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NSW Department of Climate Change, Energy, the Environment and Water

Submitted to: energy.consult@dpie.nsw.gov.au

Submission to NSW Office of Energy and Climate Change – Orderly Exit Management Framework consultation paper

Delta Electricity (Delta) welcomes the opportunity to respond to the NSW Department of Climate Change, Energy, the Environment and Water's (NSW DCCEEW) consultation paper on the Orderly Exit Management Framework (OEMF).

Delta understands the reasons for the development of the OEMF but considers the final design needs to be particularly cognisant of how it will impact on the current competitive generation market. The final design needs to ensure that it does not provide a stop-gap, while renewables and storage are built to sufficient levels, at the expense of damaging these competitive processes in the medium and longer-term.

Overall, Delta considers:

- Stages 1 and 2 need to be carefully considered.
  - The proposed prescribed information to be supplied at Stage 1 is excessive and would not encourage genuine discussion for a voluntary agreement to be reached prior to considering Stage 3, if required.
  - Jurisdictions should rely on ESOO forecasts by AEMO in identifying whether reliability gaps appear and what system security needs are required. The costs of this framework will ultimately be borne by customers, so decisions on system needs should not be at the discretion of the Minister of the day and potentially influenced by other political forces.
- Stage 3, Notice of Mandatory Operation (NMO), should:
  - be utilised only when absolutely necessary and as a last resort;
  - not impact on existing competitive market dynamics; and
  - not provide subsidies to generators that would unfairly impact on the commercial and competitive ability of other generators in the market. If generators subject to a NMO were to receive a subsidy that improved their ability to compete, this would ultimately lead to inefficient outcomes and higher costs passed onto customers.

Delta provides responses to the consultation paper questions below.

To discuss further please contact me at joel.aulbury@de.com.au.

Yours sincerely,

Joel Aulbury

Joel Aulbury
Regulation and Strategy Manager

Key question	Delta's response
1. Is this mothballing precondition appropriate?	Delta does not agree that the OEM framework should include scenarios where generating plant may be mothballed. At this phase of the transition, mothballing decisions are more likely to be decided based on commercial viability, not asset end of life. Delta considers the inclusion in the OEM would be regulatory overreach, and in any event, if a plant was mothballed but then system supply became a concern and commercial viability market conditions improved the plant could be brought back into service.
2. Do you have a view on the timings in the mothballing precondition?	Delta disagrees with the inclusion of mothballing provisions.
3. Are there concerns with requiring the Prescribed Information to be provided when the OEM Generator notifies of a change to its closure date (or applies to the AER for an exemption from the notice of closure requirements)? If yes, please provide details.	Delta disagrees with the information an OEM Generator would be required to provide at Stage 1 of the OEMF process. This requirement is excessive and burdensome, particularly as it is required before a search for alternative solutions, or a voluntary agreement has been attempted. Delta agrees with the AEC's submission in that for the OEMF to be a true negotiate model, Stage 3 voluntary negotiation does not need to proceed with both parties having full information. The nature of voluntary negotiation requires incomplete information to come to a mutually beneficial agreement. A generator should not know exactly how much a jurisdiction would be willing to pay to keep that unit open for an additional period of time, and equally a jurisdiction should not know exactly what a Generator would be willing to accept to remain open if a negotiation is voluntary. Besides the publicly available information, such as closure dates and regulatory approvals, no other information should be provided until Stage 4, Notice of Mandatory Operation, is reached.

Key question	Delta's response
4. Noting that generators may operate under complex corporate structures, what are the best means for addressing related entities that provide services that are required for the operation of the System Significant Generator?	As noted above, Delta considers most of the information required at Stage 1 should only be required if a generator reaches Stage 4 of the process.
5. Are there other specific insurances that should be maintained?	It is likely that generators would hold different levels of insurance, depending on its strategy and risk appetite and most importantly due to insurance accessibility. Delta notes that business interruptibility insurance is likely to be difficult or impossible to get once an asset is past its technical life and has been forced to stay open as a result of a NMO. While a generator under a NMO would apply its best endeavours to deliver what is required, the risk of no insurance, or cost of obtaining insurance, may be unacceptable from a commercial perspective, which may be a factor as to why a notice of closure was brought forward. With this in mind, the level of insurance required should be set by the Minister and borne by the relevant jurisdiction.
6. What information should be published to the market regarding AER decisions?	Delta is comfortable with the information set out in Section 10.2 being made available to the market in the event a Notice for Mandatory Operation is issued.

