MONASH ENERGY INSTITUTE

SYSTEM SERVICES RULE CHANGES

A reply to a consultation paper of the AEMC prepared by

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This submission:

On 2 July 2020, the AEMC issued a consultation document (SYSTEM SERVICES RULE CHANGES) seeking input from stakeholders on six specific rule-change requests, as well as a set of broader questions on market design, the general suitability of reserve markets and how to evaluate some aspects of rule change requests.

In this submission we first outline basic principles that should be used when evaluating rule-change request. We then turn to two aspects, or categories, of rule-change requests that have been submitted to (i) show that these principles do apply and (ii) more specifically discuss issues of market design. Next, we briefly assess the work required to adequately respond to these rule-change requests. Finally, we specifically reply to each of the rule-change requests documents.

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Disclaimer:

The views expressed herein are our professional opinion as experienced academics. In no way should they be construed as a policy position adopted by Monash University.

SECTION 1: GENERAL COMMENTS.

Basic Principles

Rule changes alter the incentives of market participants. When analysing the impact of changing incentives, economists rely on three overarching principles. Incentives must be designed in such way as to

1. Maximize social welfare;
2. Internalise externalities;
3. Be evaluated at their marginal benefits.

Hence rules changes should be evaluated according to these three criteria as well.

Point 1 is quite clear but often lost on market participants instigating rule change requests simply because most of them seek to maximize their (private) profits, not social welfare – or minimize system cost.

Point 2 is equally lost to market participants, for the very same reasons, and at times muddled to all. The creation of a market is not necessarily a remedy to internalising externalities, which calls to the source of these externalities to also pay for them. Hence externalities may be internalised by other means such as taxation (Pigouvian tax), specific investments (e.g. catalytic converters, carbon abetment projects, pollution filters…) as well as prices. Requesting that a market be created to correctly price the externality may assist, as long as the source of the externality, not the general public, is also the payer; such an example would be an Emission Trading Scheme. Internalising externalities is well in line with the causer-pay principle that has been embraced by the Commission, and is currently in practice.

Point 3 is a basic tenet of economics that we see at work every day. For example, in the NEM, the largest accepted bid clears the market (subject to constraints and so on) and represents also the valuation of the marginal buyer. It is the marginal benefit of a unit of consumption. Likewise, other services should be evaluated using the same principle.

Two broad categories

Several rule-change requests seek the creation of reserve markets (operating reserves, day-ahead capacity reserves). Likewise, more than one request speak to market changes to promote system strength and stability. This section groups them in these two broad categories, which it discusses in a broad sense.

A – Changes in market design: reserve markets and bidding rules.

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.

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, reserves may now 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 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 capacity is easier than controlling bidding 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.

Day-ahead markets (DAM), as suggested by Delta (specifically for reserves), exist in multiple jurisdiction – however for energy. Notwithstanding the reservations about reserve markets expressed above, DAM have merits in general. Their main benefits are first to deliver commitment to a measure of dispatch ahead of time, that is, before market conditions materialise. With less information on hand at the time of bidding, generators are less able to exercise unilateral market power. Second, DAM leave only a fraction of the dispatch subject to spot price movements; the infra-marginal quantity is largely sheltered from these short-term price fluctuations. An additional benefit, also articulated by Delta, is that DAM allow generators with ramp-up costs to express these ramp-up costs. This allows the dispatcher to optimize over a longer time horizon and deliver the lowest-cost dispatch over a time horizon rather than an instant (or a very short time window such as 5 minutes).

However, there are significant caveats to add to the introduction of a DAM. First, the full benefit of a day-ahead market is best captured in a nodal market rather than a zonal market. In a zonal market, the spot market becomes subject to strategic behaviour by generators that anticipate re-dispatch at a high (spot) market price to generate strategic congestion; this is known as the Inc-Dec game. In a nodal market this game has no object because there is no re-dispatch, and because the benefit from intertemporal arbitrage is smaller (the node, rather than the zone). There are further consequences to this practice: a worsening of congestion in the short run, and excessive investment in transmission to alleviate artificial congestion in the long run. This practice is well documented, not just hypothetical (Hirth and Schlecht, 2019; Holmberg et al. 2018, 2019). Hence a "necessary" condition of a DAM is the adoption of nodal pricing. Second, a DAM specifically for reserves can be used as a coordination device for generators to remove capacity from the spot market, with the result that spot market prices increase (as explained earlier), which would then justify the use of reserves at a high price. It is effectively creating the demand for reserves, where that demand is far from obvious today. A DAM for reserves acts in the opposite direction as a forward market for energy: it contributes to withdrawing capacity, where a forward market increases (aggregate) supply.

The introduction of a day ahead market warrants further studies to determine the best possible design and take full advantage of its features. This is very significant work. AEMO has expressed a similar interest.

B – Evaluating ancillary services: inertia, synchronous generation, frequency control

The rise of asynchronous generation induces multiple new problems that are well documented. These phenomena arise as issues nowadays largely because synchronous generation was naturally providing physical benefits as by-product of electricity generation. This is not to say it was not priced: because all generation was synchronous, the marginal benefit of synchronicity was zero.[1]

As asynchronous generation progressively *displaces* synchronous generation, the public goods (inertia and stability) provided by synchronous generators disappear. That is, it is the emergence of low-cost, asynchronous generation that induces the lack of inertia and stability. In the language of economists, each new asynchronous generator generates also a (new) negative externality. Externalities ought to be internalised and their cost borne by the party causing it, which is also in line with the causer-pays principle already adopted by the Commission, and already in force.

