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Post 2025 Market Design

A reply to a consultation paper of the ESB prepared by

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This submission:

On 7 September 2020, the Energy Security Board issued a consultation document (Post 2025 Market Design Consultation Paper – September 2020) seeking input from stakeholders on a high-level reform approach for the NEM.

This submission addresses the questions asked of stakeholders in the consultation document. In an opening section we also specifically attract the attention of the ESB to some important aspects of the reform agenda.

Guillaume Roger

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Disclaimer:

Section 1: General statement.

First, one must seek to render demand more responsive to have chance of achieving successful reforms. There is no reason for retail prices to not reflect the true cost of energy, just like retail prices reflect scarcity of other commodities – food, fuel, accommodation and so on. A more responsive demand makes for a better allocation of resources. The barriers to eliciting a more responsive demand are low: metering and adoption of new retail tariffs. Some of these tariffs already exist in Victoria, for example. Absent a more elastic demand, wholesale prices are likely to become artificially inflated, or excess supply may be installed. In either case, consumers end up paying.

Second, reserve mechanisms tend to do more harm than good. The main reason is that creating a reserve market implies, at least in the short run, that the available capacity in the spot energy market decreases. This leads to higher spot prices on average.

Third, the high degree of concentration in generation remains a real problem, with multiple consequences. One, it clearly leads to higher prices than necessary. Second, it likely contributes to deterring entry into the generation sector: even though prices are high before entry, they are likely to significantly decrease post entry, thereby making entry unprofitable. This is because scarcity is somewhat artificial at present in the generation sector. Short of breaking up large owners of generation plants, mandatory participation by generators in the contract market is an avenue to promote competition.

Fourth, the careful design of a "two-sided" market – effectively, a double auction – is important to further contribute to demand response by ensuring demand in the wholesale market is elastic. It is also critical to properly integrate storage in the wholesale market, because a storage operator can either buy or sell at any given time, and may choose to charge or discharge at different prices.

Ahead markets feature prominently. They can be very appropriate to deal with dynamic costs (ramping costs) and storage, provided they are carefully designed.

Finally, DER may be more utopia than reality. The main problem is that of double coincidence of wants: when households want to sell, few buyers are present, and conversely. There is a distinct risk of investing in a service that never takes off.

Section 2: Specific questions.

<u>A - RAM -- Questions for stakeholders</u>

1. Do you have views on whether the current resource adequacy mechanisms within the NEM are sufficient to drive investment in the quantity and mix of resources required through the transition?

Except for the RERT, which is designed to satisfy AEMO's operational constraints, there really is no resource adequacy mechanism in the NEM. The only device is the price signals that are sent through either the spot market or the contract market. The RRO may contribute to generating price signals on the contract market, but this is largely unverified so far. This is not to say this lack of formal mechanism is problematic; after all, short of directing investment, price signals are the only device available.

However what is problematic is *how* these price signals are formed. At present the NEM suffers from two drawbacks, which distort the informational content of prices. The first one is not new: the NEM is highly concentrated. Therefore generators enjoy significant market power and as a result clearing prices sit well above marginal cost for many generating units; it is as if scarcity were manufactured. While high prices should encourage entry, the concern for a potential entrant is a price collapse following entry. This anticipated collapse in prices may be in retaliation to entry, or simply from the competitive pressure entry exerts on artificially high prices. Such a problem does not exist in a competitive market, where no participant holds enough market power to move prices. In a competitive market scarcity cannot be manufactured; high prices are true indicators of scarcity and of profitable entry. Therefore, even though market structure is a matter of competition policy, it should be addressed as part of this reform, so that price signals become more credible to investors.

The second problem is a more recent phenomenon associated with the intermittent nature of renewable generation interacting with the current spot market design. In any pricing interval, renewable generation can displace any other form of generation thanks to its cost advantage (low marginal cost). When thermal generation is needed again, it needs high-enough a price to justifying is ramping costs. These fixed costs cannot be amortised over long-enough a duration; in the end the spot price becomes very volatile, so difficult to forecast, and the generation intervals are also difficult to anticipate (see Jha and Leslie, 2020). This makes it both very profitable to existing generators, but simultaneously very difficult for new entrants to forecast their revenue. Again, prices lack informational content.

