MONASH University

MONASH BUSINESS SCHOOL

Dr Kerry Schott

Chair, Energy Security Board

9 June 2021

Dear Dr Schott,

Re: ESB Options Paper (April 2021)

Thank you and the ESB staff for the invitation to comment on the Options Paper. We are academic economists at Monash University, and we specialise on the economics of electricity markets. This letter lays out some comments in summary form, on which we expand further in an accompanying attachment.

- The development of Locational Marginal Pricing (LMP) is a priority for the NEM.

  While we view the congestion management model as a step in the right direction, we suggest that instead of informally labelling options as "interim" or "grandfathered," any rule change should contain the introduction of LMP with any interim or grandfathered component explicitly listed (including explicit transition dates).
- We have serious concerns regarding the physical Retail Reliability Obligation (RRO).
  - We do not agree that there is an economic rationale for the RRO, or that it is the best solution to any market failure it is intended to correct.
  - There is a distinct risk that the RRO will undermine the development of an active demand side of the market.
- It is unclear whether integrated ahead markets received due consideration, especially as they are in operation in many other jurisdictions.
  - Ahead markets offer generators a transparent mechanism to specify binding delivery, modulo dispatch constraints.
  - Like forward markets, ahead markets are known to be pro-competitive.
  - Combinatorial ahead markets can efficiently accommodate different generation technologies, and multiple service markets.
- We note a lack of emphasis regarding the deployment and integration of grid-scale storage technologies.
  - Storage is a major bottleneck for unlocking further renewable energy penetration.
  - Storage possesses different properties than conventional generation, which require different market design considerations.

We attach a brief report in which we further expand on these points and offer other general comments.

Sincerely,

Guillaume Roger
Associate Director
Monash Energy Institute

Gordon Leslie
Lecturer, Department of Economics,
Monash University

Submission in response to the ESB Post 2025 Options paper.

This submission does not attempt to answer the specific questions raised for comments in the options paper. Rather, it makes broader comments on the options laid out by the ESB, it discusses some omissions and provides recommendations where suitable.

The most pressing market design issues for the NEM are:-

- To better align spot prices with the time- and location-varying social marginal costs of energy, most relevant to the discussion on congestion management;
- To better align compensation and payments to/from participants with the social cost/benefit of their actions. This is most relevant to the discussion on system strength and inertia, day-ahead market and to the integration of storage into the NEM.

Achieving these goals will help incentivise the efficient deployment of new technologies and improve the robustness of the market design to accommodate current and future supply-side and demand-side technologies and assets. This is especially relevant given the rapid development of storage technologies and their pioneering deployment in the NEM.

First, we view the Option Paper's assessment of locational marginal pricing as well-motivated, and **second** we also view favourably the proposal to develop methods that value system strength and inertia.

Third, we express strong concerns regarding the physical retailer reliability obligation (physical RRO) option that is proposed. We do not observe an obvious economic rationale for its introduction, and are concerned that it will be counterproductive for improving the efficiency of the NEM.

Fourth, we raise that a day-ahead market would help efficiently facilitate many of the issues and options discussed in the Options Paper.

Fifth and finally, we note considerations for grid-scale storage technologies in designing markets for electricity, and the importance of considering the impact any reform will have on providing suitable incentives for the efficient deployment and operation of these assets.

1) Locational marginal pricing

A pre-requisite for markets to deliver efficient outcomes is for prices to equal the social marginal cost of production.[1]

We are mostly in agreement with arguments for the need to price the network externalities that arise from congestion listed in the Options Paper and the recent CoGaTI review

[1] In times of scarcity, prices should equate to the social marginal benefit of consumption.

conducted by the AEMC. The review is well-motivated and the economic arguments are transparent. We are able to expand further on this issue if requested to do so.

Although the options raised represent a move in the right direction, we do express some concern about the guidance provided on this crucial issue, summarized on pages 89-90:

"… the ESB's preferred solution for access reform is to shift to locational marginal pricing and financial transmission rights. It is a more comprehensive access solution to the issues raised. It is a well-established model that has been successfully applied in numerous overseas markets for decades."

