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26TH APRIL 2019

To: AEMC
By online submission
Reference: EPR0073

Re: **Response to Coordination of generation and transmission investment implementation – access and charging**

Infigen Energy (Infigen) welcomes the opportunity to make a submission to the ISP. Infigen owns a 670 MW portfolio of wind capacity across New South Wales, South Australia, Victoria and Western Australia, is constructing a 25 MW / 52 MWh battery in South Australia and has entered into PPAs to provide an additional c.57 MW of capacity in Victoria.

Infigen supports the AEMC's efforts to investigate reforms that would help coordinate generation and transmission investment, but cautions that more data is required to assess costs, benefits, and unintended consequences vis-à-vis forward market liquidity, resulting in rising costs to consumers. Furthermore, given the overlap (and potential competition) between these transmission reforms and the ESB's broader package of market reform work, it may be appropriate to delay decisions on transmission until such time as greater certainty of other market aspects is available.

Our submission provides some high-level comments, followed by addressing the AEMC's individual questions (which expand on the high level comments below).

Maintaining supply of forward contracts and financing

Given the potential magnitude of the proposed reforms, great care should be taken not to distort or damage financial and forward contract markets specifically in relation to hedging liquidity. We see there is a significant risk that the greater complexity around managing a "three part" risk (congestion, local marginal price, and settlement residue) will reduce the willingness of supply-side participants to offer primary hedge capacity, at least in the medium term. This may increase hedge premiums/costs to consumers.

Similarly, a move towards charging existing generators for transmission would threaten existing investments and increase the perception of investment risk in the NEM through effectively retroactive rules, increasing future funding costs.

Conversely, any attempts to grant incumbents firm access to the existing network may slow the development of new generation.

Need for more detailed information and cost-benefit analysis

A version of the proposed dynamic regional pricing (effectively, nodal pricing) and firm access proposals were considered previously under the Optional Firm Access (OFA) review. At the time, the benefits were found to be low, and with significant challenges around fairness, but given the current transition to a low emissions grid it is appropriate to revisit those assumptions.

We note generators already trade-off resource quality, transmission access, construction costs, network losses, regional pricing, and other factors when determining where (and when) to build. While new competing projects in the future (leading to greater constraints) is a risk, it is not necessarily more material than other project risks. Furthermore, project developers (and more importantly, project banks) do not assume constraints will be built out to reduce congestion, and allowing for some level of competing future projects is a necessary part of project development. It is not obvious that effectively forcing the parallel development of transmission with generation will reduce overall costs, as discussed further below.

We recommend that the AEMC conduct forward looking analysis of the projected level (and cost) of constraints, including identifying real-world constraint scenarios (rather than simplistic radial constraints) that can be discussed. This would include identifying the specific grid locations that the AEMC consider would be inefficiently developed under current frameworks.

1. QUESTION 1

QUESTION 1: PHASING OF ACCESS REFORMS

1. Is our proposed approach to phasing access reforms appropriate?
2. Are the number and nature of the phases appropriate? How might access reform be phased differently?
3. What interactions with other market design reforms throughout the sector, and the energy transformation more generally, should be considered when developing and assessing transmission access reforms?
4. What should be taken into account when considering how to transition to these new arrangements?

AEMC's current proposed reform schedule is shown in the table below.

Phase	Overview	Timing
1. Dynamic regional pricing	The access arrangements would be changed to implement dynamic regions for determining the price payable to generators.	July 2022

2. Improved Information	The information that is produced from dynamic regional pricing, including where congestion occurs and the costs of congestion, would be used to supplement the planning arrangements for transmission.	July 2022 to July 2023
3. Generators fund transmission investment	In response to the information on network congestion, connecting parties (e.g. generators) would be able to purchase firm transmission rights or firm access to the network, which in turn would be used to underwrite the necessary network investment needed to physically provide that access. Generators' collective decisions to purchase transmission rights would guide the preparation of AEMO's ISP's and TNSPs' planning decisions due to an obligation placed on TNSPs to provide sufficient transmission capacity consistent with the rights purchased by generators.	July 2023

Infigen is concerned that the "Improved Information" stage is proposed to occur *after* the implementation of dynamic regional pricing noting that the proposed reforms occur well within the planning horizon for current projects. Information on likely zones, prices and outcomes should be developed as an input to this review process.