The consequence of that is, rather than creating new markets for ancillary services such as fast frequency control, the AEMC should ask of parties inducing inertia to decrease (i.e. asynchronous generators) to pay for this negative externality imposed on the entire system. There are multiple ways this can be achieved. One is to ask of generators connecting to the grid that they at least not deteriorate inertia; this may be achieved by using batteries to

[1] Equivalently, they were priced "in margin" and bundled with energy prices.

manage frequency fluctuations, or grid-forming inverters. Another option is to tax asynchronous generators to recover the cost of providing frequency control services, which may be availed through the market – this is akin to a Pivouvian tax. The point here is that the causer should pay, rather than the consumer. The key difference is that it may affect the generators margins only, and therefore *not* their decisions to produce and dispatch, rather than the consumers' wallet.

Synchronous generation can be evaluated in very much the same fashion, and relying on marginal benefit valuation. If adding synchronous generation (or free spinning) allows more low-cost, renewable energy to also be dispatched, *and that dispatch lowers prices*, then the value of synchronous generation is the marginal benefit. That is, the price difference over the dispatch quantity. If there is no price difference, the social marginal value is simply zero: with or without synchronous generation, the price is the same, so more synchronous generation has no object – and need not be encouraged.

The same logic also works in the other direction: suppose the clearing price path is such that synchronous generation move from online to offline, with a loss of inertia. If that loss of inertia implies curtailing low-cost energy (VRE), *and that curtailment increases the clearing price*, we can again evaluate the marginal benefit of synchronous generation at the price change over the quantity dispatched.

There may be other benefits to synchronous generation, however they are all evaluated in the same fashion: does adding or removing synchronous movement contribute to altering prices (by changing the optimal dispatch)? If it does not, it has no social value.

Work required

Multiple requests seek to introduce a market for reserves, with two consequences. One is that the introduction of a reserve market alters the available supply in the spot market; this is discussed in part A. To properly evaluate the impact of such reserve markets one should contemplate a counterfactual analysis of the market performance using historical bidding data. This work is routinely performed by IO economists; while not trivial it is well understood and can be completed in a short timeframe.

The second consequence is much deeper and much less standard. Delta's and Hydro's requests imply a very significant change in market design to introduce a notion of dynamic costs. We do know that dynamic costs matter; taking them into account would be a welcome change in the design of the market. However this is a very serious undertaking that requires expertise in market design, dynamic optimization and numerical methods. It would involves a complete redesign of the bidding process and of dispatch algorithm.

References:

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SECTION 2: SPECIFIC REPLIES.

This section addresses specific rule-change requests; there are six of them. The order follows that of the AEMC consultation document.

QUESTION 7: INFIGEN'S RULE CHANGE REQUEST, FAST FREQUENCY RESPONSE MARKET ANCILLARY SERVICE — ISSUES AND PROPOSED SOLUTION.

1) What are stakeholders' views on the issues raised by the Infigen in its rule change request, Fast frequency response market ancillary service?

   The issue at stake is well documented, namely, the progressive retirement of large, synchronous generators decreases system inertia and renders frequency control more challenging. In addition, episodes of frequency fluctuations become more frequent as VRE takes hold in electricity generation.

   However, Infigen is being disingenuous in representing the decrease in inertia as an exogenous trend that the Commission and AEMO must now deal with. As a VRE provider, Infigen contributes to in the increased VRE penetration and the concomitant exit of traditional generators capable of also supplying inertia. To be obvious, Infigen (and others) is part of the problem, for it (and others) are the source of a negative externality that is imposed on the NEM. As such, it (and others) should also supply the solution rather than asking of the Commission, of AEMO and of other market participants, to solve the problem. Tentative solutions are outlined in part B (above) of this submission.

2) Do stakeholders agree with Infigen's view that a change to the NER is required to encourage efficient provision of FFR services in the NEM following contingency events?

   If the Commission decides that FFR service should be supplied by the market at a cost to consumers, then yes, a market should be created for suppliers to enter and provide that service.

   However, this is not the only way to deal with the issue; nor is it the most efficient nor equitable. An obvious alternative is to ask of those generators (solar farms, households, wind farms) that contribute to instability, to also provide the remedy. Just like we ask of polluters to clean up or to pay for the right to pollute (e.g. emission credits) to internalize the externality they impose on others, so can we ask of intermittent generators to mitigate the consequences of their own intermittency. For example, as pointed out by Infigen, batteries can provide the very fast response that is necessary. So, an alternative mechanism is for VRE that are online (new and current) to also have sufficient battery capacity installed to mitigate the frequency fluctuations they are bound to generate. Instead of being shifted onto consumers, the cost of these batteries should be borne by VRE generators as part of their production cost. Given that most of them usually bid well below the clearing price to guarantee dispatch, this measure would have essentially no impact on the wholesale price, but only on the margin of the generators; that is, it is neutral on the incentives to produce and dispatch.

Furthermore, even if the Commission decides that FFR service should be supplied by the market, there is a natural limit to this path. In the limit, when the NEM approaches 100% renewables, who is going to "make" frequency? VRE are frequency followers: they free-ride on the frequency that is created by the rotors of synchronous generators.

Hence, for reasons of economics and engineering, the Commission should contemplate asking of VRE to also contribute to frequency control as they come online. There exist technical solutions such as grid-forming inverters. While these are still expensive, they may soon become necessary.

3) What are stakeholders' views on if there are any other issues or concerns that stakeholders have in relation to frequency control in the NEM as levels of synchronous inertia decline?

The decline in inertia is *not exogenous*; it is the result of progressive entry of asynchronous generators. The Commission, as well as AEMO, can, and should, control this decline by requesting that VRE generators mitigate the frequency control problem they induce. This will become more acute as synchronous generators keep exiting and more VRE keeps entering. In the limit, frequency may have to be set by other means than synchronous generation. It may also be considered incumbent on VRE to also provide the frequency-setting service they benefit from, and currently free-ride.

