SUBMISSION

AEMC COGATI PROPOSED ACCESS MODEL – DIRECTIONS PAPER
8 NOVEMBER 2019

EUAA
Energy Users Association of Australia

AEMC
COGATI – Proposed Access Model Discussion Paper
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Via: AEMC submission portal: www.aemc.com.au

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INTRODUCTION

The Energy Users Association of Australia (EUAA) is the peak body representing Australian commercial and industrial energy users. Our membership covers a broad cross section of the Australian economy including significant retail, manufacturing and materials processing industries. Combined our members employ over 1 million Australians, pay billions in energy bills every year and expect to see all parts of the energy supply chain making their contribution to the National Electricity Objective.

Our members are highly exposed to movements in both gas and electricity prices and have been under increasing stress due to escalating energy costs. These costs are either absorbed by the business, impacting their competitiveness and reducing their ability to maintain current levels of employment, or passed through to consumers, increasing the cost of many household items for every Australian.

We welcome the opportunity to make a submission to the Coordination of Generation and Transmission and Investment (COGATI) – Proposed Access Model Discussion Paper (Discussion Paper). The EUAA has already made a number of submissions to the COGATI process including to the Options Paper in October 2018, to COGATI Implementation – Access and Charging Consultation Paper in April 2019 and to the COGATI Access and Charging Directions Paper in August 2019. We were also pleased to participate in the Melbourne workshop on 8th July 2019 and are regular participants as part of the Technical Working Group.

The theme of all submissions we have made and engagement we have been involved in to date, is to challenge the assumption that consumers would continue to pay the full cost for network augmentation and new generator access that is required over the coming years, including these already identified in the AEMO Integrated System Plan (ISP).

We have constantly made the point that the we are not opposed to new network assets being built to facilitate new generation, for interconnectors to be built that allow market participants greater access to the market and to provide the market operator with improved flexibility to manage the energy system. Our concerns have always been and continue to revolve around the assumption that a vast majority of the costs associated with these new assets will be included in the Regulated Asset Base (RAB) of the network companies involved, meaning consumers would not only pay the entire cost but carry all the volume risk.

This situation is both unfair and unreasonable and to continue without change is not in the long-term interests of consumers.

We are pleased to see that the AEMC appears to understand this and is making a genuine attempt to develop a market-based solution to the problem. Having said that, we recognise that what has been proposed is not a "silver bullet" and it will not solve all issues associated with the transition of our energy system and funding of initiatives such as the AEMO Integrated System Plan (ISP). It seems clear that further actions outside the scope of COGATI or jurisdiction of the AEMC is likely to be required.

The scale of the problem we are trying to solve can't be underestimated, nor can the potential for unintended consequences. Given the complexity of the reform and the significant disruption to the status quo it is likely to create, we accept there will be a range of views. Indeed, many EUAA member companies have raised concerns about the impacts and timing of this reform and in the absence of detailed scenario modelling, are concerned that many energy users may well be worse off should this reform proceed.

We understand this reform is causing market participants some concern, but we must recognise that rejecting past reform because they were "too big" or "too complex" or because the "timing is wrong" is partially to blame for the situation we are currently facing. Many of the reforms we are contemplating today, including those outside the bounds of this Discussion Paper, have been spoken about for many years and were delayed or rejected for similar reasons. If it is agreed that the status quo is unacceptable and that reform is required then we must at some point begin to make considered decisions, backed with robust analysis and in-depth consultation.

We urge the AEMC to continue to work with all stakeholders and undertake this detailed scenario modelling as a matter of priority to give all market participants confidence that the reforms described in this Discussion Paper deliver the promised outcomes.

Much of the substance of this Discussion Paper and many of the questions being asked are not directly related to large energy users, although the outcomes by way of cost and risk allocation stemming from the development of efficient, market-based frameworks are of great interest to the EUAA and its members. Therefore, we will not be responding to all 33 questions in the Discussion Paper with our primary response focusing on supporting the overall reform package while making comments on specific areas of interest and importance as they directly impact large energy users.