Key question	Delta's response
7. What are your views on the appropriateness of the proposed commercial component outlined in section 10.10?	Delta agrees with the AEC's response to this question, in particular, that the proposed commercial component puts the risk of outages onto the generator. And given the end-of-life context, coupled with the generators stated intention to close the plant, this means the outage risk cannot reasonably be borne by the generator alone. Delta also notes it is necessary to break down the commercial component into two to account for the uncertainty of aggregate generation of the plant. The payment for expected capex/FOM needs to also include costs incurred prior to the extension period that would otherwise not be – ie additional outages or fuel sourcing arrangements.
8. Is an alternative commercial component approach preferred and, if so, why?	Agree with the AEC response. Voluntary negotiations should still be pursued where a beneficial outcome for both parties involved can be found.

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9. Are there other key issues that need to be considered as part of the commercial component?	Agree with the AEC response. In particular: • Where a Minister can restrict the operation of a generator, this creates risk for the ability of a generator to cover its hedge or retail load, and may result in operating the plant in a way that was not intended or suitable for its plant type. • If a restricted operation regime was imposed on a generator, the commercial compensation would need to recognise this and all the generator to recover a reasonable margin commensurate with the cost, risk and investment involved. • If performance requirements are imposed on generators, they need to consider the age, technical limitations, and maintenance state. It may be extremely expensive or practically impossible for a generator to take on this risk, and therefore it may be necessary for the jurisdiction to take on the cost of this risk. • A NMO should be consulted on with the affected generator/s before being made final.
10. Should the financial model include an additional incentive component, even if small, so that the generator has some incentive to contain costs?	Agree with the AEC response. A small incentive component is not required, as it will further complicate an already complex set of arrangements which should only be used as a last resort and for a limited time.

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11. How should services provided by related entities be treated?	Agree with the AEC response. That the costs of services provided by related entities will need to be recouped just as direct costs would. To the extent there are common costs across multiple generators, the AER will need to advise on a cost allocation methodology, or rely on pre-existing internal cost allocations already in place. If the concern relates to the risk that related entities inflating the internal transfer pricing to game the compensation arrangement, the AER could examine the historical contracts with related parties. The historic contracts with related parties have been struck under competitive market settings, with no incentive to inflate transfer prices.
12. Should the AER have the ability to "look through" the billing arrangements of services provided by related entities to see the actual costs without mark ups?	Delta considers the AER having the regulatory reach would seem burdensome and unnecessary. As noted in response to Q11, if concerned the AER could review historical arrangements and costs to check they are similar and reasonable.
13. How should the return to the generator be calculated in the case of a swap?	If the swap is effectively used similar to a peak contract, where the Minister has discretion on when the plant may operate then the agreed rates should reflect this. Assuming fixed costs are fully recovered there is still a need for a reasonable return on the investment, to be made as if it did not have restricted operating conditions, commensurate with the investment made.
14. Should there be a ‘true-up’ settlement in the event that actual capital expenditure and FOM expenses (fixed costs in the case of gas fired generators) differ materially from the ex-ante determination on which payments to the OEM Generator were based?	This seems reasonable as long as the true-up is symmetrical and does not leave the generator with greater risk.
15. How should the strike price for a cap for a gas-fired generator be determined (e.g., set at a fixed price, linked to the price of gas, or an alternative method)?	Delta notes a standard strike price of $300 MWh might be reasonable however if the actual price of gas varies materially from this, it may need to be revised.

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16. What do you think of using the proposed new transmission cost recovery mechanism compared to the existing distribution network cost recovery mechanism contained in the national electricity rules ("Jurisdictional Scheme")?	Agree with the AEC response. Costs passed through to customers should be as transparent as possible.
17. Noting the aim of a cost recovery estimate is to even out impact to energy consumers, should the estimation be averaged out over the entire period or allocated as expected by year with a re-estimation every year to correct for any variations?	Agree with the AEC response. The estimation should be performed annually, as the AER can vary the swap price annually.
18. Would the shielded loss and gain option be a more suitable commercial component approach for the Notice for Mandatory Operation compared to the financial swap approach detailed in the body of the consultation paper?	No comment.