MONASH University

# COGATI – ACCESS AND CHARGING

## CONSULTATION PAPER RESPONSE

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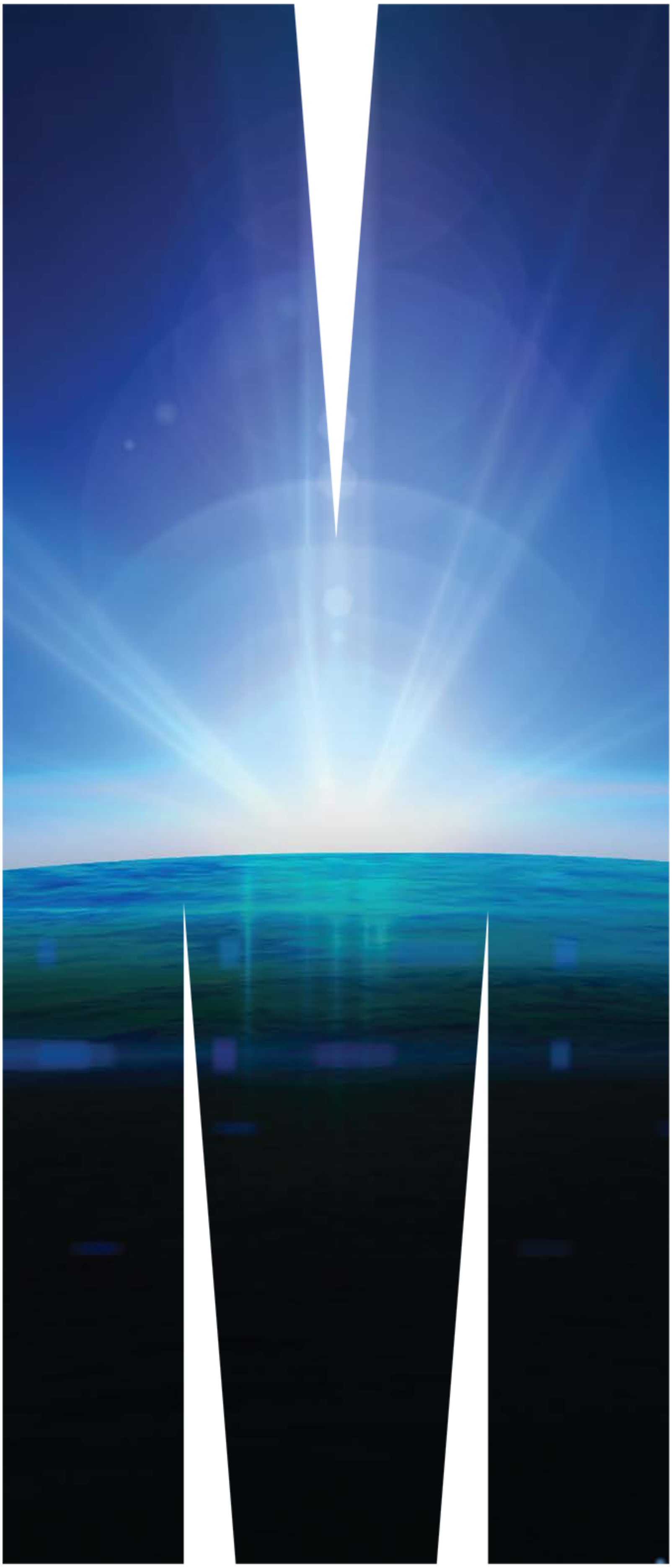

# CONTENTS

**KEY POINTS OF THE SUBMISSION**

Dynamic regional pricing ..... 3

Transmission investment funding: Using firm transmission rights to solve coordination problems in investment and generation ..... 4

**DETAILED RESPONSE**

Dynamic regional pricing ..... 5

Transmission investment funding: Using firm transmission rights to solve coordination problems in investment and generation ..... 10