THE NEED FOR CHANGE

We agree with the following statements taken from page 6 and page 7 of the Discussion Paper and feel it is a good summation of the transformation challenge facing all market participants, regulators and the market operator.

Generation roughly equal to the current size of the NEM (50 GW) is foreshadowed for connection to the grid over the next 10 years. The national electricity market will replace most of its current generation stock by 2040. Unlike the existing power system, the system of the future is likely to be characterised by a large number of relatively small and geographically dispersed generators.

Further, these generators are unlikely to be located where there is substantial existing transmission to serve them instead being connected in sunny or windy areas at the edges of the grid, where the network is less strong. In addition, these new types of generation can in general be built more quickly than transmission infrastructure required to serve it. Substantial and timely transmission infrastructure is therefore likely to be required.

This trend is only going to continue. AEMO's ISP in the 'neutral with storage' modelling scenario shows that by 2030 over 6,000 MW of existing generation is expected to close and be replaced by approximately 22,000 MW of renewable generation and 6,000MW of storage. By 2040, the amount of expected closure increases to approximately 16,000 MW, which is projected to be replaced by 50,000 MW of renewable generation and 20,000 MW of storage. [1]

The scale of this challenge can't be underestimated and can't be wished away as if it isn't going to happen. These changes are inevitable and are being driven by government policy, disruptive technologies and significant changes in consumer behaviour

[1] https://www.aemc.gov.au/sites/default/files/2019-10/EPR0073%20-%20COGATI%20Proposed%20Access%20Model%20-%20Discussion%20paper.pdf

and preferences. This change will create new opportunities for investors, technology providers and consumers, all of whom should pay their fair share of the transition costs, given they are also likely to be significant beneficiaries.

Change Of Ownership

In addition to the changes described in the Discussion Paper, we would also point out that the ownership of energy assets has undergone a fundamental change over the last 20 years that will also impact the future of our energy system. It must be recognised that a majority of our energy system was built by State Governments, where the cost and benefits were largely socialised. Within this closed system of costs and benefits and where governments largely took on the risks associated with long-life assets such as transmission and generation, it was appropriate that all consumers paid a regulated price.

We are now faced with a market that is largely privatised and with a significant increase in new, non-government participants (i.e. new entrant generators) the closed system of costs and benefits no longer exists. With this, the fundamental driver for investment has changed. Non-government participants in the energy system invest to make a profit for shareholders where past government participants in the energy system invested to provide a public service.

Given this change of ownership has altered the fundamental driver for investment, it is no longer appropriate that all the costs are "socialised" amongst consumers.

This is one of the primary drivers of our advocacy to see a more equitable sharing of costs associated with the energy transition. To the extent that consumers benefit directly from investment in energy infrastructure, they should pay their fair share. Likewise, to the extent that energy industry participants (i.e. new entrant generators) benefit directly from investment in energy infrastructure, the should also pay their fair share.

Risk And The Rapidly Changing Market

There are many risks associated with the rapidly changing energy market including dramatic changes in consumer behaviour, the emergence of disruptive technologies and the rapid transition to a system increasingly reliant on highly disbursed, variable sources of generation. What we are witnessing is that these risks have significant impacts on the feasibility of new energy related infrastructure such as large-scale generation and transmission (including interconnectors).

This is being played out right now as number of proposed transmission assets such as the Energy Connect project, Project Marinus and the transmission upgrade to facilitate Snowy 2.0 face the potential of an uncertain future. While highly unlikely to be stranded assets and over time may be fully utilised, it must be recognised that the risk of extended periods of underutilisation is material. In the past, this type of risk would have been contemplated and accepted by government owners who would have still pursued the asset if it was deemed in the public good to do so.

For example. In the case of Energy Connect there are two fundamental assumptions underpinning the consumer benefits of this project being:

- That the NSW region will continue to be in a state of "oversupply", especially with the type of asset required to provide "firming" of variable generation and,
- Fuel savings that come about when 800 MW of gas fired generation retires in SA (2024) and a further 63 MW of generation fired by liquid fuels retires in 2027.