This problem arises from the interaction of dynamic costs (ramping costs) and a static market design; its solution is for the market to internalize the reality of dynamic costs, as pointed out by Jha and Leslie (2020). Ahead markets are likely to assist in dealing with this problem, however with the correct market design.

2. Do you have views on whether the short-term signals provided by an operating reserve mechanism or market would provide adequate incentives to deliver the amount and type of investment needed for a post-2025 NEM in a timely manner? What impact could an operating reserve have on financial markets? What are the benefits of this approach? What are the costs and risks?

Operating reserves are problematic mechanisms. Large markets work better than small markets: they are more liquid, less subject to the unilateral use of market power, and less subject to manipulation (e.g. Ellison, Fudenberg and Mobius, 2004; Ellison and Fisher Ellison, 2005). Hence economists are always weary of splitting a large market into two or more smaller markets, such as a market for operating reserves and one for spot trading.

In the short run creating new reserve markets (whatever the stated purpose) does not add capacity; instead it *removes* capacity from the (spot) energy market. The impact of removing capacity is quite clear: it increases the ability of any one generator to exercise unilateral market power because at any point in time less capacity can possibly be bid into the market. For the same reason, it also makes it easier for generators to engage in tacit collusion: the number of generators to coordinate with is smaller, the benefit of collusion larger and the penalty off equilibrium is also larger. These two effects unambiguously lead to increasing the clearing price for energy, before any kind of reserves are called upon. Furthermore, whenever they are actually required, reserves are bound to be called upon at a higher price – since the prevailing clearing price of energy is higher. This amounts to no less than orchestrated market manipulation.

In addition, the only generators that can act as reserves are dispatchable generators. Supposing a market for reserves, there are two immediate implications; (i) less dispatchable generation capacity is available in the energy (spot) market, which puts a premium on dispatchable generation, especially in periods of peak demand when prices tend to be high anyway and (ii) it increases the proportion of non-dispatchable, intermittent generation, with all the problems (stability, frequency…) that we know. These problems now may increase the demand for ancillary services, and therefore their price.

In the longer run it is more difficult to evaluate the impact of creating new reserve market(s) because it relies on anticipating entry decisions by *new* generators to *add* capacity. In a competitive market, increasing prices typically induce entry by new suppliers. However, in spite of persistent price increases since 2010, insufficient capacity has entered the market to curb this upward trajectory. Uncertainty as to government policy is often cited as the reason for this lack entry; it is well-know that supposedly risk-taking investors in fact dislike uncertainty. However, the more likely culprit is the tremendous degree of concentration in the market: controlling installed capacity is easier than controlling bidding behaviour once capacity is installed, so that any current incumbent has essentially no incentive to add capacity. Any new entrant should be weary of the reaction of incumbents upon entry, which therefore deters entry. More entry, that is, new capacity, should *not* be expected with any degree of confidence.

This likely leaves the market with higher prices only.

3. Do you have views on whether the signals provided by an expanded RRO based on financial contracts or a decentralised capacity market would provide the type of incentives participants need to deliver the amount and type of investment needed for a post-2025 NEM in a timely manner? What are the benefits of this approach? What are the costs and risks?

Capacity markets should be ruled out; they act essentially like a reserve mechanism, with all the problems highlighted in point 1 above.
The RRO is also problematic. It places obligations to contract and forecast solely on retailers, while generators are the source of most reliability problems and the source of supply shortages. It also fails to clarify whether generators are obligated to contract, while retailers clearly are. This asymmetry may induce short supply in the contract market, and correspondingly higher contract prices. Retailers are also exposed to long-term forecasting risk. Taken together these high contract prices and forecasting risk are likely to deter entry in the retail market. Finally, this obligation is designed to deal with long term adequacy, while reliability is in fact a more transient and intermittent problem.

4. Do you have views on how an operating reserve mechanism and/or expanded RRO would impact the need for and use of RERT and the interim reliability reserve if they were introduced into the NEM? What adjustments to the RERT and/or interim reliability reserve may need to be made so that they are complementary and not contradictory or duplicative?

The use of RERT appears to be independent of the problem of resource adequacy in the long run. RERT is an operating reserve mechanism, with all the problems laid out in point 2 above. In fact, RERT likely contributes to the non-informativeness of price signals: if more capacity enters and RERT is no longer activated on a large scale, prices are bound to fall – and so capacity does not enter in anticipation.