EY analysis for AEMC indicated that constraints are not currently a material cost. The AEMC and a number of submissions to the CoGaTI Discussion Paper suggested that back-looking analysis of congestion is not sufficient – but to date no forward-looking analysis has been undertaken by the AEMC or AEMO to determine the *materiality* of future congestion. As noted by the AEMC, given the cost of perfect spatial coverage in the NEM, some level of congestion is efficient for consumers and, potentially, even for generators. An analogy is the oversizing of DC solar capacity compared to its AC inverter capacity.

Infigen recommends that:

- The AEMC work with AEMO or a consultant (or both) to provide a detailed public report on current congestion in the NEM, including analysis of existing connection points that are currently affected by transmission constraints and the resulting local prices under dynamical regional pricing. Infigen understands that much of this analysis is already produced in NEMDE.
- Potentially in conjunction with AEMO's ISP, provide analysis of emerging congestion and dynamic regional pricing impacts, including where congestion is projected to occur (and why, including whether a permanent market failure is emerging that requires some form of policy intervention). This should consider both a middle of the road scenario, as well as a rapid decarbonisation scenario.

Real world analysis and examples will be essential for industry to be able to effectively comment on the proposed frameworks, and will help inform industry on the materiality of the changes.

We also note many competing projects are underway (e.g., the possibility of capacity markets under the ESB's Post 2025 Market Design work); the current implementation may not be appropriate if other aspects of the market change. It may therefore be more appropriate to delay changes to the transmission framework.

2. QUESTION 2

QUESTION 2: PHASE 1: DYNAMIC REGIONAL PRICING

1. What is the nature of the risk on generators from being settled at the dynamic regional price in the event of congestion? To what extent is this risk different from (and greater or less than) the current risk to generators of being constrained off/down in the event of congestion? What impact may these changing risks have on the contract market, both in terms of products, liquidity, and risks businesses are exposed to?
2. Is generator capacity an appropriate metric on which to allocate the settlement residue which arises from dynamic regional pricing? If not, what alternative metric should be used? Which particular measure of capacity should be used (e.g. nameplate capacity, maximum output in previous X years)? How might the use of capacity or another metric create distorted incentives for generators and/or storage devices?
3. Should storage, when importing from the grid, be settled at the dynamic regional price? What might the effects of this be?
4. What issues or unintended consequences might arise?
5. What are the nature and extent of implementation costs, such as system changes (e.g. settlement reallocations), that would be required to implement phase 1?

Risk on generators

In the short-run, dynamic regional pricing will not change the total amount of money being paid to generation behind a constraint once settlement residues are distributed. However, to the extent that this leads to different settlement outcomes, this could put existing investments at risk. Further, changes to settlement arrangements behind a constraint do not affect consumer surplus in the short-run. Therefore, for this change to contribute to the NER, it needs to be considered for changes to long-term generation development incentives.

We note, however, that this proposal will significantly increase the complexity of risk management – moving from a single, well understood risk (congestion) to three interrelated risks (congestion, local price and settlement residues) will undermine the contract market.

It is not credible that affected generators would offer the same level of supply of hedge contracts, at least in the short to medium term. Holding all else constant, a contracting supply of hedges will have material impacts on retailer hedging costs.

Furthermore, there is already a steep learning curve for investors in energy markets. Congestion due to constraints can be explained relatively easy to project banks and equity investors; the introduction of potentially hundreds of distinct nodal prices (and associated residues) may increase apparent – if not actual – risks. Making markets even more complex risks raising the cost of capital for all industry participants as investors become increasingly weary of the ‘black box’ behaviour of the NEM. This is particularly true for real-world projects subject to multiple meshed-grid constraints: simple models of nodal pricing do not readily apply.