Yet according to the AEMO ISP, two NSW based coal fired assets in Liddell (in 2022) and Vales Point (2028) are assumed to retire, removing some 3,320 MW of the type of dispatchable generation that is required in both NSW and SA. The assumption that you can continue to "borrow" dispatchable power from your neighbour will be progressively undermined by this paradigm shift in the energy market. We also note that the cost of thermal coal continues to increase.

When taken together, the likelihood of New South Wales providing cheap power to South Australia has been greatly diminished and can't necessarily be relied upon into the future.

Perhaps more importantly is that the South Australian fuel replacement assumption is already under serious threat. While replacing expensive gas with cheaper resources imported from another state is a key value driver for the Energy Connect project, we note that AGL have completed construction of the 210MW gas fired Barker Inlet Power Station[2] and the Federal Government have announced that Alinta's 300MW gas fired Reeves Point Power Station is on the short list for their Underwriting New Generation Investment initiative[3].

While these new projects will be more efficient they will still rely on an expensive fuel source. Therefore, we have serious concerns that some of the key assumptions underpinning the consumer benefits of the project can't be relied upon. In a market that is changing so rapidly, to the extent that the Energy Connect business case identifies consumer benefits, they may be fleeting at best. This is just one example of where a rapidly changing energy market could significantly impact the consumer benefit of this type of investment. Under the exiting approach, energy consumers would carry the entire risk.

Compelling Case For Change

It is for these reasons that we are fully supportive of the AEMC approach laid out in the Discussion Paper and, while not a silver bullet, it will go some way to ensuring the costs and risk of new energy infrastructure is met by those who will benefit the most from it and are in the best position to manage the costs and risks. We are encouraged that with these fundamental changes, the AEMC and others are recognising the need for reform in the way we plan and pay for large, long life assets.

THE PROPOSED MODEL

As stated previously, the proposal for a revised access and charging regime described in previous consultations is not a silver bullet and is unlikely to have resolved cost sharing issues associated with large infrastructure projects described in the AEMO ISP or Renewable Energy Zones (REZ). In this regard, we will be responding to the REZ Discussion Paper that sits alongside this Proposed Access Model Discussion Paper.

The proposed model described in the Discussion Paper represents a significant change to the status quo and will no doubt raise concerns amongst market participants. To avoid creating further uncertainty, our understanding of the intent of the proposed model is that:

- Load (customers) will continue to pay the Regional Reference Price (RRP) meaning they will not be exposed to the Local Marginal Price (LMP) should it differ from the RRP.
- Load will be able to "opt-in" to receiving the LMP should it be in their best interests to do so, recognising that in order to do so the customer would need to become a market participant, exposing them to greater complexity and risk.
- Load will be able to subsequently opt-out after a period of 12 months.
- LMP will only differ from RRP on occasions where there is local congestion. At present, this is likely to have an impact on predominantly new entrant generators and could potentially add to their costs to the extent to which will be dependent on the efficiency of the proposed FTR arrangements. However, these new entrant generators are facing significant financial impacts of curtailment and reductions in MLF now, which this reform is designed to address.

[2] https://thehub.agl.com.au/articles/2019/11/fast-and-flexible-energy-from-barker-inlet-power-station
[3] https://www.energy.gov.au/government-priorities/energy-supply/underwriting-new-generation-investments-program