5. Do you have views on how RAMs (current or future) can better be integrated into broader jurisdictional policy priorities and programs? Should jurisdictions reflect broader policy priorities through the nature of obligations placed on retailers in an enhanced RRO or decentralised capacity market, or through the qualifying requirements for participation in an operating reserve?

In line with the comments in point 1, a combination of a more appropriate set of bidding rules that reflect dynamic costs and of a more competitive generation market are likely to deliver the correct price signals, while reserve mechanisms contribute to inflate prices.
The RRO places more obligations on retailers but is silent as to the obligations of generators, even though the market power and the behaviour of generators is largely the source of recent price rises. Generators should be made to offer energy in the forward market as an obligation, irrespective of the Reliability Instrument, as is arranged in Singapore in the form of vesting contracts, for example. The main reason is that we know, for both theory since Allaz and Vila (1993) and practice since Gans and Wolak (2007), that forward markets are pro-competitive. This pro-competitive effect stems from the fact that sellers who have already committed some fraction of their capacity for delivery through a forward contract have less to lose when lowering the spot price: the infra-marginal loss from lowering the price is smaller. Vesting

contracts are mandatory for generators wanting to participate in the wholesale market, and ask of them that they offer a specified fraction of their capacity to retailers at a negotiated price. They clearly resemble forward contracts, most of which are bilateral contracts anyway in Australia. They certainly possess the same incentive properties as forward contracts, which are known to promote competition. Thus reserving a fraction of capacity to vesting contracts can be used to both induce an active contract market and promote competition.
Note this is the *opposite* effect of a reserve mechanism. With a vesting contract, some quantity is pre-sold no matter what happens on the spot market. With a reserve mechanism, that reserve is activated only if the spot prices becomes dramatically high, and it is activated at that very high price.

B- Coal-fired generators exits -- Questions for stakeholders

1. Have we correctly identified the cost, reliability and security risks to consumers from the transition away from thermal generation?

Almost. There remains a significant risk that was left unaddressed, which may be labelled "grid-forming" risk. Thermal generators are synchronous rotary devices that naturally generate a signal wave that the grid relies on for electricity to travel at a constant frequency over great distances. In contrast, solar generation does not produce a frequency; it is frequency-following. The risk is: as thermal generation transitions out, who forms the frequency for the grid to operate? There exist technical solutions such as grid-forming inverters, for example. Mandating their installation may be necessary as more synchronous generation exits the market. While it is an additional cost to solar generation, this reflects the technical reality of this source of power. Ultimately consumers pay for this energy, and therefore these investments, whether they are imposed on VRE generators or supplied in other ways.

2. Are these risks likely to be material, particularly those relating to consumer costs?

These risks are ever present.

3. Are there additional or alternate market design approaches that will ensure the transition away from thermal generation is least cost to consumers?

Yes, an appropriate market design, on which we expand further below.

4. Should the ESB consider and develop any of the options outlined in this section further?

Only in regard to the grid-forming problem.

C- Essential system services -- Questions for stakeholders

1. What feedback do you have on the proposed provision of an operating reserve through spot market provision? How could this interact with operating reserve procurement for resource adequacy? Will such a mechanism assist manage greater system uncertainty more efficiently than current arrangements? What additional mechanisms might be needed to foster investment

needed for a post-2025 NEM? What are the benefits of this approach? What are the costs and risks?

Operating reserves have the same effect as curtailing capacity in the spot energy market; they result in higher prices and insufficient supply in the spot market, which in turn justifies the purchase of reserve capacity. However, this is looking at the argument the wrong way around, of course. This is explained in the Resource Adequacy section of this submission. This section also contains alternative options to enhance long-term adequacy; these options extend to operating reliability.

2. What are your views about developing FFR with FCAS and developing a demand curve for frequency response? Will such a mechanism help manage greater system uncertainty more efficiently than current arrangements? What additional mechanisms might be needed to foster investment for a post-2025 NEM? What are the benefits of this approach? What are the costs and risks?

At present services like FCAS are supplied by generators in a Raise event (no matter the duration) and by loads in a Lower event. Because devices can only be either a generator or a load, it is sufficient elicit from them bids to sell (either the Raise service or the Lower service). Hence there is no expression of demand until an actual event arises. It is also not clear at all *how* a demand can be expressed, short of a body like AEMO forming a forecast of frequency events.