The AEMC’s examples[1] show that dynamic pricing may reduce one type of strategic bidding, and thereby strengthen economic signals for generators behind constraints[2]. It seems unlikely, however, that dynamic pricing on its own would improve locational/congestion signals for multiple projects with very similar production costs (i.e., wind and solar farms).

Longer term, dynamic pricing would introduce a different dimension of revenue risk, with project revenue being contingent on congestion and nodal price (as well as marginal loss factors, wholesale price, and any curtailment during zero or negative price periods). This may affect how settlement arrangements are expressed in contracts.

Fairly apportioning settlement residue

We recognise that, if load and generation is to be settled on a different basis, that some form of settlement residue allocation will be required.

Settling purely on the basis of nameplate capacity (or average historical output, etc.) is problematic and may lead to inefficient and unfair outcomes.

For example, consider the arrangement in the figure below, with an oversized wind farm[3] and an indicative peaking plant behind a constraint. When the RRP is less than the bid (theoretically, the short-run marginal cost) of the peaking plant, current market arrangements deliver the least-cost dispatch. It would not be appropriate for the peaking plant to receive a share of the revenue.

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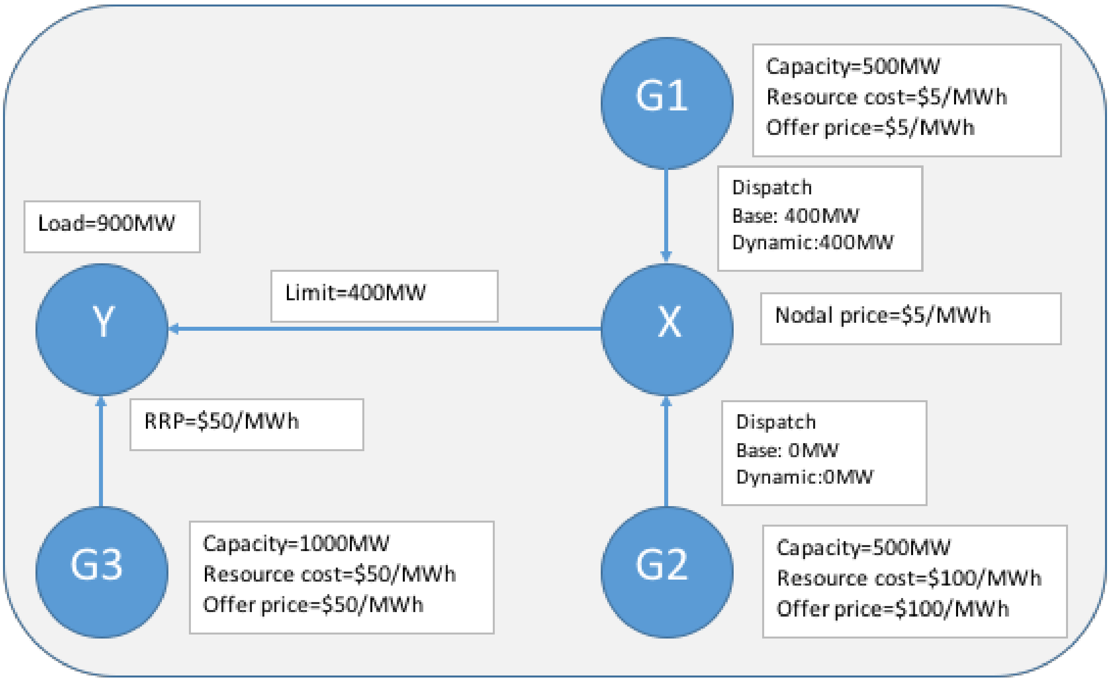
[1] Section 6.1.2 of CoGaTI Final Report

[2] That is, dispatch moves closer towards fuel cost merit order and incentivising a more efficient structural and locational mix of capacity.

