Ms Jess Boddington
Australian Energy Market Commission
Submitted online to www.aemc.gov.au

8 November 2019

Dear Ms Boddington,

COGATI Proposed Access Model – Discussion Paper EPR0073

ENGIE Australia & New Zealand (ENGIE) welcomes the opportunity to contribute to the development of the COGATI proposed access model.

ENGIE is a global energy operator in the businesses of electricity, natural gas and energy services. In Australia, ENGIE has interests in generation, renewable energy development, and energy services. ENGIE also owns Simply Energy which provides electricity and gas to more than 720,000 retail customer accounts across Victoria, South Australia, New South Wales, Queensland, and Western Australia.

ENGIE is an active member of the Australian Energy Council (AEC) and has contributed to, and fully supports the Councils submission. In addition, ENGIE emphasises the following concerns with the access model design:

1. Treatment of scheduled and unscheduled generation in the access model is problematic as is the application of the volume weighted average price (VWAP). Mis-priced signalling to generators and loads in a given region/sub region based on classification of participants warrants further examination. As proposed, the model risks perpetuating existing NEM design flaws and associated technical issues.
2. Consideration of duration of financial transmission rights (FTR) for new and existing projects is extremely important to better coordinate transmission and generator investments and to manage risks.
3. Detailed cost benefit analysis is needed and returns on investment should be quantified.
4. Market interventions will impact the proposed access model and need to be fully assessed.
5. Consistency of the access model with market design is essential. The access model is unlikely to be suitable for other than the current energy only market.
6. Incentives and penalties for network performance are necessary to maximise benefits of the access mode.

1. Scheduled/unscheduled generation/loads and the VWAP

The existing National Electricity Market (NEM) trading arrangement has a number of design shortcomings leading to technical challenges and economic inefficiencies. These stem mainly from mis-priced energy signals and unpriced services necessary to system operation.

To illustrate, consider a case of excess generation in a region, when market loads and generation receive a low or negative spot price. The price signal encourages regional generation to reduce, and market load to increase. However not all load and generation are exposed to the same market signal. At the same time retail load is on a fixed price and doesn't see the low/negative spot price signal. Behind the meter generation on a feed-in tariff (FIT) is incentivised to keep generating. Even some larger distributed generation may be on a retailer contract and is not encouraged to reduce generation. Load under retail tariffs is also blind to respond to the low/negative spot prices.

The price signals between market and non-market participants are thus inconsistent, are diametrically opposed to the spot market and are economically inefficient. This situation places an added requirement on scheduled generation to reduce output and often presents technical challenges for AEMO (ie regulation, minimum generation etc).

The five-minute pricing will do nothing to encourage price sensitive load/generation response from participants that are not already exposed to spot price.

The problem becomes even more acute when considered in an intra-regional constraint setting. In this case generators behind the constraint are incentivised to generate by the regional price, even if there is excess generation behind the constraint. Similarly, market loads behind the constraint are disincentivised from increasing their load by the high regional price which doesn't reflect conditions in their vicinity.

When load shedding occurs, extreme high prices are set at the regional reference node (RRN). At the same time there maybe excess generation in an intra-regional constrained sub-region where market floor price is set in dispatch. Such strong mis-priced signals have caused system security challenges for AEMO in operating the market and create risks for participants.

The AEMC proposed access model goes a significant way towards restoring efficient pricing to scheduled and semi-scheduled participants.

Unfortunately, this is only a partial solution as unscheduled and retail participants are excluded from the model. Exclusion of these participants from efficient market signals remains a significant issue. This group of participants is likely to continue to grow in importance as the level of distributed energy resources (DER) continues to increase over time and conventional thermal generation decreases. It should be noted that the level of DER increases in all of AEMOs current forecast scenarios.

Some DER is small in size and maybe located behind the meter. Aggregators may provide some load/generation management services on behalf of these participants. However, it is highly unlikely to be the case in all network locations. In addition, the cost of aggregation will significantly diminish customer incentives to participate, this was also evident in related work published by the AEMC in relation to DRM.

As a matter of principle, market design must not rely on aggregators to correct deficiencies of mis-priced signals.

It is paramount that efficient market price signals are available for energy and for all services sought by the market to operate effectively.