However, the rise of storage is bound to change this reality for the simple reason that a storage unit can either charge or discharge at any point in time (up to storage constraints in either direction). That is, it can Raise or Lower at any point in time, and therefore buy or sell at any point in time. Because the *same* unit can buy or sell, its bids must be identified as a bid to buy or a bid to sell. This naturally leads to the expression of a demand schedule, as well as a supply schedule, for energy in ancillary market(s), with Raise corresponding to sell and Lower corresponding to buy.

We note also that with storage the distinction between Energy and Services becomes blurred.

3. What are your views on the proposed structured procurement for inertia and system strength by way of NSP provision, bilateral contracts and generator access standards, or through a PSSAS mechanism? Which approach is preferable, and what are the relative benefits, risks and costs? Should the ESB instead prioritise the development of spot market for or structured procurement of inertia? What are the relative benefits, risks and costs of such an approach?

There is no real replacement for the inertia supplied by rotary, synchronous generation. Developing a procurement mechanism for it as it exits seems doomed. Tasmania Hydro put forth a rule change request to sell synchronous services, however there likely is not sufficient hydro capacity across Australia to make a significant different. However storage may provide the solution; it does not replace inertia but it can address frequency variation rapidly enough before it propagates over the network. These services can be availed as FCAS services.

4. Given future uncertainties and the potential pace of change, what level of regulatory flexibility should AEMO and TNSPs operate under? What are the benefits, risks, and costs of providing greater flexibility? What level of oversight is necessary for relevant spending? Are there specific areas where more flexibility should be provided or specific pre-agreed triggers?

N/A

D- Ahead scheduling -- Questions for stakeholders

1. The ESB is interested in stakeholder feedback on the options for the ahead mechanisms we have outlined. Are there additional options? Are the options for a UCS and UCS + ahead markets fit for purpose?

An ahead market is a very good option to deal with the growing uncertainty (mostly, of supply) in the NEM. It also does much more than that. First, a day ahead market acts like a forward market, which is known to be pro-competitive. Because a fraction of the supply is bought ahead of time, the balancing spot market is smaller in volume. Therefore the inframarginal loss to price setters in the spot market is smaller; the strengthens their incentives to sell at the margin, so they bid more aggressively in the spot market.
Second, with the appropriate design, a day-ahead market can accommodate dynamic costs, or ramping costs, which characterize the technologies of all thermal generators. Indeed, Jha and Leslie (2020) estimate the production function of thermal generators and show there not only are start-up cost, but also that the marginal costs possess their own dynamics. An ahead market is also the avenue for a smoother scheduling in that it enables dispatching at the lowest cost of a long time-horizon, rather in five-minute increments. Therefore it may assist in smoothing the well-known "duck curve", which solar generation is shown to amplify (Jha and Leslie, 2020). Finally, an ahead market corresponds to the static implementation of a dynamic market and dynamic scheduling.
However, an ahead market requires careful design, precisely because it implements what is effectively a market design that deals with a dynamic problem.

2. The ESB proposes to develop the UCS tool for implementation. Do you support the UCS concept? What factors and design features should be considered for detailed development?

UCS is not sufficient to the implementation of an ahead market. More is required, including a set of bidding rules (a market design, in the sense of Wilson and Milgrom's Nobel prize) to elicit the correct bids. The current bidding rules are not adequate to deal with an ahead market. Instead the market design can borrow from combinatorial auctions to accommodate the dynamics of the technologies actually used.

3. The difference between actual and forecast residual demand leading up to real-time dispatch has been far more stable in the last decade than the difference between actual and forecast

prices ($MWh) leading up to real-time dispatch. What do you consider the drivers of this may be?

This is a simple matter of economics. Supply must match demand – and electricity demand is actually quite easy to forecast. In electricity this is a physical reality as well as a market-clearing condition. The clearing variable for the equation $S(p)=D(p)$ is the price p, which must adjust so that this equation holds. Hence p may move widely. For a long time it did not move much because supply was easy to control in the absence of VRE. With the introduction of VRE, supply is more volatile, but the clearing equation must hold, and so the clearing price p moves more widely.
For example, let demand be $D(p)=a-p$ and supply may be any of $S(p)=c+p$, $S(p)=c+2p$ or $S(p)=c+3p$ – say with equal probability; supply is increasingly elastic. This may depend on what is the technology of the marginal unit (the clearing unit), on the extent of market power of the supplier(s). A forecast may produce an expected price solving $D(p)=E[S(p)]$, so $E[p]=(a-c)/3$. However, the *actual* clearing price is any of $p=(a-c)/5$ with the most elastic technology, $p=(a-c)/3$ as forecast with the intermediate one, or $p=(a-c)/2$ with the less elastic one – all with equal probability.