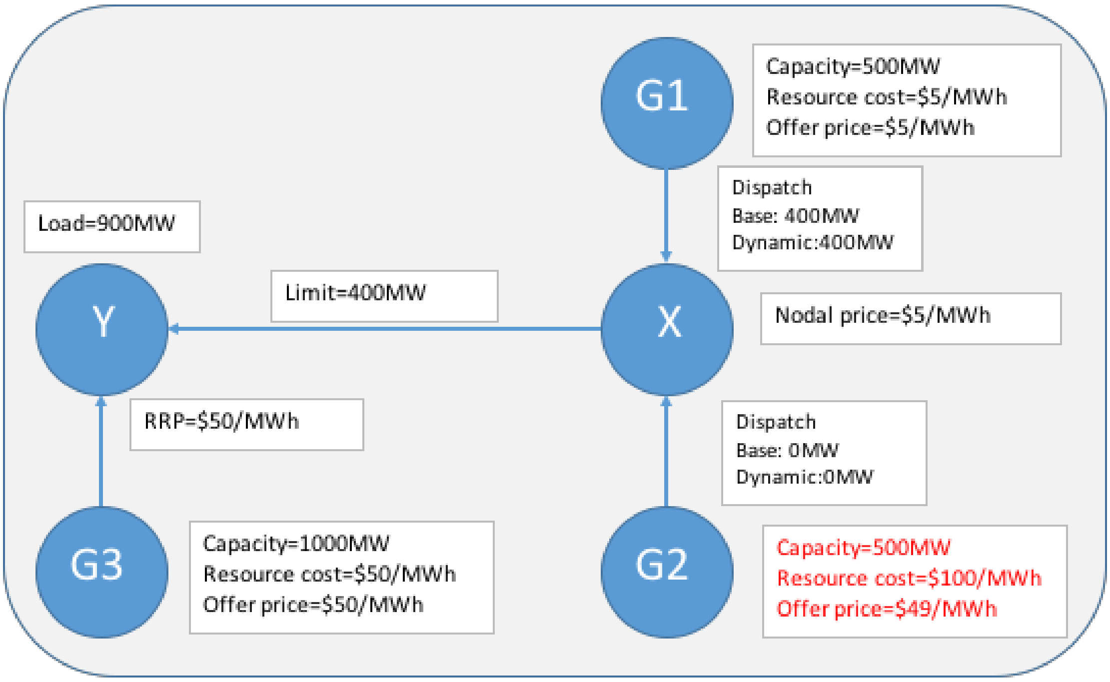
[3] This could be multiple wind farms behind a constraint, or a single wind farm oversized. It’s possible that some level of transmission constraint will be a least-cost solution in the future, given generation-duration curves, similar to the current oversizing of solar MWdc to MWac. It is also credible that peakers might share transmission with renewable generation, since their output will *tend* to be anti-correlated in the future.



Alternatively, if residues were paid to all generation with a bid below the RRP, there would be an incentive for the peaking plant to shadow-bid the RRP (shown below) such that it would have been dispatched had the constraint not bound. Such strategies may not be stable (G1 could bid above the RRP, forcing G2's physical dispatch), but it highlights that strategic bidding is likely to still exist.

In specialised cases, a peaking plant might even be incentivised to manufacture congestion – bid to be dispatched below its SRMC, in order to create congestion and receive a settlement residue. This was possible under the original OFA proposal[4].

[4] See Riesz, Gilmore & McGill working paper on OFA, section 3.2 http://ceem.unsw.edu.au/sites/default/files/documents/CEEM%20submission%20to%20OFA%20First%20Interim%20Report%202014-09-04a.pdf



Infigen has not assessed the materiality of these scenarios, so it would be helpful to have some real-world examples to consider (as noted under Question 1).

In practice, constraints often involve many generators across the meshed network – complexities around which specific constraint binds in a given period could have significant implications for which participants receive the residue compensation. The geographically delocalised nature of some constraints could lead to counterintuitive results.

Storage

There would seem to be strong arguments for settling energy storage at the dynamic regional price: this would provide incentives for storage to locate where it would access lower cost energy (and hence deliver additional system benefits). If storage were settled at the nodal price, this efficiency would be lost and locational signals for energy storage would be muted.

We note this argument also true for all loads. For now, energy storage is typically more responsive than loads and so benefits may be more material, but this could change if significant demand side response enters the market.