Frequency control is also not well served by current practice. It is documented that AEMO forecasts of VRE dispatch are no accurate. This leads not only to large payments into the FCAS pool by VRE, it also, and more importantly, increases the frequency of FCAS events. One part of the solution is to improve forecasting by AEMO (help can be availed), and to ask VRE generators to contribute to forecasting. The other part of the solution is for VRE generators to "firm-up" their dispatch capacity by installing fast-responding storage. This would greatly assist in frequency control, and in lowering FCAS payments of VREs – hence further justifying the cost.

4) Do stakeholders consider there are alternative solutions that could be considered to improve the frequency control arrangements in the NEM for managing the risk of contingency events as the power system transforms?

Yes, absolutely. As described in point 2) and in part B above, VRE should be compelled to take mitigating measures, or to pay for mitigation services, since they contribute to the increased instability. This may also assist them in obtaining faster connection to the grid upon entering the generation market. The AEMC and AEMO may make it a condition to be connected to the grid that VRE also provide frequency control services.

5) Do stakeholders consider that 5-minute markets for FFR ancillary services likely to be effective and efficient in the global interconnected NEM and on a regional basis?

Given the very short response times that Infigen describes a narrower time window may be necessary, especially as inertia keeps declining and frequency control episodes become more prevalent.

6) Do stakeholders consider Infigen's proposal would provide adequate pricing signals to drive efficient investment in FFR capability in the NEM?

In this reply the reader should bear in mind the caveats expressed in 2) and 4), as well as part B of this submission (above).

The pricing signals on their own are unlikely to be sufficient. First of all, Infigen has not articulated precisely who would supply these services. We know there are a handful of large batteries on hand. But the economics of grid-scale batteries are still very challenging; the main problem with them is the so-called "missing money". More accurately, batteries arbitrage prices; when large-scale batteries buy, the price increases, when they sell it decreases. The spread narrows; this is not so much a case of "missing money" than one of price impact. With Australian data, Karaduman (2020) shows the spread narrow so much that with current technology, entry is in fact not profitable. Hence, even with the creation of an FFR market, the question of *supply* of these FFR services is not solved – except if mandated by the Commission and incumbent on VRE.

7) What are stakeholders' views on, if introduced, how the costs associated with any new FFR market ancillary services should be allocated?

From 2) and 4) above it is very clear that Infigen (and others) should bear the cost of the problem they create by supplying generation that is devoid of inertia.

8) What do stakeholders consider to be the likely costs associated with establishing two new ancillary service markets for FFR in the NEM?

The real cost of remediation is the cost of supplying FFR services, and it should be borne by those causing the problem.

9) Would are stakeholders' views on how the proposed solution may result in any substantial adverse or unintended consequences in the NEM?

The solution advocated by Infigen shifts the burden of cost on consumers and possibly other market participants, while the source of the problem can readily be identified as being the increased VRE penetration (one of which being Infigen). Thus VREs should meet the cost of remediation, rather than penalising other market participants – especially consumers. There is a risk of increasing the production cost of all suppliers, including the costs of the marginal suppliers, which determine the clearing price. In contrast the marginal cost of VRE is negligible; therefore, increasing their cost by requesting they mitigate the issue of inertia is unlikely to affect the clearing price (only their margins). This is neutral on the incentives to produce and dispatch.

10) Are there specific issues with FFR that stakeholders think should be addressed in the NER as part of the establishment of markets for FFR services?

These markets may become necessary, but the in the first instance VRE should also supply frequency control service as part of their dispatch obligations.

QUESTION 8: INFIGEN'S RULE CHANGE REQUEST, OPERATING RESERVE MARKET, ISSUES AND PROPOSED SOLUTION.

1- Do stakeholders agree with Infigen that tight capacity conditions and increasing uncertainty in market outcomes are problems that an operating reserve would address?

No.
Casting aside operating reserves either removes currently available capacity from the energy market, or diverts new capacity from entering the energy (spot) market. In no way does this add any capacity to the market.
This point is discussed at greater length in part A of this submission.

2- Are there alternative solutions that could be considered to address tight capacity conditions and increasing uncertainty in market outcomes?

Yes.
There are other mechanisms to deal with the uncertainty in market outcomes. One is the contract market, in which market participants can insure against uncertain outcomes. Increased volatility may be reflected in higher insurance costs, but increasing capacity is also costly as an alternative, and it is irreversible. Promoting an active contract market is cheaper than investing in capacity.
The other avenue is to restore some price elasticity at the retail level: exposing end-users to actual market conditions is bound to tame their appetite for energy when it is expensive. Reducing consumption is much cheaper than expanding capacity. Note that restoring *some* elasticity in retail demand does not require exposing consumers to the full volatility of prices. Furthermore, not all consumers need be exposed to the same degree of price volatility. Finally, tariffs can be designed to target specifically large (domestic) users.

3- Do stakeholders consider Infigen's proposal would provide adequate pricing signals to drive efficient use of and investment in operating reserve services now and in the future?

No.
The question of entry is discussed at greater length in part A of this submission.

To paraphrase Infigen, “most of the time these reserves would be priced at zero”. The complement to this proposition, which is omitted by Infigen, is that some of the time these reserves would receive a very high price. Otherwise no entry can occur.

First, this does nothing to tame uncertainty and volatility; it likely enhances it.

Second, one technical implication is that these reserves would have to possess a rapid ramp-up rate to be dispatched in short order, when the price is high.