**REFERENCES**

# KEY POINTS OF THE SUBMISSION

## Dynamic regional pricing

- Dynamic regional pricing (traditionally known as locational marginal pricing or nodal pricing) is not a new or revolutionary concept. Locational marginal pricing (LMP) is founded on sound economics and has our conditional support.
    - This is a bid-based, security-constrained, economic dispatch market model. Unlike the existing market model, this design more accurately aligns the market model with physical constraints and loss characteristics of the network in real time.
    - LMP prices rewards and charges market participants based on the as-bid economic impact of their generation and consumption actions. This better aligns private incentives with that of a system operator that seeks to minimise the as-bid costs of generation given the configuration of the network. This should improve short-run efficiency and provide better investment signals to improve long-run efficiency.
    - Prior theoretical research has demonstrated system-wide efficiency gains from this market model. Empirical research has found efficiency gains in California following their transition from a zonal market design to an LMP market design.
- There are subsequent policy decisions that must be made when implementing locational marginal pricing. Two major decisions relate to
    - the treatment of load pricing; and,
    - the merchandising surplus the market operator will collect when the network is congested.
- We have concerns with the model put forward in the Consultation Paper on both issues.
    - We agree that there are benefits to having all load nodes in a region facing the same wholesale price, but strongly caution this price being set to a regional reference node's shadow price. Instead, we support the traditional LMP model where load faces a load-aggregation point (LAP) price, a load-weighted average of the nodal prices within a region. This reduces the potential for harmful market gaming and should provide a fairer distribution of the costs among all consumers in a region.
    - Refunding the merchandising surplus (intra-regional settlement residues) to generator owners appears arbitrary and without a strong economic reasoning. It risks giving dominant generators incentives to induce congestion to increase the merchandising surplus if their payout share outweighs the loss of local revenue. We support a model that initially refunds to load on a load-weighted basis since they are the customers that pay the embedded costs of the system and therefore seem most entitled to the merchandising surplus. Further, we recommend investigating the historical performance of the auctions for inter-regional settlement residues to help better evaluate other policy options available to the NEM.
- Changes to marginal loss factors should be included in a transition to an LMP market design. Locational marginal prices usually contain energy, congestion and loss components. Given loss attribution depends on the locations in the network of generation and load, loss factors should be made dynamic to further align participant incentives with the dynamic costs of losses. The application of dynamic losses in local energy pricing has particular utility for battery storage where the energy arbitrage after battery losses at fixed loss factors is not sufficient for efficient deployment of storage. Dynamic loss factors would encourage more storage when dynamic loss factors are low and more generation when dynamic loss factors are high, which would be more efficient than applying static loss factors for storage and generation based on the product of the forecast dispatch weighted MLF and the regional reference price under regional pricing.
- There are numerous markets around the world that use LMP. We can study the design of these markets and the transition plan they used when planning the NEM's transition.

  - There is no need to reinvent the wheel. This should be a relatively straightforward application of the methods developed in other LMP markets and we have the benefit that we can learn from their lessons and utilise any expertise available.

### Transmission investment funding: Using firm transmission rights to solve coordination problems in investment and generation

There are some attractive features from moving toward a transmission model that allows for generator owners to face the costs of transmission investments, but it is not without challenges. We question whether the proposed model will result in substantive change.