"While the immediate reforms and medium-term access options will assist congestion management in some ways, by their very nature they are a sub-optimal long-term solution. They are cheaper, quicker and less disruptive to implement, but do not fully resolve the problems that we are trying to address. These short to medium term solutions are better thought of as interim, or grandfathering, solutions on the way to fully implementing a future access framework to drive better outcomes for the NEM and consumers."

We recommend that if locational marginal pricing (LMP) is not an initial reform then a clear timeline be provided for its implementation. We recommend that that instead of informally labelling options as "interim" or "grandfathered," any rule change should contain the introduction of LMP with any interim or grandfathered component explicitly listed with a transition date. This will capitalize the large amounts of work the ESB, AEMC and participants in the Technical Working Groups have devoted to this issue in recent time, and avoid the need to revisit these same issues in the future, in addition to providing guidance for future investment.

2) Inertia and system strength services

The Options Paper correctly identifies a need for an arrangement to supply inertia services. System inertia in fact refers to the physical inertia of rotating masses when they produce energy that is dispatched. That physical inertia entails kinetic energy which counters frequency deviations, and so is the first responder to these deviations – before FCAS can respond. At its core, it is an injection or a withdrawal of energy. It is a by-product of generation and, so far, a positive externality supplied by thermal generator, and so it is not currently remunerated. Likewise, *synthetic* inertia refers to fast injection or withdrawal of energy to correct frequency deviations, which batteries can address. This has been recently demonstrated by the Hornsdale Power Reserve during the Callide failure.

However, before speaking of a market for synthetic inertia, one has to ask how to *value* inertia. With a broad brush, the *value* of inertia lies in the ability of the power system to accommodate more renewable energy and displace thermal generation, and in enhancing interstate trade by relaxing the interconnector utilization constraints. In other words, it is the price difference that is induced by dispatching more renewable, or more imported, energy (rather than having to rely on conventional generation). Once one knows how to value inertia, one can elicit a demand for inertia, from which a market may be created. The FCAS market is *not* a good example to follow, in that there is no actual formulation of demand for FCAS. Rather, the

FCAS market only elicits supply. The last question is concerned with *who* should pay for synthetic inertia services, to which we return below.

System strength is also mentioned as an area of concern, in echo to AEMO's view on the question. Unlike frequency control, system strength is not addressed by energy injections. Rather it is concerned with voltage management and so may be controlled using reactive power. Like inertia, this service has long been supplied as a by-product of thermal generation; as thermal generators progressively retire, this may result in short supply. There may be two alternatives to this problem. One, as for synthetic inertia, is to *value* system strength and use this information to construct a demand for reactive power. This reactive power can be supplied by entities operating power inverters. Although more consideration is required on this issue, the opportunity cost of generating reactive power must be identified. It may manifest itself either in the form of energy that is not dispatched or additional transmission losses. Hence this cost varies over time and may be zero (when the price of energy is zero). The second avenue is to mandate that renewable energy suppliers, including households, use an appropriate inverter technology to better control voltage fluctuations.

In both the synthetic inertia and the system strength cases, a question remains: *who* should pay for these services that were to date neither available, nor necessary. There is a view that inertia and system strength are "transmission problems" and so should be dealt with by NSPs. In the alternative, foundational economics asserts that externalities should be internalised; for example, the polluter pays, not the taxpayer, for remediation. Here the externality is caused not by NSPs but by asynchronous generation, who should therefore pay for the remedy. In practice, a solution may be for AEMO to procure the services that are required system-wide, and recover costs from asynchronous generators than have not installed the appropriate inverter technology.

We note further that synthetic inertia services can be delivered by fast-responding storage, which renders storage integration even more important.

3) The physical retailer reliability obligation and generator exit

The physical retailer reliability obligation and discussion of mechanisms to manage generator exit do not create informative market signals and instead undermines them. We highlight some of the many issues with the RRO and offer one other option for consideration. We do not list the many practical considerations, but acknowledge there could be serious economic and political economy issues related to the determining types of contracts that are admissible, and determining the triggers and requirements of an RRO.