ENGIE shares the AEMCs expectation that over time the NEM is likely to transition towards a two-sided market; the original market design expectation, as demand side resources become more responsive to wholesale market prices.

The current move to five-minute settlement and locational pricing are important refinements seeking improvement in economic efficiency. These price signals must be made visible to all participants in the market irrespective of their classification to facilitate a wide as possible response and to encourage distributed decision making. Retail customers mustn't be excluded as technology enables a range of behind the meter services by automating responses to market signals without need for an aggregator.

Such local signals need to be expanded to include a range of ancillary services, some of which remain unpriced in the current market. These deficiencies must be addressed as a matter of priority to avoid on-going AEMO directions, and consequential market distortions, which are becoming more frequent over time.

The proposed application of volume weighted average pricing (VWAP) distorts local prices to participants and, as such, fails to provide an efficient price signal to encourage local response. In effect, this is a very similar outcome to the existing NEM and resultant mis-priced signalling as articulated earlier in this section. In addition, depending on the proportion of volumes of energy in the proposed categories, this price distortion maybe very significant where the price signalling is compromised at the regional and sub-regional level.

Outcomes sought:

1) *Ensure that market signals are:*

    a) holistic by covering the full range of services needed by the market

    b) representative of local conditions to enable all market participants to respond

    c) inclusive of non-scheduled entities.

2) *Abandon the VWAP concept on the grounds of economic efficiency and the need to accommodate increased volumes of small DER in the future.*

2. FTR duration and transitional arrangements

Projects in the market are long lived and it is important to consider access to transmission in this context. The current proposal calls for relatively short duration for the FTRs and participants face the risk of re-contracting the FTR in terms of availability and price. To reduce the transmission access risk over the life of a project, the FTRs would need to be made available over the asset life. In this way a project proponent can use the FTR cost as another form of locational signal (others considerations may be resource yields, distance from ports, road access, geology, etc).

If longer FTR duration can be achieved, the proposed access model will come close to meeting the stated objective of optimising generation and transmission development, as the cost of generation and transmission will be assessed together.

The transitional arrangement should be based on a similar principle and cover the remaining life of an asset. Assets once built, cannot respond to locational signals and relocate. Forcing existing assets to participate in the FTRs would simply place a tax on existing assets and increase their costs of doing business.

Such long duration FTR allocation would not compromise economic efficiency due to locking in the FTRs for the remaining asset life. Should economic circumstances change, the existing project may choose to close and sell the FTR back to the market.

In summary, FTR must have a long duration, be tradeable in a secondary market and be restricted to physical assets to avoid speculators.

Outcomes sought:

1) *Ensure that the FTRs are available for long time durations, out to the life of an asset.*
2) *Design a transitional arrangement where the FTRs are allocated to existing generators for the remaining life of an asset.*

3. Cost benefit considerations

The Access Model design discussion paper makes several assertions regarding the potential benefits of such a reform. These are as follows:

- Page v Paragraph 36 … These arrangements should improve **investment certainty** for generators and storage and may **reduce their cost of capital** in the longer term.…
- Page v Paragraph 37 …This should also improve participants' willingness to offer energy contracts, improving **contract market liquidity**, both within regions, but also across regions.

In its current form, the access model isn't considered to increase investor certainty hence the claim of reduced cost of capital is unfounded. If the FTRs were to be fairly priced, the holder of the FTR would be expected to recover their cost over the life of the instrument. The instrument would serve to reduce volatility of outcomes along the way but the expected value of the project should not change.

The improved contract market liquidity is questionable, as a contracting arrangement using SRAs (settlement residue auctions) across multiple regions was contemplated at market start but failed to be used by participants.

In addition, the access model must be fully costed, return on investment quantified and the payback period determined.