- In principle, a model that has generator owners face the cost of transmission investments in exchange for FTRs should encourage prudent siting of generators and transmission investments and is consistent with minimizing the long run costs of supplying electricity.
- However, there are some major issues that need to be considered in developing a new transmission model that leads to substantive change:
  - Coexistence with the existing regulated asset model under the Regulatory Investment Test for Transmission (RIT-T), where investment costs and a regulated return are recovered from ratepayers.
    - If a transmission project is developed under the model with the generator(s) funding the project receiving FTRs, then it most likely would have satisfied the conditions of the RIT-T. But all else equal, generator owner(s) prefer the RIT-T mechanism because approved projects are recovered from transmission customers, so the generators won't have to self-fund the investment and it can compete purely on the value of energy as do all incumbent generators
  - Competition (or lack of) for transmission development
    - If regional transmission network service providers are the only entities that generators can engage with, these entities might be able to capture all rents generated from the project.
  - Non-excludability and potential for free-riding
    - The lumpiness of transmission investment means that the FTR model only removes some of the strategic incentive for some generators to free-ride on the investment in transmission infrastructure funded by others.
  - Economies of scale in transmission investment and first mover disadvantage
    - Scale economies mean that the first increments of installed transmission capacity are more expensive and have longer lead times than subsequent expansions. This may create a first-mover disadvantage and result in strategic delay of investments as generators wait for others to make the initial investment.
  - Absence of future generators/market participants
    - The significant gap in planning horizons for new transmission lines on new easements (5-8 years) relative to new renewable generators (1-3 years) may mean that some participants that may benefit from a new transmission investment may not participate in the initial process that determines the scale of the investment. As a result their demand for the investment may not be captured in any proposed planning mechanism/process and the resulting scale of the investment may be inefficiently small. This issue might remain under all transmission planning models, but is potentially more of an issue under an FTR-based model, because a regulatory approval model could be designed to forecast future generator entrants.
- Overall, we find it difficult to foresee how the FTR model will overcome market failures in transmission investment, given its coexistence with the RIT-T and the strategic incentives facing potential generator entrants. Further consideration should be given to whether this potential rule change is constructive and whether policy resources should instead be provided to improve the design or interpretation of the RIT-T process or to consider alternative means of funding transmission projects.

# DETAILED RESPONSE

### Dynamic regional pricing

This section expands on the opening summary and is the response to Questions 2 and 3 in the Consultation Paper.

### Background

Dynamic regional pricing (traditionally known as locational marginal pricing, or nodal pricing) is not a new or revolutionary concept. Bohn, Caramanis and Schweppe (1984) introduced a framework for deriving optimal spot prices in electricity networks varying across space and time. The Federal Energy Regulatory Commission (United States) has included locational marginal pricing as a general principle in its Standard Market Design for electricity markets (FERC, 2002 p.6).

The primary appeal of locational marginal pricing (LMP) is in the incentive structure that it provides. In the short-run, self-interested market participants are incentivised to compete to be dispatched in a security-constrained market model that results in an efficient use of the network given the participant bids and offers. In the long-run, the LMP framework encourages the siting of new generation and demand response at existing locations in the network where they will lower system-wide costs the greatest. A study of the 2006 Californian transition from zonal to nodal pricing found economic benefits resulting from the market design change, driven by a reduction in plant starts and fuel use of the generation fleet (Wolak, 2011).

An LMP market design sets prices that signal the as-bid economic value of energy at a node in the network because the market is modelled in a manner that integrates the physical network characteristics.[1] It is possible that arbitrary market design rules that are incoherent with the physical network can result in prices departing from the economic impact of the action and subsequently result in sub-optimal outcomes. For this reason, it is a common misperception that zonal markets (such as the current NEM design) are "simpler," where in fact they often entail many patchwork solutions to overcome the disconnect between dispatch rules and market rules.[2] For example, the notion of "constrained-on" and "constrained-off" are an artefact of a zonal market design. An LMP market model gives broadly the same outcome as the existing zonal market model in the absence of constraints, the difference arising from the impact of the more accurate loss representation from dynamic loss factors.[3] However, in the presence of intra-regional constraints, zonal markets are required to constrain generators on or off to prevent violation of system constraints, whereas an LMP market model inherently provides security-constrained economic dispatch that ensures all generation that offers under their locational marginal price is dispatched according to, and paid, that price.

Because an LMP market model gives approximately the same outcome as the existing zonal market model in the absence of constraints, there can be a resistance to change the market model.

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[1] That is, the price at a given node is equal to the gradient from withdrawing energy at that node with respect to the market operator's objective function to minimize the as-offered costs to meet demands at all locations in the network. Therefore, participants pay or are paid the marginal impact of their action on the as-bid whole-of-network cost function.

[2] Refer to Hogan (1999) for a discussion of the misperception that zonal markets are "simpler" than nodal markets.