- Because separation of the LMP and RRP will only occur at times of congestion, it should not materially impact a majority of existing thermal generation (although we are aware of exceptions) as constraints are less likely. However, it may have an impact in the future as more generation enters the market. The additional costs being borne by these generators in the future needs to be understood.
- In addition to other reforms to assist generators deal with information asymmetry issues associated with MLF, Dynamic Regional Pricing should assist generators address congestion (and MLF) issues and would work to reduce overall financial risk, leading to lower cost of capital and lower energy prices for consumers.
- Generators (and other relevant market participants) that are impacted by a constraint, will be able to purchase Financial Transmission Rights (FTR's) via periodic auctions administered by AEMO. This is intended to be a market-based approach where existing tools and market structures are utilised as much as possible as a means of mitigating some of the disruption caused by the reform.
- The revenue raised from the auction of FTR's will be used to "pay out" holders of these rights where there is a constraint and the LMP and RRP have separated. In essence, FTR's act as a financial insurance product, the level of which is chosen by the impacted participant.
- The commission proposes to move from a Regional Reference Price (RRP) to a Volume Weighted Average Price (VWAP) that incorporates the average price across all LMP's in a region, therefore delivering a regional price that is a more accurate reflection of delivering power to consumers in each region.

The proposed model (including REZ arrangements) are intended to resolve many of the risk, cost and funding arrangements for new infrastructure. However, given the scale, complexity and risk of the energy transition, we believe there may be a significant role for governments to play in shielding energy users from unnecessary costs and risks while converting initiatives such as the ISP, into an actionable plan.

Federal Government announcements over the last 12 months that articulate funding support for Snowy 2.0 and Marinus Link and more recently the announcement of the $1B Grid Reliability Fund[4] can be seen as a recognition that some of the costs and risks associated with the transition of our energy system may be too great for non-government participants or energy consumers to bear on their own.

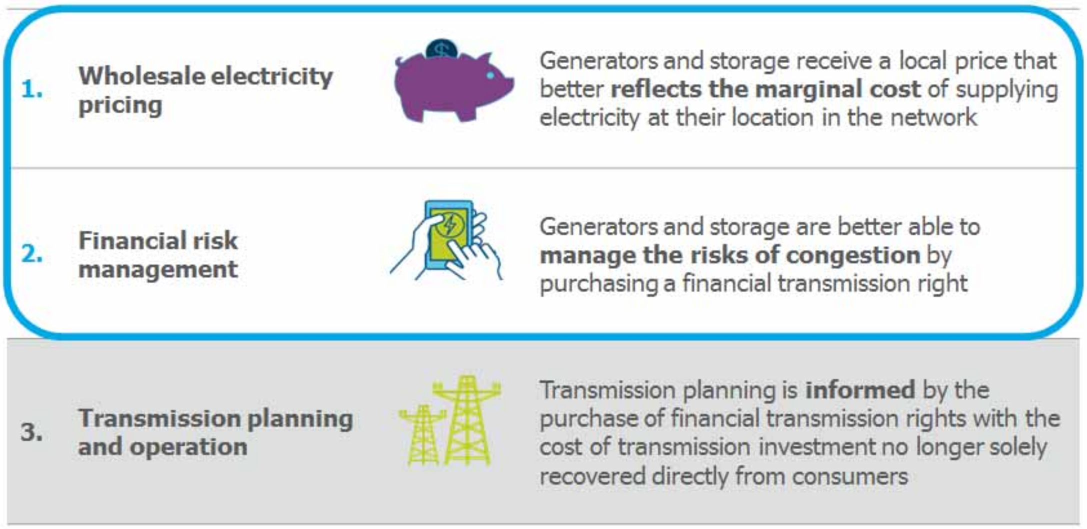
While significant government intervention in the energy market is to be discouraged, especially where it is in conflict with non-government investors, we welcome this support as part of a broader government strategy of strategic intervention when it is clear non-government participants are unwilling or unable to be involved. It appears the AEMC too have recognised the initial ambition of the previous version of the access and charging reforms may be too great a challenge and would not have resolved a number of the long-term funding and cost sharing issues we are currently facing.