All in all, the price signals such reserves would need to economically enter this market are exactly the price signals Infigen complains about in their submission: highly uncertain and highly volatile spot market prices. These are also the price signals the currently high market cap delivers.

4- How do stakeholders think separate operating reserves arrangements would affect available capacity in the spot, contracts and FCAS markets now and in the future?

A longer discussion of this point is supplied in part A of this submission.

In the short run, separate operating reserve arrangements would *unambiguously reduce* capacity in the other markets (spot, FCAS).

The long run is more ambiguous and therefore more difficult to anticipate. If the price of these operating reserves becomes very volatile, it will favour peaking technologies – the caveat being that no entry may occur at all (see part A of the submission). Depending on the profitability of peaking technologies in the reserve market, versus more “baseload” technologies in the energy market, we may see less investment in the spot energy market to the benefit of the reserve market. The WA market may be a nice case study – although by no means a firm prediction. In WA, solar power displaces all other technologies during the day. This leaves a handful of generators able to operate at a fast ramp-up rate to meet the evening peak. Volatility and average prices increase. This fosters entry of peaking technology, not baseload. (See Jha and Leslie, 2020).

In any case, the creation of a separate operating reserve market introduces new opportunities for generators to arbitrage *across* these two markets rather than *within* the one energy market. Across-market arbitrage is much less effective than within market arbitrage.

5- How do stakeholders think separate operating reserves arrangements would affect prices in the spot, contracts and FCAS markets now and in the future?

A longer discussion of this point is supplied in part A of this submission.

In the short run the impact of removing capacity from the spot (and FCAS) market *unambiguously* leads to an *increase* in clearing prices, of which *all* producers benefit – including Infigen (at the expense of consumers/retailers). This immediately extends to the contract market where we can confidently anticipate an increase in any reference price for contracts in differences.

In the longer run, we return to the problem of splitting markets and introducing arbitrage opportunities across markets, rather than within markets. With less arbitrage available within market, prices can be expected to increase.

If prices increase sufficiently in the spot and contract market, this *may* be enough to spur entry in the spot market. Entry in the spot market then makes the reserves market effectively redundant.

There remains a risk that prices become more volatile in the spot and the reserve market, which would incentivize entry of peaking technologies rather than baseload. This may be especially true as traditional baseload exits the market. Again, if this does trigger entry (in the spot market), then this operating reserves market runs the risk of becoming redundant.

6- How could the design of an operating reserve market (e.g. criteria for eligible capacity) best support competitive outcomes both in the operating reserves market but also energy and FCAS markets?

It is very clear that creating a separate operating reserves market is not designed to be competitive – quite the opposite. It is designed to further tame competition in the spot market.

7- What are the factors that should be considered when seeking to set and procure efficient levels of operating reserve?

The main issue, as discussed in part A and in points 1) to 6), is the substitution from the spot energy market to a reserve market. The effect of such a substitution is to increase scarcity in the spot market, and to (artificially) make reserves all the more valuable.

A more accurate forecast of both demand and supply conditions (i.e. including weather forecast) may be a better investment than creating a reserve market.

8- Would Infigen's proposed operating reserve market result in any substantial adverse or unintended consequences in the NEM?

Yes. A longer discussion of this point is supplied in part A of this submission.

Infigen's proposal amounts to removing capacity from the energy market and park it in an operating reserve market that is to be accessed only when the price is high enough (equivalently, when approaching the capacity constraint). Removing capacity renders the unilateral exercise of market power more lucrative, and also facilitate coordination in bidding (market manipulation) because there are fewer generators at the margin. As a result prices can confidently be expected to increase, to the benefit of all generators, including Infigen.

There is also scope to alter the pattern of prices to favour peaking technologies.

9- What are the costs associated with establishing an operating reserve market in the NEM? If introduced, how should these costs be allocated?

The real cost is the opportunity cost of removing capacity in the energy market. Upon request this could be quantified under alternative scenarios.

10- What kind of incentive/penalty arrangements would be necessary to be confident the operating reserves procured are available when needed?

This speaks further to the problem of removing capacity in the spot market: there is always a risk that reserves be unavailable when called upon, which would drive prices further up. This problem also plagues capacity markets, and in fact operating reserves are not very different from capacity markets.

In principle, penalties could be part of the agreement that reserve suppliers enter into when participating in this market. In practice history has shown it is difficult to implement these penalties; they are often contested in courts, the burden of proof may be too high, some parties may be judgement-proof and so on.

When penalties fail, economic rents are the alternative solution. Very superficially, paying the energy price for reserves to operate may not be sufficient to trigger operation: by waiting just a bit longer to turn on, the price may increase and the generator(s) would benefit. (Note too that in this case, that capacity is better left available in the energy market.) The solution is then to pay a premium on the spot market price at time t, the value of which is equivalent to waiting for some time Δt. Note this makes operating reserves more expensive that the spot market, and it likely is better to simply keep the capacity in the spot market.

QUESTION 9: DELTA'S RULE CHANGE REQUEST, INTRODUCTION OF RAMPING SERVICES, ISSUES AND PROPOSED SOLUTION.

1) Do stakeholders agree with Delta that price volatility that occurs when dispatchable generators ramp through their energy bid stacks in response to predictable, daily, high rates of change from solar ramping up and down is a problem that needs addressing?

Yes, it is a problem that must be addressed and that may require a significant reorganization of the market.