[3] The zonal model applies dynamic loss factors to the interconnectors with volatile loss factors, because marginal losses can vary from 5% to 30% over the power transfer range. This improves inter-regional dispatch efficiency relative to fixed loss factors.

However, our opinion is that a move to an LMP market design should be viewed as inevitable due to the penetration of intermittent renewable energy that will more often result in binding intra-regional transmission constraints. It is also more useful in the presence of distributed storage, particularly at the edge of the grid where marginal loss factors are more dynamic with variable renewable energy connected. This is already dramatically apparent in North Queensland where intra-regional loss factors have moved from 1.1 to 0.87 and the inherent loss factors are much more variable over the day.

Failure to integrate the physical network constraints into the market model can lead to undesirable incentives which are usually efficiency degrading.[4] To give an example from the NEM, generator owners face the marginal price of energy at a regional reference node instead of the location of their generator, and in some situations their optimal strategy can be to bid in what has been termed as a "disorderly" manner (AER, 2013), changing the merit order of dispatch and consequently impacting economic efficiency. Harvey and Hogan (2000) provide an analysis of arguments regarding the competition differences under the market designs, where they demonstrate how zonal markets effectively subsidize dominant local generators more than nodal markets.

Despite the strong support for LMP pricing among electricity market design experts[5], there are other market design elements intrinsically linked to LMP that must be decided upon. We discuss five elements in this section. Two elements in the model discussed in the Consultation Paper concern us: The treatment of load prices and the distribution of intra-regional settlement residues. A third consideration about how to integrate transmission losses in an LMP market design is not explicitly discussed in the Consultation Paper but is relatively straightforward. A fourth consideration is how to treat storage owners under LMP, which again is straightforward. Finally, the decision on the release of information relating to the realised prices under LMP is straightforward but is not a key driver of any such reform.

### *1) Load pricing*

There are both efficiency and distributional equity questions in play when considering load pricing. In principle, load could also pay their locational marginal price. However, this is not a model observed anywhere in the world. As noted in the Consultation Paper, there are potential benefits to having all loads in a given region facing the same wholesale price. First, having load face the same price helps with the coordination of futures markets, because there will be depth among the physical participants facing that price. Second, for distributional equity, it may desirable for rural and urban customers to face similar wholesale prices.

To the best of our knowledge, loads in every nodal electricity market around the world face load aggregated point (LAP) prices. The LAP price is a load-weighted average of the locational marginal prices in a region. Our support for introducing locational marginal pricing to the NEM is conditional on load facing a LAP price, in step with market designs around the world. Theoretical research also highlights potential competition benefits from LAP pricing (Tangeras and Wolak, 2018). We are concerned that there will be unintended consequences from having load prices be set by the LMP at the regional reference node.

The first concern relates to the existing "disorderly bidding" concerns that we have observed in the NEM under the existing zonal market design. We have seen examples of generator owners bidding in a "disorderly" fashion when there is intra-regional congestion because they are compensated at the regional reference node price, which is not equivalent to the marginal value of energy at their own node. Similar incentives will remain under a nodal market design where load faces the regional reference node price because of two reasons:

> 1) Vertically integrated gentailers may still have an incentive to use their market power to influence the regional reference node price.

[4] Wolak (2018) states that, "Almost any difference between the market model used to set dispatch levels and market prices and the actual operation of the generation units needed to serve demand creates an opportunity for market participants to take actions that raise their profits at the expense of overall market efficiency." Refer to the "DEC" game in California's zonal market during 1998-2006 (citation) or the examples of "disorderly bidding" in Australia's National Electricity Market attached to the Consultation Paper or in AER (2013).

[5] For example, see Hogan (1999), Wolak (2018,2019) and Cramton (2018) and references therein for discussions about the benefits of nodal pricing, with Wolak and Cramton stressing the importance of sound market design with the growing penetration of renewables.

2) Under the proposed model where each generator owner receives a share of the intra-regional settlement residue, they have an added incentive to induce congestion into the regional reference node.

In both cases, there is the potential for these strategies to shift the as-bid merit order in a way that is efficiency degrading. Generators in a position to exercise market power to influence the regional reference nodes may have incentives to do so that could result in unintended consequences.