Having consulted with both large energy users and a number of supply side participants, we must concur with this sentiment. While there are a number of unanswered questions regarding the reforms proposed in this Discussion Paper, we believe the revised scope of the reform, set out in the figure below, taken from page 12 of the Discussion Paper[5] is still worthwhile pursuing provided:

- It can be clearly demonstrated to be in the best interests of consumers,
- It is a complimentary part of an overall energy market transformation plan (i.e. ESB post 2025 Market Design),
- The degree and magnitude of unintended consequences is understood and managed and
- Appropriate transitional measures are put in place.

[4] https://www.energy.gov.au/government-priorities/energy-programs/grid-reliability-fund
[5] https://www.aemc.gov.au/sites/default/files/2019-10/EPR0073%20-%20COGATI%20Proposed%20Access%20Model%20-%20Discussion%20paper.pdf

Figure 2: Overview of the previous model



Source: AEMC

We are pleased to see the AEMC acknowledging that other reforms are running parallel to this such as the ESB Post 2025 Market Design and AEMO ISP, and we welcome the efforts being made to synchronise and synthesise these multiple reforms to the greatest extent possible.

DYNAMIC REGIONAL PRICING

With the additional information provided in the Discussion Paper we have a growing understanding of the “mechanics” of Dynamic Regional Pricing. Notwithstanding the additional complexity, we can see there could be benefits associated with a more granular wholesale pricing regime that provided a range of locational price signals for generation and load. However, while this Discussion Paper does provide a more detailed description of the reform and identifies a number of benefits, it is unfortunate that it still largely lacks a substantive body of evidence to support many of the assertions being made.

Clearly, significant quantitative analysis needs to be conducted to validate the AEMC’s stated benefits. We will make further comments in this subject later in this submission.

As a vast majority of energy users are not market participants and therefore will not have a day-to-day operational involvement in dynamic regional pricing or transmission hedges, our comments will focus on energy user outcomes and the extent to which these reforms work to reduce consumers costs, mitigate risk and increase competition.

While not privy to the actual details, we are aware that some large energy users have complex agreements in place to purchase electricity from market participants. Power Purchase Agreements (PPAs) are an example whereby the large energy user may receive the regional reference price from a renewable generator and in exchange pay the generator a fixed price for the generated electricity.

As large energy users are generally not market participants themselves, an energy user may manage the financial risk of a PPA by having an offsetting arrangement whereby they pay the regional reference price to the retailer. It is not clear to the EUAA, how PPA arrangements of this nature would be affected by dynamic pricing.

The Discussion Paper makes several references to non-scheduled participants continuing to face the regional reference price, such as this statement from Section 4.2.2 on page 30 of the discussion paper:

"Non-scheduled participants (regardless of whether they are load or generation) will continue to face a regional price for wholesale electricity. The majority of non-scheduled participants are currently on the demand side of the market, as load. For example, this comprises all retail load."

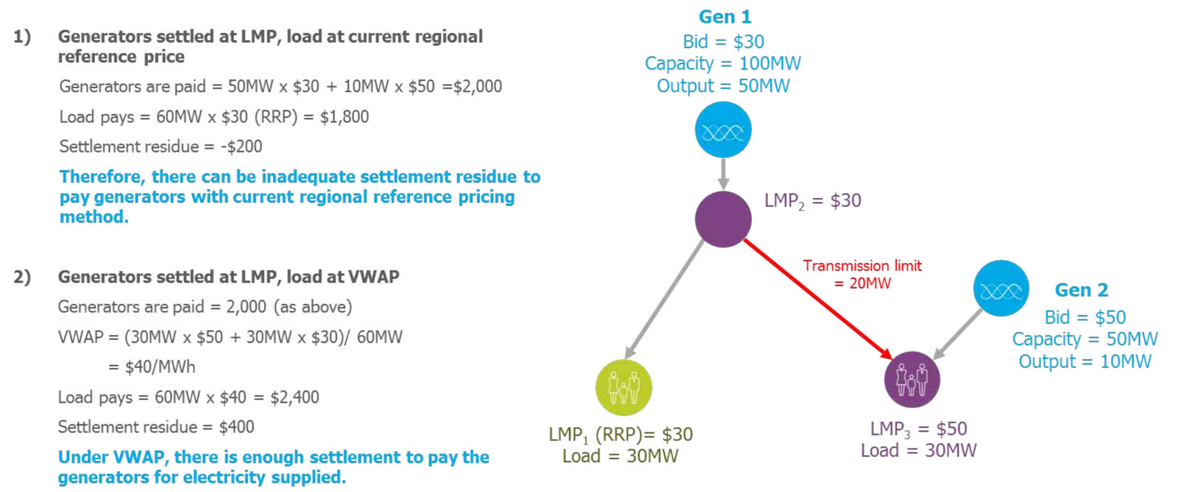
Despite this, based on feedback from member companies the EUAA is concerned that large energy users with PPAs may be still end up facing the local price instead of the reference price and may find themselves paying for the generator's costs associated with purchasing Financial Transmission Rights. We seek further clarity on this situation and recommend that the AEMC seek out energy users who are holding these contracts to ensure these issues do not place these parties at a material disadvantage.