Implementation costs

The IT costs associated with a further change to settlement arrangements should not be underestimated. Businesses are already responding to 5 Minute Settlement which requires as 6-fold increase in data. Coupled with separate price streams for every generator, plus settlement residues, this may require qualitative changes to data management systems for some retailers.

Updating existing long-dated contracts will also require significant technical and legal input.

3. QUESTION 3

> **QUESTION 3: INFORMATION FROM DYNAMIC REGIONAL PRICING**
>
> 1. What information is likely to be revealed through dynamic regional pricing?
> 2. How valuable is the information from dynamic regional pricing likely to be in the various transmission planning processes? Will it have other uses?
> 3. How should the information revealed by dynamic regional pricing be revealed to the market?
> 4. How might AEMO, TNSPs and the AER integrate the information into their processes?
> 5. Should the rules be modified to require these parties to take this information into account, and if so, how?

AEMO would need to publish all dynamical regional prices in its pre-dispatch data sets. To the extent that dynamic regional pricing leads to different physical outcomes, this would clearly need to be incorporated into modelling and analysis studies (e.g., to track emissions, financial impacts, etc.)

4. QUESTION 4

> **QUESTION 4: GENERATORS FUND TRANSMISSION INVESTMENT**
>
> 1. What issues and considerations should the AEMC take into account when developing and assessing phase 3?

Providing generators with an option to purchase firm access is a complex framework, and Infigen looks forward to engaging with the AEMC to ensure a robust outcome. We note that many of these issues were explored in great depth through the OFA rule change process, and AEMC should reference and make use of this analysis and stakeholder feedback to save time in this process.

Treatment of the shared network

Infigen's view is that access to the existing network should continue to remain open, and generation should not be eligible to purchase firm access of existing capacity, as consumers have paid (and continue to pay) for this network. If existing generation was (implicitly or explicitly) required to pay for firm access, this could materially impact existing investments given balance sheets have been structured to deal with NEM Rules which have been in place for two decades. Such a material change is likely to undermine investor confidence, increase financing costs, and could potentially produce financial distress events in the short run.

Conversely, as noted by many stakeholders under OFA, attempts to grandfather access represents a significant advantage to aging incumbents, and risks inhibiting the transition to a low emissions grid[5].

There are roles for generation to fund *new* or *upgraded* transmission and get sole or divisible access to it (physical or financial) where such access does not disadvantage existing generation (i.e., other generators are indifferent to one or many generator's decision to purchase firm access). This could be particularly applicable to new Renewable Energy Zones, but can also potentially be managed under existing frameworks.

Realistic examples of network constraints

In practice, generators are not on simple radial networks: the NEM is a heavily meshed network where constraints are distributed and non-local. For example, some constraints can include a majority of generators in the region on the left-hand side. Providing firm access may inevitably require allocation of property rights on the shared network, leading to the same challenges of grandfathering identified in OFA and wealth transfer from consumers to incumbents (or, alternatively, new costs on incumbents).

It may be worth considering comparisons to the gas network: each pipeline is comparatively distinct, allowing for clearly defined firm access to be sold. However, recent reforms have identified that this approach is *inefficient* and have established mechanisms for trading unsold or unused pipeline capacity.

It would again be helpful to provide some practical examples of how this package of reforms might improve system outcomes, and how participants are likely to use it. For example, a wind farm is unlikely to need firm access for the entirety of its output, or at all times. There are also benefits when multiple projects sharing the same line: this could include two wind farms with complementary generation patterns, a wind and a solar farm, or a wind farm with a GT or battery. The last example is particularly pertinent: the times when the GT/battery would be most required are likely to be times of low wind generation and when there wouldn't be congestion. The current open access framework facilitates this type of arrangement, while firm access may drive further horizontal integration to make best use of "private" network access.

The AEMC notes that, *"Under a firm transmission access regime, where generators make inefficient investment decisions, they would bear the cost of any expansion of the transmission network that was undertaken to give them firm access."* However, depending on how firm access is ultimately delivered, it may be that TNSPs – and ultimately consumers – bear significant risks if changing transmission flows (e.g.,

[5] See for example http://ceem.unsw.edu.au/sites/default/files/documents/CEEM%20submission%20to%20OFA%20First%20Interim%20Report%202014-09-04a.pdf

reductions in load due to distributed resources) lead to additional constraints that must then be built out (or paid for through financial settlements).