The second concern relates to the balance of payments collected or paid by the market operator. Under a LAP, total payments for energy by loads being must be greater than or equal to the payments received by generators. Therefore, the market operator collects a merchandising surplus (the sum of the intra- and inter-regional settlement residues discussed in the Consultation Paper). A policy decision must be made as to how to redistribute the merchandising surplus. However, under LMP with loads facing the regional reference node price, there is no guarantee that the merchandising surplus will be positive. Indeed, as the penetration of distributed generation increases, power flows may change such that there could be times of day where energy is exported from the regional reference node to other parts of the network. In such circumstances, the load price will be less than the generation node prices throughout the network and a mechanism must be designed to recover this missing revenue. Any cost recovery rule is likely to be arbitrary and distort incentives away from what might be efficient. It is difficult to predict the problems that can occur under this market model, so we think it is best to design the market to avoid this unnecessary circumstance at the time of introducing an LMP market design. If not, it is all but guaranteed that negative settlement residues will occur with some frequency under the proposed model in the Consultation Paper, and therefore it must be accompanied by another policy rule that could further distort the market.

### *2) Distribution of settlement residues*

As stated in FERC (2002) in their framing of a standard electricity market design, the issue of how to allocate transmission rights is difficult and contentious. When there is congestion in the network, it results in loads paying more for their energy than the revenue generators receive for their output. This difference is a settlement residue collected by the market operator in settling the market transactions and all electricity market policy makers must decide what to do with this surplus. Usual approaches are to either directly allocate these revenues to load or auction the rights to these revenues. In the U.S. electricity markets, these revenues are used to underwrite a collection of financial transmission rights that could be used by market participants to manage basis risk arising from forward contracting in a congested network.[6] Theoretical and empirical concerns arise with many of the aforementioned policy options and need to be carefully considered.

First, there is the theoretical concern that generators in possession of certain financial transmission rights (FTRs) or equivalent instruments could be incentivized to exercise market power to the detriment of market efficiency. An FTR pays the holder the price difference between two nodes, therefore, a generator holding an FTR at one of the nodes can influence the payout of the FTR via their behaviour in the wholesale market. In an auction setting, Bushnell (1999) cautions that it could result in the derivatives “flowing to those that can abuse them the most.”

This market power concern is maintained under the proposed rule in the Consultation Paper: to allocate settlement residue rights to generator owners based on their installed capacity. To the extent that generators can influence the wholesale prices paid by load, this could provide incentives for some dominant generators to induce congestion and push prices up in the congested regions, in order to increase the value of their financial position from their share in the settlement residue.

Second, an empirical concern has been documented in many markets that auction FTRs – the FTRs tend to sell for much less than they pay out. This has been a focus of a U.S. Congressional hearing.[7] There is nothing inherently wrong with firms making profits from their financial positions, but there are questions as to whether these are efficiency improving outcomes or just a transfer of wealth from the ratepayers that effectively fund the auctions.[8] In California, a recent rule change has limited the sets of location-pair FTRs that firms can purchase at auction in an attempt to limit these transfers of wealth, refunding the rest to ratepayers.

The NEM already has a mechanism for distributing the inter-regional settlement residue (IRSR) that accrues when there is congestion between regions. Through a series of share auctions, market participants can buy the rights to the IRSR that accrues between two regions in a future quarter. However, Leslie and Wolak (2019) document that the rights to these revenues have sold for 42% less than their eventual payout since the inception of the NEM in 1999 through to 2018. This is curious because if these instruments were used to hedge wholesale market exposures of participants one might expect them to sell on average for more than their eventual payouts. Under the existing market design, this may represent a transfer payment from electricity customers to rights holders. From Leslie and Wolak (2019):

