CASTALIA

Q&A Document Responding to CEIG's Proposal for Grid Access Reform

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Definitions

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
CMM	Congestion Management Model
ESB	Energy Security Board
EOI	Expression of Interest
ERCOT	Electric Reliability Council of Texas
CAISO	California Independent System Operator
CEIG	Clean Energy Investor Group
ISP	Integrated System Plan
LMP	Locational Marginal Price
MISO	Midcontinent Independent System Operator
NEM	National Electricity Market
NYISO	New York Independent System Operator
PJM	Pennsylvania, New Jersey, and Maryland
RE	Renewable Energy
REZ	Renewable Energy Zone
SRMC	Short-run marginal cost
LRMC	Long-run marginal cost
TC	Transmission Charge
VRE	Variable Renewable Energy

1 Introduction

Clean Energy Investor Group (CEIG) has received considerable engagement and feedback in response to the publication of the CEIG's "Rethink of Open Access Regime" prepared by Castalia and the presentation of the proposal to stakeholders at the "Virtual Seminar: Alternative Approaches to Congestion Management" on February 24, 2022. This Question & Answer document responds to the key questions about the proposal raised by the stakeholders.

The Question & Answer document provides responses to each key question raised in the "mural" created as part of the breakout room to discuss the CEIG/Castalia proposal during the February 24 Virtual Seminar, as well to questions addressed directly to CEIG outside the seminar. We address questions in the following order:

- Section 2: General Questions
- Section 3: MLF/ALF Questions
- Section 4: Queue Questions
- Section 5: Transmission Charges Questions
- Section 6: Tie-break Rule Change Questions

Our Question & Answer document covers both matters already addressed in the Castalia report, as well as additional detail on the proposal.

2 General questions

2.1 Would connection timeframes reduce relative to the status quo?

- The proposed access model does not directly address the issues which are currently resulting in connection delays. We recommend that the reform of the access regime be integrated with the already existing work program on improving connection timeframes. Without such integration, the connection time under the proposal would not change relative to the current timeframe
- The existing delays result from the requirement for system stability studies and the approaches adopted by TNSPs in assuring themselves that the connection would not risk system stability
- In principle, system stability requirements can be incorporated into the queue position determination process. This would not by itself change the timing of the studies but can improve the definition of the queue and can streamline the overall process.

2.2 What is the efficient level of congestion in this model?

- We believe that a small level of overbuild allows for more efficient use of transmission capacity. Naturally, with an overbuild comes a small level of congestion leading to curtailment
- In Central-West Orana (CWO) REZ, the target transmission curtailment level is 0.3 percent, based on the NSW department's modelling using publicly available information[1]
- Additionally, our consultations with stakeholders suggest that generators will be willing to accept a small level of curtailment between 1 to 2 percent. This level of curtailment would allow for efficient use of the transmission capacity without breaking the business models of most generators—in fact, most generators currently build a small amount of curtailment into their business model
- Thus, using the CWO proposal as a potential model and industry consultations, we believe that the target level of efficient curtailment is between 0.3 and 2 percent. However, this is subject to further discussion

2.3 What happens when all marginal costs are close to zero?

- In a near-zero SRMC environment, there is no social benefit to dispatching any particular unit ahead of another. However, the dispatch order—or rather the risk of non-dispatch—will remain important to each investor

1 NSW Government, REZ access rights and scheme design: Central-West Orana Consultation Paper, December 2021

- Thus, if there are no efficiency gains from competition for dispatch during each bidding period, it becomes more important to provide generation and storage investors with greater certainty about their future ability to dispatch before the investment decision. What matters is no longer the right to enter the competitive arena during every 5-minute period but rather the right to secure some degree of protection from being crowded out by generators with the same SRMC. This also comes with the obligation to not crowd out others
- In the context of a near-zero SRMC world, the Transmission Access Queue will provide long-term signals to locate where there is transmission capacity by protecting access to that capacity with incumbency rights.

2.4 How will the marginal cost of different plants be revealed truthfully through this process?

- In short, our proposal reveals marginal costs by eliminating the incentives that generators have to bid in a way that is not reflective of their SRMC.
- Under our proposal, generators would have little incentive to enter an area where their position in the queue is greater than zero because it would greatly enhance their chance of being curtailed. This, in turn, would alleviate the congestion in the area
- In the absence of congestion, generators with have no incentive to bid to the floor to ensure dispatch. In the absence of congestion, bidding below their SRMC raises the risk of being dispatched for a price below the generators SRMC. This is especially risky for thermal generators with a higher SRMC than VRE
- Thus, we believe SRMC would be revealed by eliminating incentives for generators to bid to the floor.

