Ms Merryn York
Chair, Australian Energy Market Commission
Level 15, 60 Castlereagh St
Sydney NSW 2000

19 October 2020

Dear Ms York,

Transmission access reform interim report

ENGIE Australia & New Zealand (ENGIE) appreciates the opportunity to respond to the Australian Energy Market Commission ("the Commission") in response to the Transmission access reform interim report ("the Report").

The ENGIE Group 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.

Design choices

ENGIE appreciates the progress made by the Commission to further develop the detailed design of access reform. ENGIE are particularly pleased to see that the Commission has accepted arguments that longer tenure of FTRs is required. Unfortunately, other detailed design choices give more cause for concern.

Given the Commission's preference to allow non-physical participants to be included in the FTR auction, it is especially important that appropriate grandfathering arrangements are put in place so that existing generators can be confident that they have access to sufficient FTRs.

ENGIE queries the exclusion of non-scheduled participants from exposure to their local marginal price (LMP). It is consistent with the logic underpinning the calculation of the benefits from introduction of the reforms that wider application of the LMP should bring greater benefits. At the very least the option of including non-scheduled participants in the reform could have been subjected to the cost benefit analysis. ENGIE recommends the Commission add this exercise to its future access reform work program.

ENGIE also notes comments made by the Commission in its consultation on rule change ERC0280 Integrating Energy Storage systems into the NEM to the effect that it anticipated that the introduction of a two-sided market would lead to a potential reorientation of rights and obligations in the National Electricity Rules (NER) away from participant registration types and towards services provided and consumed. It does not seem consistent with this approach to introduce different reference prices for different participants based on their registration category. By extension the treatment of load in the proposed model may be problematic, not that ENGIE does not see significant challenges with an environment where load was hedge locally and not regionally.

ENGIE's preference is for the widest range of possible point-to-node FTRs to be available in the auction. It's not clear that this would in itself constrain the development of a liquid secondary market and would maximise participants' opportunity to fully hedge their price risks.

ENGIE fully expects, as is the case in other nodal markets, that specific nodes become reference points for a large proportion of contract trading (for example within a single REZ). With these concepts in mind, there are apparent tensions arising between the use of a regional price for some participants, LMPs for others, suggestions of potential zones, and contract liquidity.

The Commission's proposed "hub"-based model could be one method for managing this process and appears more like a zonal approach to transmission access than a nodal one. Such a zonal approach may lead to dominant nodes within each zone. That said, if a zonal approach, using more granular regions than the current model is what the Commission desires, then such an outcome should be more fully explored or tested. For instance, such an approach could be trialled in existing regions where it is believed significant benefits could be derived (North Queensland, and areas around the New South Wales / Victorian border).

ENGIE has consistently argued that maximising the benefits of access reform entailed placing better incentives on transmission service providers to respond to congestion. To this end, the proposal to adjust the STPIS to be based on the cost of congestion is welcome as it better aligns the interests of TNSPs with those of the market. In the longer term, further consideration should be given to strengthening these incentives – good market and regulatory design should not be unduly governed by the stated risk preferences of particular asset owners.

Finally, we consider that the Commission should only look to implement pricing mitigation measures if there is clear evidence that such measures are warranted.

Costs and benefits

ENGIE considers that it is simply a matter of due diligence that the Commission should attempt to estimate the costs and benefits of a reform of this scale. Conversely, no reliance should be placed on the *specific* net benefit figures that result as they not intended to be precise.

For a reform of this nature, where the goal is improving the efficiency of the market through better aligning it with the physical reality of the system, one would expect that substantial benefits could accrue over time, *providing* there are no impediments to the realisation of those benefits in practice.

On the cost side, there is a one-time systems upgrade for both AEMO and market participants and potentially some modest additional annual expenses – but as processes adjust to the new reality these are unlikely to be material in the longer term.

Accordingly, it's not difficult to see how a plausible cost benefit analysis will result in an expected net benefit an order of magnitude greater than the costs.

However, deriving a specific dollar figure or even a range is less relevant and useful than determining what is required to ensure the benefits are realised, and what impediments could arise to benefits realisation.