Further concerns have been expressed that as the AEMC has only considered that market participants would be eligible to purchase transmission rights that it may lead to large energy consumers with PPAs incurring a financial loss. This comes about if dynamic pricing were to be introduced and an impacted party (i.e. large energy user with a PPA) were unable to purchase transmission rights to maintain their contractual position.

The complexity of electricity contracting market and the financial relationships between market participants and energy users requires that the AEMC undertake specific scenario modelling to stress test the potential financial outcomes that could occur if dynamic pricing is introduced to ensure that there are no unintended consequences that adversely impact costs paid by energy consumers.

The EUAA is also unclear what the impact to consumer energy costs may occur from moving from a Regional Reference Price (RRP) to a new reference price calculated as a Volume Weighted Average Price (VWAP). The example below given on page 37 of the Discussion Paper and appears to show that load (customers) will pay more under VWAP. [6]

Figure 4.1: Wholesale settlement under the current regional pricing method and VWAP



Source: AEMC

[6] https://www.aemc.gov.au/sites/default/files/2019-10/EPR0073%20-%20COGATI%20Proposed%20Access%20Model%20-%20Discussion%20paper.pdf

Without employing sophisticated modelling that demonstrates the whole of market impacts of the reforms we do not understand what pricing outcomes may occur under this revised methodology given generators may be motivated to bid differently to optimise their financial outcome if dynamic pricing was introduced. While we understand the theoretical explanation in the Discussion Paper, the absence of hard data from quantitative analysis makes it difficult for the EUAA to make comment on the impact on costs passed through to energy consumers.

Given this, in the absence of this supporting rigorous quantitative analysis, it is not clear that the AEMC has demonstrated the benefits for introducing complex dynamic pricing at this time. We look forward to working with the AEMC on this analysis and to the outcomes that clearly demonstrate consumer benefits of the proposed reforms.

FINANCIAL TRANSMISSION RIGHTS

We hope that over time the existence of Financial Transmission Rights (FTR's) will create sufficient incentive for market participants behind a constraint to make appropriate investments in technologies that enhance their ability to physically manage their exposure to future congestion risks. We also hope that it will lead to market participants behind the constraint to work more collaboratively to resolve the constraint for all impacted parties by way of engaging in Scale Efficient Network Extension (SENE) type investment.

In general, the EUAA does not have a view to offer on the specifics of how FTR's should be dealt with other then to encourage the development of a market that is both highly liquid, highly transparent, does not result in perverse incentives and is open to both market participants and energy consumers.

However, we have received feedback from member companies raising a number of issues that require further explanation.

While in theory FTR's may be a sound market-based response, in the absence of robust quantitative modelling, it is not clear to the EUAA that the creation of FTR's (alongside Dynamic Regional Pricing) as a market-based means of resolving congestion and managing MLF risk will create sufficient revenue stream to help off-set some minor network augmentation costs (in doing so reduce consumer costs and exposure to risk).