An almost-equivalent perspective is to say that the marginal supply has become less elastic; that is, there are fewer market participants able or willing to supply the marginal unit. This is clearly problematic because it determines the clearing price. This phenomenon is documented by Jha and Leslie (2020) in the WA market.

<u>E- "Two-sided market" -- Questions for stakeholders</u>

1. What do you consider are the risks and opportunities of moving to a market with a significantly more active demand side over time? How can these risks be best managed?

There can be no downside to having a more active demand side if the demand-side response is correctly implemented. We note the current status of little to no demand response is an artefact of the tariff structure presented to consumers, and of metering constraints that can be easily solved. There is no reason for consumers to not be exposed to price variations in power markets; they are exposed to variations in price in all other consumption items: food, housing, fuel, travel and hospitality, even health and so on.
The risk in transitioning to a more active demand response is the creation of new rents, whereby schemes try to intermediate some kind of demand response from consumers and sell this "service" to generators or NSP. The most straightforward and cheapest way to introduce demand response is to expose consumers to price variations, that is, to restore demand elasticity.

2. What are the barriers preventing more active demand response and participation in a two-sided market? What are the barriers to participating in the wholesale central dispatch processes?

One needs to distinguish demand response from the "two-sided" market. To implement demand response from consumers it is enough to expose them to price variations. This restores demand elasticity. It requires real-time metering, as well as *informing* consumers of prices. This information may be entrusted to automated devices (computers). Consumers may also choose to delegate decision making to their suppliers (retailers or NSP). It may also not be necessary to expose consumers to the entire variation in prices, which may be very large; *some* variation may be all that is required. In other words, a partial insurance (say, against extreme price variations) may be necessary for, and beneficial to, some consumers.
A "two-sided" market (effectively a double auction) is a crucial step to accommodate the rise of storage. The reason is that, at any point in time, storage may bid to buy or bid to sell and that distinction needs to be made. To correctly accommodate storage, the design of this double auction needs to be carefully considered: the bidding strategy of a storage unit depends on its state of charge, these are *dynamic* strategies – *sequences* of decisions to buy or sell. Therefore the optimal bid at any point in time depends on both the current state of charge and the expectations of the storage unit operator. This new reality needs to be taken into account; a *well-designed* day-ahead market is appropriate to deal with it.

For more information on the economics of grid scale storage, see the pathbreaking work of Omer Karaduman (2020).

3. Do you think any other near term arrangements or changes to the market design can be explored in this workstream?

Some retailers already offer contracts to household that reflect the real-time price of energy – for example, Amber: https://www.amberelectric.com.au/. It may be worthwhile investigating why not more retailers do so, and the extent to which consumers may be reluctant to be exposed to varying prices, or misinformed as to the benefit.

4. What measures should be deployed to drive consumer participation and engagement in two-sided market offerings, and what consumer protection frameworks should complement the design?

The emergence of an active and fruitful "two-sided" market in which consumers may elect to sell their energy is quite doubtful. The reason for this scepticism is the problem of *double coincidence of wants*. The recent price time series suggests that households typically have excess supply of energy for sale in the middle of the day, precisely when aggregate demand is low. That is, there are sellers but no buyers. Conversely, when demand is high these same households consume their production, or that production turns to zero. That is, there may be lots of buyers but no seller. A market requires both sellers and buyers at the same time.
Batteries solve a lot a problem, but probably not this one. Absent buyers, a household would store its energy production and consume it later in the day – instead of drawing from the grid.

5. What might principles or assessment criteria contain to help assess whether it is timely and appropriate to progress through to more sophisticated levels of the arrangements?

As mentioned in point 3 above, some retailers already offer real-time contracts.

6. The ESB is considering combining the DER integration (below) and two-sided markets workstreams, or elements thereof. Do stakeholders have suggestions on how this should be done?

Please see point 4. above.

F- DER -- Questions for stakeholders

1. Have any key considerations for the incorporation of DER into the market design not been covered here? For DER to participate in markets, it needs to be responsive. How should the Post-2025 project be thinking about enabling responsive DER?