There are two parts to this problem. One is the very predictable diurnal schedule; there is simply no sun past sunset, and other generators must be available to produce energy at that time. The real problem is that, when it is available, solar generation displaces most other forms of generation because of the merit order effect. These displaced generators then have to (sometimes rapidly) ramp up when solar power becomes (predictably) unavailable. This makes for both higher volatility in prices and higher mean prices because few generators can respond fast enough, and so can exercise unilateral market

port. This phenomenon is well documented by Jha and Leslie (2020) for the WA market; there is no reason for it to not be similar in the NEM.
The second problem is less predictable and has to do with the unexpected availability of VRE, especially solar energy, during the day.

2) Do stakeholders think that a new raise and lower 30-minute FCAS would address the price volatility at these times? Are there alternatives that could be considered to address this problem?

Not completely.
The proposed solution may address the second issue, namely, the unexpected shortfalls in VRE. There are also alternative solutions to this problem. A reasonably obvious alternative is for market participants to invest in more accurate weather forecasting to better anticipate variations in wind and solar output. Both VRE and scheduled generators have an interest in better forecasting the weather. Any improvement in forecast contributes to narrowing the window of unexpected events.
It is unclear why a new 30-minute FCAS market is necessary. If the volatility is so large that this new FCAS is triggered, that same volatility should be expressed in the energy market and elicit a response: if a dispatchable generator can respond in the 30-minute FCAS market, they can also respond in the energy market. Furthermore, (i) protection against volatility can be purchased in the contract market; and (ii) this proposal has the same effect as creating a reserves market: it removes capacity from the energy market, with the consequences we understand well (see again part A of this submission).

The creation of a new raise-lower 30-minute FCAS is not an appropriate solution for the completely predictable cycle in VRE that owes to the sun setting every day. This is probably better addressed by a complete redesign of the market rules to allow the expression of dynamic costs – that is, start-up and ramp-up costs.
The problem at present is that the market design ignores the explicit expression of ramp-up costs; it prices them implicitly in the energy price. When all generators possess the same technology and face similar ramp-up costs, this is not a problem. But nowadays that is not the case; thermal generators face varying ramp-up costs, VRE face essentially none. The result of this new heterogeneity is that, when pricing and re-pricing energy every 5 minutes, the market favours generators with no ramp-up costs and displaces those that must ramp-up. This goes on until solar energy is no longer available; at that time ramp-up must occur, it is costly and favours those thermal generators that can ramp-up rapidly; they are also the expensive generators.
Allowing for an expression of ramp-up costs requires eliciting bids from multiple periods, over which the dispatch engine can optimise to deliver the lowest-cost dispatch over an *entire day* rather than over a 5-minute interval. This would a profound change in the market design, which paves the way for a day-ahead market (see also part A of this submission). Such a change in market design may have significant implications for investment in VRE.

3) Do stakeholders consider Delta's proposal would provide adequate pricing signals to drive more efficient use of and investment in ramping services than existing price signals and information provided through the PASA and pre-dispatch processes?

No. This point is largely articulated in 2) above and in part A of this submission.

4) How do stakeholders think a separate 30 minute ramping product would affect available capacity in the spot, contracts and FCAS markets now and in the future?

Capacity would be affected in the same way as if creating a reserves market – see Question 8 above (Infigen Reserves Market) and part A of this submission.

5) How do stakeholders think a separate 30 minute ramping product would affect prices in the spot, contracts and FCAS markets, now and in the future?

Prices would be affected in the same way as if creating a reserves market – see Question 8 above (Infigen Reserves Market) and part A of this submission.

6) How could the design of a ramping FCAS product (e.g. criteria for eligible capacity) support competitive outcomes both energy and FCAS markets?

It could not; it is not designed to foster competition but to hamper it – see Question 8 above (Infigen Reserves Market) and part A of this submission.

7) What are the factors that should be considered when seeking to set and procure efficient levels of ramping services?

Besides factors already mentioned there is a technical point worth mentioning. Ramp-up implies a time horizon; the problem then becomes dynamic. This is a completely different exercise than linear programming.

8) Would Delta's proposed new 30-minute raise and lower FCAS products result in any substantial adverse or unintended consequences in the NEM?

Yes. A longer discussion of this point is supplied in part A of this submission.

Just like Infigen's proposal, Delta's suggestion amounts to removing capacity from the energy market. Removing capacity renders the unilateral exercise of market power more lucrative, and also facilitate coordination in bidding (market manipulation) because there are fewer generators at the margin. As a result, prices can confidently be expected to increase, to the benefit of all generators, including Delta.
There is also scope to alter the pattern of prices to favour peaking technologies.

9) What are the costs associated with establishing new 30-minute raise and lower FCAS products in the NEM? If introduced, how should these costs be allocated?

   The real cost is the opportunity cost associated with removing capacity from the energy market to create a new, separate FCAS services. As suggested above there are alternatives to this option.

10) What kind of incentive/penalty arrangements would be necessary to be confident the new 30-minute raise and lower FCAS products procured are available when needed?

   Please see the same point Question 8 above (Infigen Reserves Market).

QUESTION 10: DELTA'S RULE CHANGE REQUEST, CAPACITY COMMITMENT MECHANISM FOR SYSTEM SECURITY AND RELIABILITY SERVICE, ISSUES AND PROPOSED SOLUTION.

1) Do stakeholders agree with Delta that there is an increasing risk that capacity capable of providing reserves or services may not be available at times when the power system may need them to respond to unexpected events because of increasing incentives to decommit?

   In a broad sense, yes.
   This request, and the case it makes, are the corollary to QUESTION 9—also from Delta. As VRE, and especially solar energy, displace thermal generators, and especially coal generators, because of the merit-order effect, there is distinct risk that they will turn off or outright decommission. There is little doubt that this phenomenon has precipitated the exit of some generators in states like South Australia. For some further information see also the work of Jha and Leslie (2020).
   This has consequences for system strength, inertia, and the ability to respond to frequency events. How to value the contribution of a generator to these services is not clear from the request. This also has consequences for the exercise of market power by peaking generators, which are the only ones left when baseload is not committed and when the sun has set.