Economic Rationale for the RRO

The Retail Reliability Obligation is a costly imposition on retailers that induces entry barriers in retail. The economic rationale for using an RRO is to prevent future supply shortages. Where there is a high price cap and futures market, with instruments such as contract for differences, there is no need for the RRO. The high price cap sends the appropriate price signals to guide investment decisions, and the contract market delivers the instruments for retailers to be protected against price surges. We also know that as soon as retailers exhibit a modicum of risk aversion they seek full insurance from price variations. (Incidentally, this is what motivated the retailers to become gen-tailers.)

If rejecting the hypothesis of risk aversion, then one should rather impose an obligation to serve consumers, so that the incentive to curtail consumers in high-price periods vanish. This service obligation then spurs retailers to procure energy and to hedge their exposure. There is no need for the RRO. This Obligation is in fact anti-competitive in that, if activated, it forces parties to contract in a manner they would rather not do, and it give gen-tailers a competitive advantage in that they are naturally hedged. It therefore acts as a barrier to entry into retail.

Finally, turning the financial nature of the RRO into an obligation to be backed by physical delivery worsens the phenomenon discussed in that it rules out contracting with a financial intermediary to trade risk. It requires for a retailer to trade with a generator only, which precludes arbitrage and considerably narrows the number of available counterparties. Overall, this can only increase prices.

The RRO undermines other features of well-designed markets

An RRO undermines the pursuit of developing a demand-side of the market, as price-responsive end-users can naturally help mitigate tight supply conditions. Flexible demand, by definition, is prepared to cease consuming energy services when prices reach a certain level. End-users (including households) that might be willing to respond to wholesale prices therefore do not fit within the historical view of the market that is required to justify an RRO. Therefore, many of the options discussed in the options paper are undermined by the RRO.

A helpful "solution" to issues caused by generator exit

If the RRO is motivated by concerns about a market failure arising from the uncertainty of retirement dates of the aging generator fleet, then a simple solution is to require public disclosure of all forward contract positions.

The only way there can be a market failure is if there is an information asymmetry (in combination with scarcity being mis-priced, unlikely given the NEM's high bid cap). Therefore, it is reasonable and cheap to correct this asymmetry by requiring owners of plants that are nominally scheduled for closure over the planning horizon to specify their contract positions. Prices and counterparties to the contracts are not necessary. Entrants and other market participants can therefore use this information to better infer a tighter closure window for major power station closures.

4) Day-ahead markets

We are unclear as to whether integrated ahead markets received due consideration. We are concerned by this because they are an inexpensive option to solve many of the ills in the market that are described and complement many of the options that have been put forward in isolation. Further, there are many working models in operation in many other jurisdictions to provide an evidence base for their effectiveness.

Introducing day-ahead trading opens the door to a *combinatorial* market design, whereby generators may bid for delivery of energy in anything from 5-minute increments to 24-hour commitments. This flexibility in bidding allows *all* generators to meaningfully co-exist and operate, and enable the market operator to find a cost-minimizing dispatch over a 24-hour horizon, rather than 5 minutes. This is crucial because the costs of many actions and services in a given interval are dependent on the operational status of many generation and load assets in the previous interval. In contrast, the current myopic, spot-based merit-order effect can displace generators in a manner that is not dynamically efficient and can induce large volatility in prices, and in supply decisions. The benefits of a day-ahead, *combinatorial* market are multiple:

- Thermal generators can have certainty of cash flow (given the bids and committing dispatch decision), and so bid more aggressively to sell;
- The costs of ramping can be explicitly considered and efficiently subdued;
- In the long run, thermal generators may be able to stay in operation longer and not have to rush to a premature exit;
- The combination of a day-ahead and spot balancing market delivers the pro-competitive benefits of a forward market;

A day ahead market links to many of the considerations raised in the options paper, and can enhance the effectiveness or minimise the costs of many options.

Two-sided markets: For example, Le Chatelier's Principle applies in that the elasticity of demand and supply is greater over a longer than shorter time horizon. Day-ahead markets allow the explicit expression of market participant preferences further ahead of time. This is important in contexts where different inputs or behaviours are possible at long notice than small notice, which is likely to be the case for future demand side participants in the market.

Operating reserves: Although the introduction of operating reserves is contentious[2], a day-ahead market can either make their purpose largely redundant or reduce their cost. The key is in the *combinatorial* market design, which provides a day-ahead schedule that co-optimizes the value of all system services and generation. Further, any measure of system strength and inertia can be preserved since thermal generators can operate in such a market, while they are systematically displaced (through the merit-order effect) in a spot market.