For example, some stakeholders are concerned that it may be possible that introducing transmission rights results in a net loss occurring between the total revenue paid to transmission rights holders and the total cost paid by the generators. Transmission rights will result in a holder receiving revenue in times of constraint but does not impose an obligation on the holder to pay costs for the difference between the local price and the reference price. It is therefore possible that the costs paid to acquire transmission rights may not cover the total revenue received by the transmission right holders.

Other concerns have been raised that generators in non-congested transmission areas are unlikely to be motivated to purchase transmission rights if they believe there is little benefit to obtaining them. This may mean that the introduction of transmission rights leads to a net loss that would need to be recovered from energy consumers.

Perverse outcomes may also occur if transmission right holders are paid based only on the volume of rights purchased and that it is not linked to a generators physical dispatch. We are concerned that not linking revenues paid to transmission right holders to physical dispatch will open the door for market participants to game purchasing transmission rights at locations where the revenues received are expected to be high leading to higher costs being passed through to energy consumers.

Settlement Residues

As we have stated in previous submissions, our preference is for settlement residues to be returned to customers by way of lower TUOS charges. The following table appears on page 64 of the Discussion Paper[7], providing a brief overview of the AEMC proposal on the treatment of excess settlement residue.

In the absence of returning all excess settlement residues directly to customers (which in hindsight would be detrimental to building a highly liquid market), the AEMC preference of creating a single fund, administered by AEMO, where excess settlement residues accumulate, does have merit provided that the process is transparent to all stakeholders and there are appropriate (and timely) reporting requirements.

We are supportive of the option of capping the total dollar amount of the fund and returning any excess to consumers on an annual basis. The process of setting the annual cap must be transparent and open to a level of public consultation as should the annual distribution of excess funds. Building energy user confidence that their money is being used wisely should be a priority of both the AEMC and AEMO.

We would also see a role for the AER to provide some independent oversight to ensure market participants (especially those with assets in multiple locations) are not attempting to game the system. In its purest form, the approach proposed by the AEMC could be an efficient means of reducing overall risk for participants and therefore, producing lower cost outcomes for consumers, however we would need to see the results of scenario modelling by the AEMC to verify this.

QUANTITATIVE ANALYSIS

Given the complexity of the proposed reforms and the uncertainty that they will lead to better outcomes for consumers, we are pleased to see that the AEMC intends to conduct quantitative modelling of this COGATI reform. Providing stakeholders with greater depth and breadth of information on what the likely outcomes will be against a base case of status quo will be important to build a level of trust that the reform will actually do what it is intended to do.

We would not be in favour of pursuing these reforms without first undertaking robust quantitative analysis that clearly demonstrates the reforms will not only work in achieving the stated objectives but are also in the best interest of consumers The confidence that this will be the case can only be underpinned by a thorough cost benefit analysis. We also need to have greater confidence that unintended consequences and perverse outcomes are mitigated or avoided through improved design of the proposed reform.

On page 82 of the Discussion Paper, the AEMC provides an overview of the proposed categories it intends to study being:

1. Cost of reform
2. Benefits of reform
3. Policy design
4. Distributional impacts
5. Communication

Of these, benefits of reform and policy design should be given the greatest priority.

[7] https://www.aemc.gov.au/sites/default/files/2019-10/EPR0073%20-%20COGATI%20Proposed%20Access%20Model%20-%20Discussion%20paper.pdf

CATEGORY	NATURE OF TASK	BY DECEMBER 2019	BY MID-2020
2. Benefits of reform	Benefits of reforms	Research into the benefits of introducing comparable models elsewhere	
	Better risk management for generators	Initial estimate of benefits of improved risk management	Survey of generators
	Improved operating incentives for generators	Literature review of race to the floor behaviour	Forward modelling the cost of race to the floor bidding
	Improved dispatch efficiency	Initial estimate of benefits from dynamic loss factors	
	Better locational incentives to invest	Initial estimate of historic costs of congestion	
3. Policy design	Market power	Zonal study of network to ascertain how many participants are in each location to get an indicative estimate of market power potential	
	Sufficient settlement residue to back financial transmission rights		Simultaneous feasibility study of the network to estimate what possible payouts

Benefits Of Reform (Priority 1)

For energy users, having confidence that the reforms deliver benefits by way of lower relative prices and a more equitable sharing of risk are of paramount importance. Energy users understand that significant additional capital expenditure will be required over the coming years and there will be cost impacts. Establishing a reliable "base case" that represents what continuing with the status quo will deliver by way of costs and risk for consumers will be important.