2) Do stakeholders think that a mechanism to commit capacity one day ahead of time would deliver the reserves or services needed? Are there alternatives that could be considered to address this problem?

   It is not at all clear that a capacity market for reserve services would deliver the services intended, or at least stated. Capacity markets have proven to be very expensive (see, for example, WA). Day ahead markets can display many good features, but also be plagued with problems and subject to gaming (see part A of this submission). Finally, reserve markets display many undesirable properties (see again part A of this submission); in particular, by design, they remove capacity from the energy market, which induces higher clearing prices.

There is a distinct risk with Delta's proposal that thermal generators be paid to provide reserve services with this clearing price becoming a floor in the energy spot market. Furthermore, that reserve market price may be easily manipulated among a small number of generators. In addition, with capacity in the energy spot market being reduced, that spot market clearing price is also likely to rise.

There are alternatives to the solution suggested by Delta. As a preamble, any alternative (including Delta's proposal) involves redesigning (at least some of) the bidding rules. It is important then to consider the impact of any one rule change on the entire market. An alternative consists in altering bidding rules to allow for generators to express their ramp-up costs – this was mentioned in QUESTION 9 above.

3) Do stakeholders consider Delta's proposal would provide adequate pricing signals to drive more efficient use of and investment in reserves and system services?

This is very doubtful. There are significants risks that the market be gamed. See point 2) above.

4) How do stakeholders think Delta's capacity commitment payment would affect available capacity in the spot, contracts and FCAS markets now and in the future?

In the short run it is unambiguous that capacity in the spot (and other) market(s) is bound to decrease.
In the longer run this is more difficult to predict in that any meaningful increase in capacity requires investment and entry in the market. As has been expressed elsewhere in this submission, entry is not a foregone conclusion. It depends on whether the *market structure* is conducive of entry. At present the incentives for entry are very weak, mostly because of the tremendous concentration in the generation sector, and the inability of new generators to find counterparties in the contract market.

5) How do stakeholders think Delta's capacity commitment mechanism would affect prices in the spot, contracts and FCAS markets now and in the future?

As mentioned elsewhere in this submission, removing capacity from the spot market to create a day-ahead reserve market will likely lead to price increases. There are three reasons for this. The first one is that with fewer generator bidding in the spot market, each bidder can exercise unilateral market power more easily. The second one is that, with fewer bidders, collusion (coordinated bidding) is both more profitable and more easily sustainable. The third is peculiar to this market structure: the day ahead market can essentially act as a price floor in the spot market. This is the opposite effect from the forward market (see Allaz and Vila, 1993, and many others since).

These phenomena are somewhat connected to the question of entry. Of course, higher prices beget entry. However a strategic player should also anticipate the reaction of collusive incumbents, who have every incentives to render entry unprofitable by decreasing prices upon entry. In addition, new players will continue to find it difficult to find contract counterparties, which also hampers entry.

6) How would a capacity commitment mechanism and payment affect entry, exit and competition in the NEM over the short and long term?

As alluded to in 5) above, a day-ahead capacity commitment mechanism stifles competition in the NEM in the short run. Of course, it does nothing to spur entry in the short run. It may slow down exit of baseload generators, but it is unlikely that there continued presence in the NEM under this design keep a lid on prices. The reason is that this capacity would be unused, so not bid in the spot market, and may furthermore act as a price floor in the spot market.

It the long run this mechanism offers no guarantee of more entry, which is a major condition to lower prices.

7) What are the factors that should be considered when deciding how much capacity to commit ahead of time?

Given bids by generators, AEMO's task would be to balance the clearing price in the ahead reserve market to guarantee the committed generators operate (MSOL), with the expected price in the spot market. The more reserves are committed, the lower the remaining capacity to supply energy in the spot market, and the higher the spot price. A high spot price may call for reserves to be used. It is apparent that reserve suppliers effectively create their own demand for reserve services by withdrawing from the spot energy market and bidding in the reserve market.

Strategic players would therefore take advantage of this mechanism to bid more reserves and drive up the spot price. If reserves are purchased at the spot price, they may receive an artificially high price. This is particularly prevalent in periods of high volatility. Note that no supply is added along the way, but that prices increase.
In periods of low demand, a positive reserve price acts as floor to the spot market: if anticipating a low spot price, a generator should bid its capacity in the reserve market. We revert to the issue of splitting market – see part A of this submission.

8) Would Delta's proposed capacity commitment mechanism result in any substantial adverse or unintended consequences in the NEM?

In all likelihood it would increase prices and not result in more entry, as outlined above.

9) What are the costs associated with establishing a capacity commitment mechanism in the NEM? If introduced, how should these costs be allocated?

An important aspect of this question is, if AEMO procures commitment reserves (that are not dispatched) at some positive price, how should the cost of these reserves be recovered? Who should be charged? Delta's proposal is silent to this point.

If reserves are dispatched they are clearly paid for by the entities purchasing them. However if they are not, their cost is not as easy to allocate as, for example, frequency control services that are attributable to VRE, especially when a deviation can be traced to its source. This speaks in fact to the purpose of these reserves, and to the adequacy of the suggested mechanism: who truly benefits from such a reserve market? One avenue is to recover these costs from market participants through either a tax on energy that is traded, or a spread (bid-ask prices). But that is not the correct way of recovering these costs; a tax, like a spread, affects incentives at the margin. In addition, who of all market participants truly benefits?