Coordination of generation

Firm access does not seem to address the broader coordination problem of correctly sizing transmission upgrades; arguably, allowing transmission to follow generation may be better at identifying optimal locations for generation.

AEMC suggested in the Supplementary Information Paper that firm access could help to facilitate information sharing by reducing competition for a given transmission resource. This will depend strongly on how firm access pricing is considered. Under OFA, there was significant first mover advantage (gaining access to the existing network). Even if all parties receive the same firm access costs, there are other commercial reasons to not share project information ahead of time.

We also note that AEMC's clarifications on REZ's is still unclear – any firm access pricing for a prospective REZ would presumably be dependent on multiple parties connecting; TNSPs would seem to still be necessarily taking on risk if they commit to connecting a single party at a fixed price. The coordination issues remain.

5. SOME OF THE MATERIAL POINTS THAT SHOULD BE CONSIDERED BY THE AEMC ARE OUTLINED IN APPENDIX A BELOW (ACKNOWLEDGING THAT THE AEMC IS ALREADY WELL VERSED IN THESE ISSUES THROUGH THE OFA REVIEWS).QUESTION 5

QUESTION 5: ACCESS REFORM TIMEFRAMES

1. Are the timeframes suggested for the access reforms appropriate?
2. Is the timing of the phases appropriate?

We recognise that there is significant capacity likely to be developed in the NEM over the next few years, and so any benefits of this reform are likely to be amplified the earlier it is implemented (though the same is possibly true for costs). The proposed implementation timeline is fast, particularly given the implementation of 5 Minute Settlement, but manageable. We note there could be material changes required by AEMO to manage the data and systems; the 5 Minute Settlement framework provides a guide as to the time required for establishing data exchange formats, etc.

These comments are contingent on the firm access reform only applying to *new* transmission development, and not to the existing shared network.

The interaction between firm access and any proposed changes to the energy-only market would also need to be taken into account.

6. CONCLUSION

We look forward to the opportunity to engage with the AEMC. If you would like to discuss this submission, please contact Dr Joel Gilmore (Regulator Affairs Manager) on joel.gilmore@infigenenergy.com or 0411 267 044.

Yours sincerely

Ross Rolfe AO
Managing Director

APPENDIX A – FACTORS TO BE CONSIDERED AROUND FIRM ACCESS

A non-exhaustive set of discussion points are provided below.

Under what circumstances would firm access be available?

- Would participants be eligible to purchase capacity on the *existing* network, or shared network capacity building under a RIT-T?
  - Infigen is opposed to participants buying firm access on the existing network, as the existing network has been built for the shared access of all participants. Existing plant capital commitments did not envisage major changes to access. If existing projects were forced to compete *financially* for existing access to transmission with new or other existing projects, this may undermine existing investments (potentially with costs that cannot be recovered, or worse, absorbed without creating a financial distress event).
  - This and the related idea grandfathering access was highly problematic under OFA, and represents a barrier to the transition to a low emissions future[6].
  - We note that the pricing of firm access on the existing network is particularly problematic (with questions around marginal vs average costs, tenor of purchases, etc.) and were discussed in great detail under OFA. For example, the marginal cost of providing firm access might be zero (if there was spare capacity), but this would represent

[6] See for example Riesz, Gilmore & MacGill http://ceem.unsw.edu.au/sites/default/files/documents/OFA%20Working%20Paper%20-%202014-05-15a.pdf