An obvious area for investigation is how the reforms will affect the risk profile of participants, especially new entrants (though heightened risk can also drive inefficiently timed exit). The Commission needs to consider how project proponents will be able to hedge their revenue streams over multi-year periods in order to be able to secure finance at efficient cost levels. NERA considers some of these issues in its report[1]. For example, they note that "in reality the volume of FTRs available will be less than the transmission capacity…it may be possible that actual FTR ownership is less than would be required to facilitate optimal hedging." The consequences of these actual or potential departures from the theoretically efficient outcome should be considered more fully.

Other areas for investigation could include, whether risks associated with dynamic losses will be easier to manage than the current annual review of fixed marginal loss factors (MLFs); how contract liquidity will be maintained as the market transitions to the new access regime (especially if vertical integration continues), and whether the regime will make investments more or less robust in the face of difficult to predict forms of government intervention in the market, given this has now become an ongoing feature.

Another reason not to put weight on the dollar figure is the inherent inconsistencies in the overall cost benefit analysis. The costs and benefits are not presented in a consistent way. The underlying logic of NERA's assessment of the gains from locational efficiency, dispatch efficiency and dynamic losses is that the market broadly works, that is it is broadly competitive. But it then imputes potentially very large gains from the erosion of economic rents (i.e. wealth transfers) that can only exist if the market is not currently competitive. Other than the sharper locational signals, however, there's no reason to think that access reform in itself will fundamentally change the level of competition, particularly in retail markets. Accordingly, the supposed wealth transfer calculation appears entirely speculative.

As a more minor point, the costs calculation is purely a gross costs calculation (i.e. "social" costs) rather than an assessment of the cost's customers will face. For consistency and robustness, the costs and benefits should be purely assessed on the social costs and benefits of the reform rather than adjusting for putative transfers between stakeholders.

On the costs front, even if the Commission is confident that the benefits will be a multiple of the costs, it is important that costs are minimised where possible through thoughtful implementation. Market participants are currently incurring large sums on system upgrades for five-minute settlement and global settlement. Other post-2025 reforms may result in similar upgrade requirements. In many cases, these costs represent pure overhead for competitive market participants (network service providers can typically recover these costs through regulated revenues) with no direct recovery mechanism. Logically over time, high costs of participation will lead to fewer participants than otherwise, other things being equal. This could in turn reduce competition in the market.

[1] Cost benefit analysis of access reform: Modelling report, NERA, September 2020

Timing and implementation of the reforms

Having established the basic premise for access reform, its success will depend on careful implementation and sequencing with other reforms. ENGIE agrees that with other potential major reforms to be determined as part of the post 2025 market design project, implementation from 2025 is appropriate. This allows adequate time for the Commission to finalise detailed design choices, to investigate issues such as those raised above to determine where the practical challenges to efficient outcomes may lie, how challenges can be addressed or mitigated, and to undertake regional trials.

Targeting reform from 2025 also allows participants some minor breathing space from the current round of major reforms (five-minute settlement, wholesale demand response, etc.) before gearing up for the next round. Within a few years of this implementation date, the next wave of major coal retirements is expected to commence, which will in turn drive a large amount of replacement investment. Getting the correct locational signals to these new investments will be critical to the efficiency of the NEM through the 2030s and 2040s.

Grandfathering

ENGIE is supportive of extensive grandfathering. Given the importance of maintaining the confidence of investors in the NEM, including those that invested in good faith in the existing access regime, and allowing that freely administered permits to existing plant does not compromise the economic efficiency of the reforms, ENGIE considers that a longer transition is warranted, and would strongly recommend a 10 year timeframe for moving to zero free allocation.

Any attempts to water down grandfathering further from a supposed equity standpoint will impede reform and will not deliver greatest overall efficiency, would fail to take account of the multi-decade horizon against which asset investments are made. ENGIE believes a failure to grandfather is most likely to have an effect of participants requiring increased upfront returns given the contracting uncertainty in the latter stages of their investment.

Should you have any queries in relation to this submission please do not hesitate to contact me on (03) 9617 8415.

Yours sincerely,

Jamie Lowe
Head of Regulation