The inability to find a satisfactory recovery scheme also speaks to the inadequacy of the mechanism. In the alternative mechanism we suggest (a complete day-ahead market for energy, with intertemporal optimization), cost recovery is not a concern.

10) What kind of incentive/penalty arrangements would be necessary to be confident that the committed capacity would be available throughout the commitment period and/or when called upon?

Please see the same point Question 8 above (Infigen Reserves Market).

QUESTION 11: HYDRO TASMANIA'S RULE CHANGE REQUEST, SYNCHRONOUS SERVICES MARKETS, ISSUES AND PROPOSED SOLUTION.

1) Do stakeholders consider this rule change proposal presents a viable model for the provision synchronous services?

No.

There are many flaws to this specific request. It overvalues synchronous service. It over-simplifies the dispatch problem, which is technically very challenging.

a) Could this proposed model be used to provide the essential levels of system strength (and / or inertia and voltage control) needed to maintain security and the stable operation of non-synchronous generation?

I doubt it because Hydro is the only large generator that can provide meaningful synchronous services at short notice. Other synchronous generators all have to burn fuel and ramp-up to start spinning. This request very much appears to be designed for Hydro's sole benefit.

b) Could this proposed model be used to provide levels of system strength (and / or inertia and voltage control) above the essential level required for security?

This is unlikely. Most spinning generators, except hydro-energy generators, are in fact unable to respond rapidly enough to supply the service.
In addition, why would one want to pay for extra service when system strength is not a binding constraint (i.e. *above* the essential level required for security)?

2) Do stakeholders consider that the creation of a synchronous services market could have any adverse impacts on other markets in the NEM? If so, what would these impacts be?

As the proposal stands there is an adverse impact in that loads may be asked to pay more than the social value of the synchronous intervention – please see details below about the social value of the synchronous service, as well as part B of this submission.
Beyond that there can only be limited distortionary effects because these generators sit offline if not providing synchronous services. There is one potential upside for thermal generators, which is to warm them up enough to be spinning and so may cut down ramp-up time when they start bidding to produce energy.

3) Would the proposed model set out in the rule change request efficiently price and allocate costs for synchronous services in the NEM?

No.
The proposal is silent as to the cost of offering SSG services, however we know they are very low. In fact, it may even be free: whenever Hydro's dams reach capacity, water must be released even if it does not produce. At that time, the rotors may as well spin.
It is not clear to me why the proposal suggests a dual settlement as described. In principle services should be compensated at their marginal value. The marginal social value of an SSG that induces (through dispatch of cheaper generation) no change in the clearing price is zero. To use the numbers that Hydro suggests, the marginal value of a an SSG that decreases the price from $100/MW to $99/MW is $1/MW – not $50 as bid.
It may not be easy to keep track of price variations with and without SSG but that is the correct approach. Given a bid stack, the dispatch can always be replicated and run as a counterfactual dispatch to compute the counterfactual clearing price (say, without SSG) to evaluate these price differences.
Even if the chief concern is system security, for example, achieving that security can be measured by the dispatch choices. Therefore one can always measure the social value of the SSG by the change in clearing price that a variation in dispatch induces thanks to the SSG.

This is discussed at greater length in part B of this submission.

4) Do stakeholders consider the model set out in the rule change request would be capable of sending price signals sufficient to encourage new investment in synchronous capacity?

Please see 3) above and part B of this submission. At $1/MW (which is the correct valuation in the example) the incentives are not very strong. However, this depends also on the dispatch volume that is affected; that is, even though the marginal social value (the price difference) may be small, the volume that it affects may be large. Further, thermal generators may benefit because they may use the opportunity to ramp up and offer inertia at the same time.

A lot more work is required to correctly evaluate the incentives this proposal may generate.

5) Do stakeholders consider the rule change provides an appropriate incentive mechanism for existing synchronous generators to make operational decisions to provide synchronous services?

The proposal seems to suggest an incentive mechanism that is appropriate for Hydro to elect to come online on terms that it decides when it otherwise chooses to earn no revenue from generating energy.

These could also extend to other synchronous generators, in particular thermal generators ramping up and offering inertia simultaneously, with the caveat that the correct valuation be used.

However, embracing the mechanism as proposed is not socially optimal. The correct benchmark is to measure the social value of the service. That value is commensurate with the change in price it induces; it may be zero.

6) Do stakeholders consider the rule change provides the appropriate locational signals for the provision of synchronous generators to provide synchronous services?

Providing geographically relevant locational signals requires the adoption of locational marginal pricing.

In light of the comments in 3) and 5), the price signals this rule changes suggests appear to be inappropriate.

7) What do stakeholders see as the primary opportunities / limitations of the mechanism as proposed by Hydro Tasmania?

As suggestive of the comments in 3) and 5) above, the main limitation is that the mechanism is very self-serving and it likely overstates the social value of the synchronous generation intervention.

This is not to say this proposal is completely devoid of merit. There may be value in getting a synchronous generator online, especially for example, in a ramp-up phase. Of course then the marginal value of energy is high and they elect to come online anyway. In other instances, for example, in case of high instability, the marginal value need not be the difference in energy prices but the VoLL. However this needs to be further studied by the proponents of the rule change.

8) Would the model proposed in the rule change request enable effective competition in the market for the provision of synchronous services?

This is unlikely.
Hydro is likely the only supplier that owns generators large enough to make a material contribution to inertia in a short timeframe that is meaningful for the NEM. Other large synchronous generators are thermal generators, which cannot act in the short run. This leaves Hydro in a monopoly situation, bar for the role of the Snowy generators.