Outcome sought:

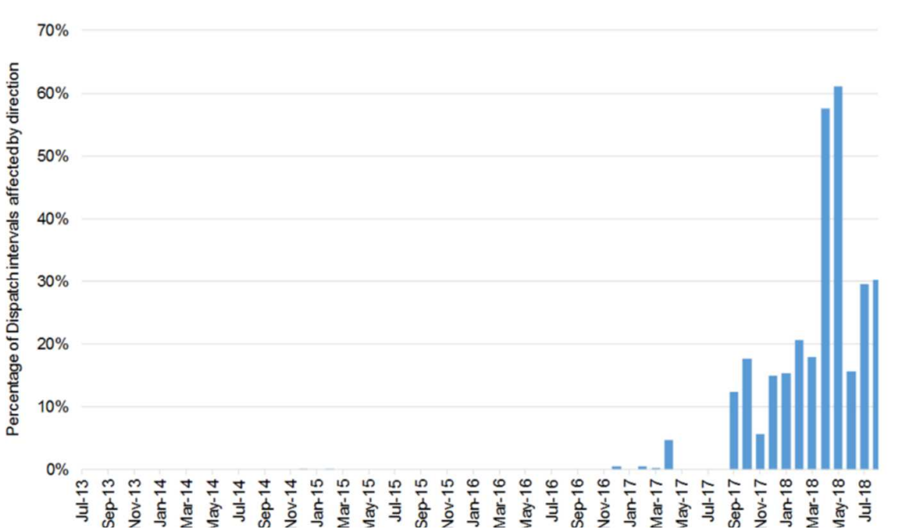
1) *The AEMC needs to provide a detailed rationale for such claims and where possible use modelling (or simulation using participants) to substantiate any assumptions regarding participant behaviours*

2) *Implementation costs must be quantified and include changes to participant IT systems.*

3) *The return on investment and payback period should be quantified for this initiative.*

4. Market interventions

Over time conventional generation is being progressively displaced by DER and this trend is expected to continue. Due to known deficiencies in the current market design, there is an increasing use of direction by AEMO to provide services outside the market. The following figures; sourced from the Energy Security Board 2018 report titled “The health of the national electricity market” and the AEMO “Options for NEM market design” September 2019 paper illustrate the historical frequency and number of market interventions.



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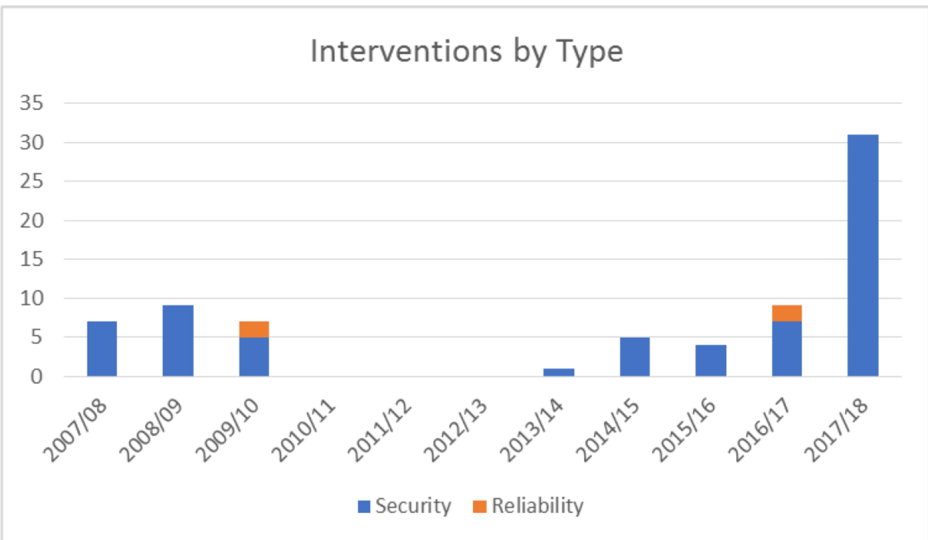
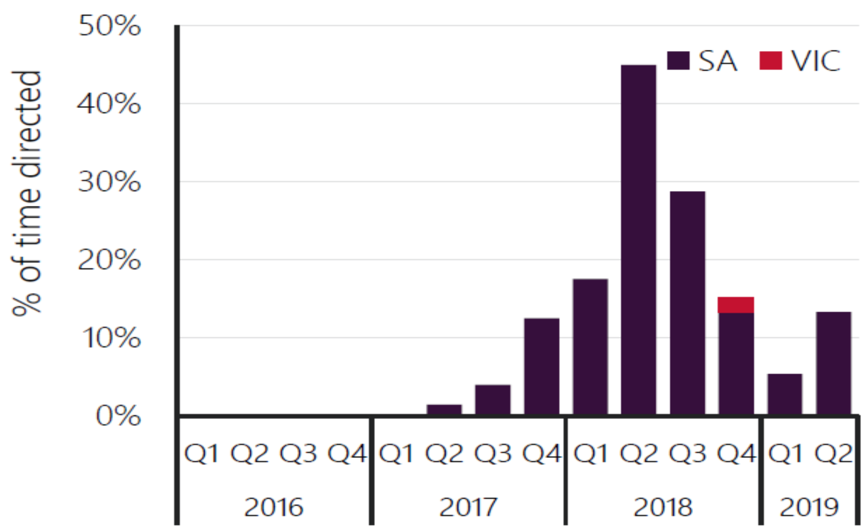