Caveat: Introducing a day-ahead market without locational marginal pricing can lead to inefficiencies, such as those arising out of so-called "INC-DEC" games. We therefore recommend day-ahead markets be considered as part of a holistic market design and not in isolation.

---

[2] In a prior submission we have written of the ills of a market for operating reserves. Operating reserves do not add supply; in the short run, they actually *subtract* from the aggregate supply: some capacity must be reserved. With a lower capacity available for sale, the result is invariably two-fold. First, prices in the wholesale energy market are bound to rise, as generators bid less aggressively their reduced capacity. Second, these operating reserves are bound to be called on with a higher probability, simply because the available supply in the energy market decreases.

5) **Storage integration and test cases for the robustness of the market design**

A useful lens for considering the future market design is to consider whether owners of storage assets can fully capture the economic benefits they deliver via market mechanisms. Any shortcomings in a market design or policy can quickly by highlighted when considering its impact on storage investment or operation -- it is a flexible provider *and* user of energy, and therefore can be harmed or exploit inconsistencies in the market design. The options paper makes some mention of storage, but not from this perspective.

Market design reform is most pressing as battery investment ramps up very rapidly, where market rules will govern the roles in which they are deployed and utilised. This is important because storage is a natural complement to variable renewable energy sources, and nearly all technical issues raised in the Options Paper can at least partially be addressed via battery deployment.

In the context of the issues we raise in this note:

- Locational marginal pricing allows battery owners to capture the positive network externality it can create when relieving congestion. This will encourage further investment in storage technologies and more importantly, at locations that are of greatest economic value from a whole-of-system perspective.
- Establishing markets for system strength and inertia can incentivise batteries to be designed or operated in a way that creates value in these contexts if they have an economic advantage in doing so.
- A (physical) RRO places big questions on how to specify eligible contracts and highlights aspects of economic incoherence inherent to the option. Must a battery be inefficiently operated (for example held out and to remain at full charge throughout the relevant RRO window) in order to be eligible? Can batteries even be eligible since they have a finite generating capacity? Can they be eligible if maintaining an ability to generate at a given power level for 1 hour? 2 hours? 4 hours? A day?
- A day ahead market allows battery assets to maximize their value when cycling by buying at the expected lowest time of day and selling at the expected highest time of day, and then (profitably) deviating from this schedule if conditions change in the balancing market. Further, it allows for the alignment between the most valuable grid services they provide and the privately most profitable services they can provide given the combinatorial market design.
- Although not previously mentioned in this note, storage assets highlight the core issues at play with concerns surrounding "minimum demand" – the phenomenon whereby very little power is drawn from the grid for some hours of the day, which induces very low (often negative) wholesale prices and may induce stability issues. Much of the problem is rooted in policy, such as the net metering arrangements and feed-in tariffs mandated in various states. For example, Victoria mandates that households exporting excess supply of energy be paid 10.9c/kW – or $109/MW. Export conditions typically arise in the early afternoon, when demand is very low anyway and energy trades at very low, and often negative, prices. In other words, the social

value of energy is low, but the private marginal benefit to exporters is very high – the mandated 10.9c/kW. Clearly an analogous policy doesn't make sense for behind the meter storage and would encourage inefficient utilisation if a constant price was paid for injections into the grid for batteries, and withdrawals were subject to the retail price for energy.

Finally, since storage is on the cusp of becoming significant in the NEM, further consideration should be placed on whether the foundational features of the existing market design are still sensible for a market that may integrate larger amounts of storage. Unlike much of the currently installed generation capacity, its role can still be largely shaped. In particular, there is no doubt that a 5-minute (even 1-minute) *myopic* clearing is not the best approach to handle the bidding of entities that use, by their very nature, *dynamic* strategies. That is, strategies that are linked over time in that the actions of a storage unit at time t condition what is possible at time $t+1$. Therefore, the clearing rule is likely to have to be modified to accommodate storage, with significant consequences on the computational burden to arrange the dispatch.

We believe this work is pressing and we remain available for any clarification that may be required.

Guillaume Roger, PhD
Monash University

Gordon Leslie, PhD
Monash University