> *Transmission ratepayers (consisting of electricity customers) pay transmission owners their revenue requirement, set ex-ante by the Australian Energy Regulator. This projected requirement covers the costs of efficiently maintaining reliable lines, plus a return on their investment AEMC (2017). The IRSR auction revenues are used to partially offset this payment (See AEMC, 2018 section 6A.23.3(b)1) - therefore the ratepayers pay for open access and maintenance for the transmission lines and the rights to the IRSR which are then auctioned. Transmission ratepayers do not have a choice whether or not to auction these derivatives, and can be considered an unwilling counterparty to the derivatives sold and issued at auction.*

Although allocating settlement residues to rights holders (or auctioning them) could provide hedging instruments that are useful for some participants to manage their basis risk arising from network congestion, we recommend further consideration before deciding on such a rule. More research is required to understand the market efficiency benefits (or costs) from either policy rule and whether it would be fairer to simply refund the settlement residues to load. We are uneasy with the proposed allocation model on both a market efficiency and fairness basis. Transmission ratepayers pay the embedded system costs and have a strong claim to the merchandising surplus. We consider it instructive that in FERC's standard market design working paper only two considerations are mentioned. From FERC (2002, p.8):

> *One option is to directly allocate the transmission rights to customers that pay the embedded costs of the system. Any transmission rights not claimed by these customers would be auctioned. Another option would be to conduct an auction to apportion the transmission rights, with the proceeds from the auction allocated to those customers that pay the embedded costs of the system.*

Recommendations and considerations regarding the distribution of settlement residues

1) Evaluate the performance of the existing IRSR auctions. Leslie and Wolak (2019) document the outcomes from the IRSR auctions but are unable to comment on the efficiency consequences without the release of information as to which market participants are winning the IRSR rights. Releasing this data or commissioning an analysis would be a prudent step to ensure that the source of the profits is not efficiency degrading behaviour and to better evaluate the role of these instruments in the hedging portfolios of market participants.
2) Under a nodal market design, it seems preferable to have a unified policy for inter- and intra-regional settlement residue. As it stands, with access to well-traded futures markets for zonal products, there does not appear to be a strong argument for the auction of inter-regional settlement residue rights because markets are forming for similar hedging instruments on the Australian Stock Exchange. However, in an LMP market setting, we would not expect futures markets to form for prices relating to each node in the network.
3) As a placeholder for how to distribute the intra-regional merchandising surplus, we recommend it be refunded to load on a load-weighted basis. This is because the settlement residue accrues when load pays more than generators receive in the wholesale market and the load-weighting share means seems a reasonable apportioning. This seems preferable to allocations to generator owners based on their existing capacity because of the potential for perverse incentives including a) the exercise of market power to increase the value of financial positions (discussed above) or b) inefficiently installing capacity to receive settlement revenue rights.
    a. There may be a case for allocating a portion of the merchandising surplus to plan transmission network transformation, but such an idea requires further development. Parts of the network generating the merchandising surplus could signify the worthiness of studies assessing the long-term value of augmenting the network. However, we recognise that if such studies are worthwhile it might be more suitable to fund them by other means.

### 3) *Marginal loss factors*

A uniform marginal loss factor applied to a given node is an arbitrary rule that does not respect that the economic value of actions in the electricity market changes across time and space. The losses apportioned to generation at a given node can vary throughout a day. Load patterns will become more variable as distributed energy resource penetration continues. Therefore, any move to LMP pricing should have a congestion and loss component to the locational price at each node in the network, to further improve the efficiency of the price signals. This is a common model used internationally.

### 4) *Prices for storage owners*

The private incentives for storage owners are predicated on the ability to buy low and sell high. Under LMP, the efficiency benefits from their buy and sell decisions are directly linked to the LMP at their location. Therefore, storage owners should be treated differently to load when withdrawing energy from the network and pay the locational marginal price at their location. The LAP price discussed earlier should be aggregated over load excluding utility scale storage connected directly to the distribution or transmission network. It is recognised that it may not be practical to exclude storage devices connected behind the customer meter.

### 5) *Information benefits from LMP*

Locational marginal prices can be used to identify valuable locations for new investment. However, by definition, marginal price signals are mostly informative for marginal investments such as small and medium scale storage, generation or demand side programs. This is not to say the information is without value, but this does not markedly shift the tools available to value transmission investment which occurs at scale. We support a full sunlight policy of publishing all market outcomes for the public to access, regardless of market design. This would include full historical results, not only a rolling 12-month historical window that is currently available.