AEMO INTERVENTIONS BY TYPE. SOURCE: DATA PROVIDED BY AEMO

Figure 2 System Strength Directions in South Australia



Ref AEMO Options for NEM design paper September 2019

The number of interventions in the market is increasing and, on occasion, dominates normal dispatch outcomes as illustrated on the previous page. It is unclear how the proposed COGATI access model will be impacted by various types of direction and what will be the resultant risks for participants. Of particular interest are the firmness and value of the FTRs under market directions.

Outcome sought:

1) *Assess the impact of market interventions on network capacities and flows, dispatch outcomes, FTR pay outs and changes in risk and resultant financial positions.*

5. Consistency with future trading arrangements / market design

It remains far from certain that the current energy only market (EOM) will remain suitable in light of:

- State and Federal government interventions via :
  - renewable schemes
  - government sponsored initiatives to augment supply and interconnectors, construction of new generation such as Snowy 2.0
  - other environmental policies and schemes
- Changing supply mix with a high fixed cost and very low variable cost

In a decarbonised supply sector, there may not be a meaningful marginal price (based on, or related to, a physical fuel cost) and it may be set by opportunity costs of participants. In this case it is almost impossible to determine future asset revenues and return on investments, rendering new investments almost impossible.

Given the uncertainty over market design, it isn't clear that the proposed access model would be relevant to alternate trading arrangements, such as a capacity market/payment or a central buyer model. For this reason, the access reforms mustn't be rushed and must be progressed in complete synchronism with market design initiatives.

Outcomes sought:

1) *Assess the relevance and benefits of the proposed access arrangement in the context of a capacity market/payment or a central buyer/central planner trading arrangement*
2) *Seek to synchronise access model reform with any final market redesign arrangement.*

6. Incentives for networks

As a general principle, risks should be allocated to entities best suited to managing them. Networks are in direct control of network performance and availability. Whilst networks don't directly control market price outcomes, they have a major influence as networks impact the supply/demand balance. Therefore, networks need to be exposed to some level of the network availability risk.

There is a reference on Page v paragraph 39 of the consultation paper to an enhanced operating incentive scheme for the TNSPs. Unfortunately, the rest of paper doesn't elaborate on such an incentive. This incentive will be very important to drive the right behaviours and need to be fully developed as part of the access model.

Outcome sought:

1) *Develop the concept of the incentive scheme and provide detailed assessment of the participant risks exposure.*
2) *Compare these risks to the existing arrangements and quantify specific shifts in risk between participants.*

Summary

ENGIE seeks for the AEMC to:

- Ensure that trends towards greater DER penetration is accommodated; local conditions are effectively and efficiently signalled and thus direct response from non-market participants is facilitated
- Ensure that the FTRs are available for the life of an asset and that incumbents are allocated FTRs for the remainder of asset life.

- Provide detailed cost and benefit analysis of the proposed arrangements which also includes cost of changes to participant systems, return on investment and payback period.
- Assess the impact of market interventions on the proposed access model.
- Ensure that the access model is fit for purpose in potential future trading arrangements
- Ensure that networks are properly incentivised to maximise the benefits of the FTRs to participants.

Should you have any queries in relation to this matter, please do not hesitate to contact me on, telephone, (03) 51 35 5040.

Yours sincerely,

David Hoch
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