We agree with the list of objectives under "nature of task". However, understanding the "risk premium" consumers take on when underwriting long-lived assets like transmission will be important. We are particularly interested in the risk premium associated when consumers pay full value for the asset (by way of TUOS) regardless of asset utilisation or direct benefit.

For example, if a new interconnector had an average utilisation factor of 70%, then the value assumed to be received by consumers should be discounted or reduced. Similarly, if a new asset has multiple beneficiaries, such as new entrant generators, then the assumed value consumers receive should also be discounted.

This is central to our approach where all stakeholders who benefit from an investment should pay their fair share and carry their own risk. We suggest a scenario that considers this should be part of the benefits of reform task.

Policy Design (Priority 2)

The second of our two priority areas. We agree with the list of objectives under "nature of task". We would also add that a scenario be developed that considers the impact of other reforms and the changes in stakeholder behaviour that these will bring about. The AEMC have recognised the need to consider reforms such as the AEMO ISP and ESB Post 2025 Market Design and we think it would be worthwhile developing scenarios around likely key outcomes from these.

For example, the emergence of some form of capacity market or capacity/reliability incentive (i.e. Retailer Reliability Obligation) or the day ahead demand response market is likely to have a significant impact on investment decisions be market participants. How these reforms are likely to impact (positively and negatively) on the reforms described in this Discussion Paper will be important to understand.

Costs Of Reform

While costs of reform will be important to understand, it is all too often used a reason not to pursue the reform in question. Given this will be done as a survey of market participants we would be wary of "inflated costs" being provided by some stakeholders. In addition to the AER providing its views, we would encourage the AEMC to engage an independent body to provide a review of these costs.

Distributional Impacts

While not directly impacting energy users, distributional impacts will be important to understand by those impacted stakeholders. Any reform on the magnitude being contemplated in this Discussion Paper will create "winners and losers". This is unavoidable.

More importantly than identifying those parties will be to ensure measures are in place that ensures the winners can extract monopoly rents from the process or don't end up with wind-fall gains. Equally, we need to ensure the losers have a viable means by which to recover their position over time and are not unduly restricted or disadvantaged such that competition is reduced.

Communication

As with any major reform, the fear of the unknown and resistance to change represent major obstacles. Providing timely, accurate and transparent information and encouraging engagement and learning by doing are effective tools in managing this. Therefore, we fully support the concept of running a paper trial using 10 nodes over a limited timeframe.

We also understand that AEMO are considering developing a "digital twin" of the NEM, which is an excellent initiative. We suggest the AEMC engage with AEMO on the development of this tool and use it to further stress test the concepts discussed in this Discussion Paper.

TRANSITION

As with all significant reforms, the ability for market participants to transition at least cost to new arrangements is critical to ensure unintended consequences and perverse outcomes are either mitigated or avoided.

For large energy users we would make the following points:

- If large energy users holding PPA's end up facing the local price instead of the regional reference price, we would recommend these contracts be subject to grandfathering arrangements that ensures the customer does not face adverse pricing impacts by way of excluding the contract from facing the local price regardless of system constraints. The contract would still be subject to variations in volume due to MLF but would exclude the price volatility that may ensure.
- If large energy users holding PPA's end up facing the local price instead of the regional reference price and grandfathering of the contracts is not an available option, we would recommend that grandfathered FTR's be given in the first instance, to the customer as a means of directly managing their exposure and maintaining their financial position.