As mentioned in point 4. of the preceding Section ("two-sided" market), the emergence of an active and fruitful "two-sided" market in which consumers may elect to sell their energy is quite doubtful. Please refer to that Section for further details.

In the consultation document, it is mentioned that DER may take the form of controllable loads (e.g. "controllable air conditioning units", page 96; controllable load, page 97). Controllable loads are presumably taken care of via demand response. That is, if a controllable load already responds to price variations, there is little left to respond to in any form of DER. In other words, a more active demand side likely renders some of the DER workstream redundant.

2. In the next phase of the project, the ESB proposes focusing on development of a detailed DER market integration proposal. What are the most important priorities for DER market integration? We are considering combining the DER integration and two-sided markets workstreams, or elements thereof. Do stakeholders have suggestions on how this should be done?

As a matter of priority the ESB should establish whether DER is actually viable. For this, it can first study whether a market can exist, that is, are suppliers able and willing to supply when loads demand energy.

3. How can we ensure owners of DER can optimise the benefits of their DER assets over time as technology and markets evolve? How do we time reforms to manage the costs and benefits for DER owners?

It is important to ascertain whether DER is viable before parties such as households, NSP and other investors, make significant investments.

G- Transmission -- Questions for stakeholders

1. The second ISP has now been released. Do you have any comments on how its implementation can be made more efficient and timely?

N/A

2. The cost of major transmission investment projects is of concern. Do you have any suggestions on how these projects can be built for less than currently expected? Why have costs increased so markedly? Given the rising costs, are there alternative approaches to transmission project development, design and implementation which could lower the cost?

The expected returns, or cost of capital, of these projects is typically grossly overstated. The current COVID19 period notwithstanding, the cost of debt has been historically low for some years, and the revenue of these projects are essentially guaranteed; hence there is no material risk to their revenue. Therefore the cost of capital should be close to the cost of debt, and so, very low. This is not reflected in current practice.
Congestion is a transient phenomenon, and must of the congestion can be resolved though LMP. Before rushing to build more transmission capacity it may be wise to first implement LMP and re-assess congestion then.

3. The development of REZs is important for the transition underway in the NEM. Do you have any suggestions on how large-scale priority REZs can be more efficiently developed and connect into the network?

REZ and transmission investment should be jointly determined. There are trade-offs in both direction: the most attractive region for wind, for example, may be to expensive to access by transmission lines.

4. NERA Economic Consulting's modelling of the benefits of introducing transmission access reform in the NEM has been published. What do you think about the modelling and assumptions used? What does this suggest about how fit-for-purpose the current access regime is? If you are unsure of the merits of locational marginal pricing and FTRs, what other suggestions would you make about how risks of congestion might be managed by generators?

NERA's approach is sound. However they rely on a cost-minimizing approach, which itself requires that generators bid according to their short-run marginal costs. This is clearly not what happens in the NEM, where generators hold a lot of market power. However, it is pretty much all that Plexos can achieve.
The consequence is that the benefits of the transition to LMP are likely understated.

NERA projects demand to increase on the network. While total energy consumption likely will increase between 2025 and 2040, recent data shows that demand from the grid peaked around 2015 and has been declining slightly since.
The consequence is that benefits are overstated. They remain large even without growth.

The work of NERA's can be seconded by recent academic work by Katzen and Leslie (2020). In this work, they estimate the excess revenue paid out to generators under the current zonal design, compared to a counterfactual nodal design. This mispricing corresponds to approximately 9% of generators revenue. They also show that location siting of new generators (wind in SA, in this instance) is inappropriate, in that too much capacity was installed compared to the available transmission capacity. The lack of congestion pricing gives the wrong price signals to investors.

If transmission and generation were co-optimized, under a nodal market (as suggested in point 3 above), the result would *balance* transmission capacity investment and generation investment. In this wind in SA example, this would likely mean a little more transmission capacity and little less generation capacity.

5. The AEMC has released an updated technical specification paper on the transmission access reform model, alongside this report. The updated proposal provides additional information on the options regarding the design of the instruments, pricing, and trading. How well do you think the proposal would address the identified challenges?

N/A

6. What are stakeholder views on the current suite of locational investment signals? The ESB welcomes stakeholder views on alternative solutions to address the need for improved locational signalling for generators.

LMP will deliver the correct price signal for generators and storage operators to locate their plants.

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