an effective transfer of property rights (of network paid for by consumers) to that generator[7].
    - Providing firm access to the existing network also requires consideration of a “queue” of new connections.
    - Notwithstanding the above, if the AEMC did choose allow firm access to be purchased on the existing network, it should be for only short tenors (e.g. one to three years to match forward market commitments) to allow maximum flexibility in the system.
- How long would firm access contracts be offered for?
    - Shorter duration contracts may not materially change investment risk, while long duration contracts could significantly hamper the transition of the energy sector
    - This is particularly true if access is sold on the existing network (which Infigen does not support). Transmission access is a valuable resource, but is unlikely that all potential buyers are ready to bid at the same time. Long-dated contracts would exacerbate the first mover advantage.
- How would this change facilitate Renewable Energy Zones?
    - To the extent that new entrants are currently unable to fund new transmission (or, more likely, transmission upgrades) for their dedicated use, it is not clear how firm access will resolve this.
- How would TNSPs size any new transmission assets?
    - If TNSPs are forced to build incremental assets for each new connection, this may be higher cost than if transmission follows generation. Western Victoria could provide a useful case study: what would the costs have been if there was no coordination between participants, but the TNSP had been forced to provide firm access to each project?
    - Conversely, if TNSPs size expansions based on anticipated (but not yet committed) projects or even on submitted but not agreed firm access applications, it may create new investment risks.

Pricing and eligibility

- How will the cost of firm access be determined?
    - While the cost of upgrading a radial line from the reference node to provide firm access is relatively clear-cut, in practice providing firm access requires consideration of a broad range of constraints and how these could be built out.
    - Similarly, how would deep upgrade costs be assessed and valued, and by who?
    - If prices are determined through auction, the small (potentially zero, one or two) number of players (who are most likely unknown to each other) would make determining commercial bids challenging.
- What review process would there be for TNSP firm access proposals, and by whom?
    - If this framework were to be implemented, it is critical for developers that there is transparency and opportunity for competitive processes for building out these constraints rather than being forced to rely on a “take it or leave it” proposal from a TNSP.

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[7] Ibid.

- Would consideration of future consumer-benefit driven upgrades be considered?
    - In the previous OFA proposal, TNSPs were required to project future transmission developments (e.g., to manage load growth) and determine the NPV of the brought forward cost of the upgrade. This was a highly complex and problematic framework. It may also lead to sub-optimal construction and hence greater costs (either to the participant or to the market)
    - This also requires consideration of emerging constraints, to ensure that true opportunity costs are considered.
- What level of "firm" would the access be?
    - For example, at one extreme generators could simply be provided with a financial hedge against congestion caused by another generator; this would be the lowest cost to implement. At the other extreme, generators could be provided with firm physical or financial contracts that would expose the transmission service provider to the risk of outages or other dispatch.
- Who would bear the costs if delivering firm access proves more challenging?
    - Would this fall on TNSPs, or would consumers ultimately be required to fund upgrades/meet cost shortfalls if the TNSP initial agreement was insufficient?

Access to transmission

- If a participant purchases firm access through the development of new transmission, would other participants have "access" to that transmission in the absence of congestion, or would it be for the *exclusive* use of the firm participant?
    - How would this affect TNSP pricing?
- Providing firm access to one party might reduce result exacerbating constraints for another geographically separated party – either immediately or in the future. Given that consumers paid (and continue to pay) for the existing network, AEMC will need to ensure that any firm access provision didn't disadvantage existing or future generators.

Interaction with Renewable Energy Zones (REZs)

- How will this framework interact with REZs, and with the RIT-T framework?
- Allowing participants to purchase firm access could help new projects to build or upgrade lines without being required to share that access with a future party. It may also help avoid a future frameworks requiring speculative investments in transmission. However, see comments above on the difficulties of real-world constraints versus the AEMC's simple radial model.
- However, it does not explicitly facilitate coordination between projects to size new investments efficiently.

Interaction with RIT-T

- If a proposed transmission upgrades would deliver lower costs to consumers, would TNSPs still be able to undertake a RIT-T and build that transmission?
    - Infigen supports retaining the RIT-T for intraregional upgrades where those upgrades would result in more efficient usage of existing generation and reduce total customer costs.

    - While we acknowledging that the purpose of the proposal is to better align generation and transmission, this should not preclude cost savings being delivered to consumers.
- Would any changes to the RIT-T framework be undertaken to deter generation from waiting for a consumer-benefit led upgrade?
    - Would benefits to non-firm generation be treated differently from firm generation?