9) What suggestions do stakeholders have in relation to the first order changes that would be required in NEMDE to facilitate this proposal and any second order changes that may be required as a result of this rule change proposals' implementation?

a- The changes in the constraints that are requested are as not as simple as suggested. Constraint B1 in Appendix B is a ***dynamic*** constraint: on the left-hand side (LHS) one has the *contemporaneous* SSG_{peaker} term, on the RHS the *prior-period* SSG_{peaker} target. This implies that for each dispatch interval, the program has to keep track of past targets. It opens the door to a problem of intertemporal optimization: the "dispatcher" may not just optimize over a single dispatch target, but over an entire path of targets. This problem does not exist in NEMDE at present because it ignores all dynamics. This problem is no longer a "simple" problem of linear programming.

All sort of issues arise in a dynamic problem: intertemporal optimization is not easy, the paths of SSG_{peaker} may be subject to constraints, the state space becomes very large, paths themselves may be subject to manipulation and so on.
Even if the proposal has merit, this seems to be a much larger hurdle than suggested by Hydro. It is incumbent to Hydro to supply more than a couple of worked examples off the cuff to make its case. It is a very complicated problem.

b- The scenarios supplied by Hydro are not satisfactory; they are completely ad hoc and illustrative rather than supportive of the proposal. For example, scenario 2 suggests the SSG to be offline and bid only $50 when the clearing price is $100. I strongly suspect that if the energy price is $100, the synchronous provider will not bid $50 but rather $100, or close to it. In this case, under the Hydro proposal, the synchronous provider does not collect $50 but $100 and loads are charged $99.8 rather than the $99.4 suggested. This now becomes a negligible gain. In addition, it incorrectly values the social benefit of the SSG – see point 3) above and part B of this submission.
Perhaps more importantly, because the scenarios are *not* equilibrium model outcomes but arithmetic exercises, we have no idea whether the clearing price should move from $100 to $99 when more wind is included in the generation mix. Wind bidding at $0 is clearly not the marginal supplier, so more wind may not move that margin, and the clearing price

may not move at all. In this case there is no benefit to loads – only to Hydro. But then we know that social value is zero – again, see part B of this submission.
Here too some serious work is required to at least establish whether getting the SSG online at least moves prices. Otherwise the point of supplying SSG services is moot.

QUESTION 12: TRANSGRID'S RULE CHANGE REQUEST, EFFICIENT MANAGEMENT OF SYSTEM STRENGTH ON THE POWER SYSTEM, ISSUES AND PROPOSED SOLUTION.

1. Do stakeholders consider that TransGrid's approach address all issues related to system strength currently experienced in the NEM?

   Although it is difficult to say whether this approach will address "all" issues related to system strength in the NEM, it is definitely an initiative that can improve and streamline many generator connection processes. With the increasing number of power-electronic-connected inverters in the NEM, we will face new issues in future that we are not facing now. However, lack of a coordinated approach for system strength will create more problems in years to come.

2. Do stakeholders consider that a system strength planning standard met by TNSPs would effectively and pro-actively deliver adequate system strength?

   A system planning standard will definitely result in a better deployment of assets if coordinated and optimised. Yet again, it is difficult to predict what exactly will happen as the number of inverter-based generation (with different internal control strategies unknown to the grid operators) is rapidly increasing. However, if TNSPs become responsible for providing grid strength, this may motivate manufacturers not worry about providing such services via internal controllers of their inverters, which in turn, helps avoiding unwanted interactions among inverters. It is also noticed that the proposed approach by TransGrid is a technology-agnostic approach, which paves the way for more promising grid strengthening assets such as grid-forming inverters.

3. Do stakeholders consider TransGrid's proposal will provide useful and timely locational and financial signals to new entrants?

   This is likely. Guaranteeing a given system strength by the TNSP will significantly encourage the developers to consider more investments and develop new farms as they don't have to worry about various problems during and even after connecting their inverters. It is in particular important in areas where recently some farms' outputs have been cut due to system strength concerns. Additionally, this will facilitate the GPS studies, which in turn expedites the renewable energy uptake.

4. Do stakeholders agree that the 'do no harm' obligations should be removed? If so, do stakeholders consider an alternative mechanism is required to regulate or incentivise the minimisation of a new connecting generator's impact on the local network and proximate plant?

   It is probably best to not remove "do not harm" obligations completely. Regardless of system strength, adjacent inverters need to work with other assets without any adverse interaction on each other or without causing any oscillations in the NEM. Hence, although maybe the existing "do not harm" obligation might not be needed, another form of such an obligation must be in place.

5. What are stakeholder's views regarding generators' being required to make a financial contribution for provision of system strength services?

   It makes sense to charge generators a yearly or monthly connection fee based on their size and location to cover various expenses. It is also well in line with the causer-pay principle and the principle that externalities should be internalised. However, depending on the grid strengthening assets to be put in place, this may not be necessary. For example, grid-forming inverters not only can provide system strength but also can provide some other ancillary services for which they will be paid. This can provide the revenue needed for their installation and running costs (although running costs are not too much for grid forming inverters). Hence the approach should be flexible enough to accommodate a diversity of situations.

6. Would stakeholders be supportive of the ownership of existing private system strength assets being transferred to TNSPs, as suggested in TransGrid's rule change request?

   This, if handled properly, most likely can result in a better management of these assets and also help reducing the connection fee for generators (as per Question 5). This can be seen similarly to the transmission lines which are owned by the TNSPs, as these assets enable generators to get connected to the transmission networks seamlessly and export their maximum power.

7. Would the proposed, TNSP-led solution to system strength result in any adverse or unintended consequences for market participants in the NEM?

   The only difference between this approach and the current approach in terms of impacts on the NEM is that in the proposed solution, the grid strengthening assets will be coordinated and optimally allocated, which can only improve the situation rather than harming the system.

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