## Summary response to dynamic regional pricing

We welcome and conditionally support locational marginal pricing (LMP). We stress that there are numerous examples of LMP market models that have been implemented around the world that we should learn from when designing the NEM model.

We are concerned about the model in the Consultation Paper that charges load the regional reference node price and recommend load aggregation point (LAP) pricing. Given that LMP market designs are observed around the world, we are in a position to learn from these markets and it is likely that departing from the models observed around the world will be counter-productive because they have had time to iron out any issues with their LMP model. We are also concerned about the allocation of settlement residues to generator owners based on their installed capacity and believe that there is a considerable potential for unintended consequences. We recommend further research and consideration about how to allocate the settlement residue and recommend as a placeholder that it is refunded to load on a load-weighted basis.

We also recommend that any introduction of LMP should include a loss component that also varies over time and space as discussed in Bohn, Caramanis and Schweppe (1984) and observed in LMP markets internationally. Further, storage owners should face their locational marginal price when both charging and discharging. Finally, we support a full sunlight policy of publishing all market outcomes for the public to access, regardless of market design.

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[6] See Leslie and Wolak (2019) for a simplistic overview of contracting in nodal markets.

[7] See United States House of Representatives Subcommittee on Energy (November 29, 2017): “Hearing on “Powering America: Examining the Role of Financial Trading in the Electricity Markets”,” 115th Congress.

[8] See Leslie (2018) that explores the performance of FTR auctions in New York’s wholesale electricity market. He finds that majority of profits are earned by financial traders. Also, refer to CAISO DMM (2016,2017) for details on outcomes in the Californian market.

## Transmission investment funding: Using firm transmission rights to solve coordination problems in investment and generation

This section expands on the opening summary and is the response to Question 4 in the Consultation Paper: *What issues and considerations should the AEMC take into account when developing and assessing phase 3 (generators fund transmission infrastructure).*

It is difficult to give a clear answer to this question without a clear picture of the market or regulatory failure such reform is aimed to address. The motivation appears related to developing transmission for Renewable Energy Zones (REZs), and the non-utilisation of the scale efficient network extension (SENE) to coordinate transmission investment. However, if SENE and the FTR model are designed to overcome shortcomings in the Regulatory Investment Test for Transmission (RIT-T) process, it may be best to focus policy attention to the RIT-T as the RIT-T's co-existence poses a challenge to any more merchant-type transmission models being utilised, unless there is clear demarcation as to what types of projects can be considered under each model.

Overall, we find it difficult to foresee how the FTR model will overcome market failures in transmission investment, given its coexistence with the RIT-T and the strategic incentives facing potential generator entrants. Further consideration should be given to whether this potential rule change is constructive and whether policy resources should instead be provided to improve the design or interpretation of the RIT-T process or to consider alternative means of funding transmission projects. For example, the RIT-T includes in the benefit calculation:

> *Any additional option value (meaning any option value that has not already been included in other classes of market benefits) gained or foregone from implementing the credible option with respect to the likely future investment needs of the market.*

If the framework under the RIT-T to accommodate uncertainty and coordination problems due to different investment horizons for transmission and generation are resulting in this option value (or other aspects of the RIT-T) being discounted beyond what is reasonable, then this framework is what needs to be reconsidered.

The rest of this section considers the key benefits and challenges in an FTR model of developing transmission infrastructure.

### *Ideal benefits from the FTR-based model*

Having generators face the costs of the transmission investments has a number of attractive features from the view point of facilitating efficient long run investments but is not without its challenges. Some of the attractive features of the proposed change:

- Generator owners face the cost of the transmission investments required to provide access for their sites to the grid. The transmission costs are a relevant cost that should be incorporated into generator siting decisions.
- This is likely to result in lower long run electricity prices through more prudent investment decisions and by shifting some of the financial costs of transmission investments away from load customers and on to generators.
- The entities that fund the transmission investment are granted the FTRs. FTRs capture a component of the benefits associated with a transmission investment. Allocating these to the entities that fund the investment serves to better align the incentives of those making these investments, resulting in more efficient decision making.

