection between the physical asset and the purchased electricity. FM risk should therefore be managed at the ESEM Administrator (ESEMA) level (which will be more efficient). Noting also that in part the FM risks have been passed through to customers through the price cap provisions, so it is appropriate that projects as a collective wear part of this risk as well.
- The FM events of most concern are those that affect one plant or one part of the network while the rest of the regional fleet keeps generating. In these cases the Reference Production Index provides no relief, and the seller must still settle on fleet volume it did not produce. Examples include transmission tower collapse (e.g. the Anakie microburst in February 2024), hail damage at a solar farm, network islanding (e.g. Broken Hill) and fire damage at a site. Region-wide events, such as a wind drought, are partly absorbed because fleet output also falls.
- We prefer FM protection to be built into the ESEM framework, rather than operate through a separate government scheme that could be subject to political/legislative change.

- A range of possible approaches should be considered, for example: a pooled insurance administered by ESEMA with premiums funded by project cash flows; a levy on contract volumes used to build a reserve fund; or ESEMA retaining the ability to close out positions affected by FM events. FM risks covered centrally would need to be clearly specified and likely will need to separate out uncorrelated or project specific FM risks from those FM risks likely to impact the ability of multiple projects to fund their contractual obligations (such as an unforced outage of a large transmission line to which multiple projects are connected). ESEMA should focus on these correlated or systemic risks which are likely to be difficult to insure privately.
- We understand that the detailed approach to managing FM risk will likely be determined in early 2027. However, we emphasise that a clear, high-level pathway for managing FM risk needs to be established before the suitability of the proposed contract structure to support project bankability can be assessed.

OVERARCHING FEEDBACK

12. Do the proposed contract structures achieve the Working Group's Terms of Reference and perform well against the identified evaluation criteria?

- Overall, we support the Contract Co-Design Working Group's preferred bulk energy product and leave for others to comment in more detail on the firming and shaping products.
- Two major pieces that need to be resolved to address bankability metrics (and seller attractiveness) are FM issues and the negative pricing mechanism.

13. Are there any concerns with the ability of the contract structures proposed to be subject to a Market Making Obligation (MMO) in the future?

- The interaction between the MMO and the contract recycling program needs to be clearly defined so the two mechanisms reinforce rather than crowd each other out.
- A functioning MMO requires secondary market liquidity, which needs broad participation. This needs resolution on FM, negative price mechanisms and index design to be resolved.

14. Will the proposed contract structures, in conjunction with other risk management contracts, such as flat swaps, evening peak swaps or caps, be effective for buyers (eg. retailers, large loads, etc) to manage financial risks?

- We consider that the suite of products can provide an effective hedge package for retailers and large loads: it provides diversified bulk energy exposure, reduced single-asset curtailment risk, the inherent fungibility of the RRPPA, and insurance against high-price events.
- A liquid secondary market, well-functioning contract recycling and an effective MMO will also provide a framework for risk management.
- The Working Group should consider the total volume of ESEM contracts issued relative to demand. ESEM was intended to complement the existing OTC offtake market by extending offtake tenor (e.g. years 7-15). Without a limit, ESEM contracts could crowd out OTC offtake demand, putting downward pressure on achievable project pricing and reducing the number of projects reaching financial close. Bankability assessments should also test real-world combinations of ESEM products with existing risk management contracts.