### *Challenges inherent in the FTR-based model*

#### Co-existence with the regulated asset model

A change in the market rules to allow generators to receive financial transmission rights (FTRs) when they fund a transmission project seems unlikely to result in substantial changes to the transmission network.

- If a transmission project is funded by generators via FTRs then it most likely would have satisfied the conditions of the RIT-T. The revealed actions of generators coordinating to develop transmission demonstrates that the collective rents they collect from the economic value generated by the project is likely to signal that the net economic benefit is positive.

- But all else equal, generator owner(s) prefer the RIT-T mechanism because approved projects are recovered from transmission customers, so the generators won't have to self-fund the investment and it can compete purely on the value of energy as do all incumbent generators.

Merchant transmission investment (private funding of transmission projects in exchange for FTRs) has been an alternative means of funding transmission projects in many jurisdictions around the world. It has typically existed in conjunction with a regulated process. We are not familiar with many examples of this type of funding mechanism leading to investments in practice. There needs to be a clear definition of what types of transmission investments are eligible under each process because generators and TNSPs are likely to prefer that a project is approved through the RIT-T mechanism.

### Competition for transmission development

If regional transmission network service providers are the only entities that generators can engage with, these entities might be able to capture all rents generated from the project.

- The potential to introduce competition into the provision of transmission investments within the planning process might be considered. We believe this is consistent with minimizing the costs of any transmission infrastructure that is constructed. There is some existing experience with this approach in a regulated environment around the world and some promising early signs about its efficacy. Joskow (2019) documents the experience in the US with this form of transmission procurement, noting that "If we view the evidence to date … it suggests that there are potential efficiency gains from expanding open competitive solicitation opportunities meeting certain criteria." We believe that there is scope for incorporating some of the features of competitive procurement to reduce the costs faced by generators for the funding of transmission.

### Strategic incentives and other frictions

The process that determines the scale of the transmission project and the costs/FTR allocation for generators faces a number of challenges for achieving efficient outcomes. We believe that any design needs to account for the strategic behaviour of participants:

- Non-excludability and potential for free-riding:
  - As noted by Gans and King (2000) when transmission investments are lumpy then the allocation of FTR does not capture the total economic surplus generated by the investment. This means that the allocation of FTRs to the funders of transmission infrastructure will tend to result in under provision.
  - Moreover, the surplus not accounted for by the FTRs is an economic spill-over to other participants and may create a strategic incentive for some generators to free-ride on the investment in transmission infrastructure funded by others.
- Economies of scale in transmission investment and first-mover disadvantage:
  - Scale economies mean that the first increment of installed transmission capacity is more expensive and has longer lead time than subsequent expansions. This may create a first-mover disadvantage and result in strategic delay of investments as generators wait for others to make the initial investment.
- Asymmetric information:
  - A general observation about mechanisms where participants hold informational advantages (e.g. generators may know the costs, economic value of some resources better than others) is that participants will try to take advantage of these for their own benefit and this type of strategic behaviour may be a barrier to achieving efficient outcomes.
- Absence of future generators/market participants:
  - The significant gap in planning horizons for new transmission lines on new easements (5-8 years) relative to new renewable generators (1-3 years) may mean that some participants that may benefit from a new transmission investment may not participate in the initial process that determines the scale of the investment. As a result, their demand for the investment may not be captured in any proposed planning mechanism/process and the resulting scale of the investment may be inefficiently small.

- Some consideration should be given to how to handle the financial risks that arise after funding obligations and FTR allocations are determined. For instance:
    - In the event that a generator defaults on a financial obligation who is responsible for the funding shortfall or losses incurred by other participants as a result of this?
    - Which party holds the risk of cost over-runs during the construction process?
    - Are there provisions that provide incentives for the builders of the transmission infrastructure to minimize the costs?

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