  We note that the SRMC of a plant in any particular 5-minute interval may vary greatly. For example, a large coal generator that must run to avoid cycling costs may have a negative SRMC (even up to the floor). We do not consider this to be disorderly bidding and our proposal would not eliminate it.

2.5 Does the incentive for storage end “behind the connection point” or elsewhere in the network?

- The question uses the term “behind the connection point”. We assume the term to mean behind the point where local transmission infrastructure joins the rest of the meshed network.
- The transmission queue is designed to incentivize the efficient location of battery storage—either stand alone or co-located—to relieve congestion on the segments of the transmission network to which the queue applies. It will signal investors to build energy storage in locations where the cost of storing energy and disbursing it when the grid is not

congested is lower than the cost of additional transmission investment required to avoid congestion or the penalty of being curtailed due to a high place in the queue.

  - For co-located battery storage, the incentive will be for investors to build enough storage that they can receive a number of zero in the queue
  - Standalone storage investments will be incentivized to locate behind transmission constraints because they will be allowed to sign bilateral agreements to purchase electricity from local generators that would otherwise expect to be constrained off. This would likely be at agreed prices below the RRP during the periods of expected curtailment. The power would then be sold when the transmission network is not constrained

- One key feature of renewable generators located in a specific area is that they are likely to dispatch at the same time as the wind blows or the sun shines. As a result, a new entrant weighing options to avoid congestion on the transmission grid and avoid a high number in the queue that will result in curtailment might consider that paying a transmission charge required to raise transmission capacity to the maximum outputs of the renewable fleet in that area might not be efficient because some of the capacity may not be utilized over 24 hours. As a result, the transmission queue will encourage the investor to consider investing in storage or signing a contract with a stand-alone storage provider as a substitute for transmission investment in a way that shifts the new entrants dispatch to a different period when the transmission grid will not be congested.
- As a result, the transmission access queue incentivizes storage to locate behind transmission constraints and help ease constraints in the transmission system by smoothing out demand for transmission capacity over the day.
- We note that the transmission queue does not eliminate other incentives that storage may face to locate in areas that do not have constrained transmission capacity. For example, the queue does not reduce the incentive to locate in areas where providing AS has a high value or where storage providers think that they can charge using cheap power during peak VRE production and discharge at a later time period when the RRP is higher. These incentives would remain intact.

2.6 How would this impact inter-regional transfers?

- We do not anticipate the queuing model having any effect on inter-regional transfers.

3 MLF/ALF Questions

3.1 What has changed regarding ALFs since the rule change determination?

- Our proposal is fundamentally different than the Adani's previous attempt to convince the AEMC to switch from MLF to ALD. We propose to retain MLFs for dispatch and to use ALF only for settlement. While we have reservations about the efficiency of MLF in determining dispatch, we propose to retain MLF for dispatch unlike the Adani proposal. Thus, a significant difference between our proposal and the previous rule change is that we suggest switching from MLF to ALF only for settlement and retaining MLF for the dispatch.
- We propose using ALF for settlement to increase investor confidence. This is because ALFs are based on observable historical data. ALFs are more predictable and would not unfairly transfer wealth from generators to customers because they are based on actual system losses. In turn, the predictability and the fair allotment of the cost of losses will increase investor confidence and lower the overall cost of capital
- Adani reasoned the need to switch from MLF to ALF based on the fact that variable MLF often undermines their investments and unfairly rewards customers. However, the AEMC held that MLFs were crucial to ensuring efficiency in dispatch. This in turn, allowed AEMC to retain MLF based on the efficiency of MLF for the dispatch. However, we propose to retain MLFs for dispatch. Thus, we think that AEMC's previous decision should be interpreted as providing precedent when considering our proposal.

3.2 Are there problematic distortions with using ALF for settlement but MLF for dispatch?

- We believe that switching from MLF to ALF for settlement and retaining MLF for dispatch would not create more distortion than there already exist in the market
- This is because by retaining MLF we would not change any bidding incentives and behavior currently observed in the market
- However, switching to ALF for settlement would reduce the over-collection of funds that goes to consumers. Most importantly, this would reduce the variability of revenue for investors, because even when there is crowding out in an area it has a significant effect on the MLF; however, it has a negligible effect on the increase of the ALF.

3.3 How critical is the use of average loss factors for the proposal, given the AEMC's decision on the Adani Rule change proposal?

- We believe that the rule change to base settlements on ALF is an important issue and should be carefully considered by the ESB.

- However, our transmission queue proposal does not rely on switching to ALFs for settlement to function. Thus, if the ESB rejected our proposal to change to ALFs for settlement it would not critically affect the rest of our proposed transmission access reform.

3.4 Average loss factors will not have revenue sufficiency at least half the time. Do TNSPs carry that burden?

- Using ALFs for settlement would mean that the IRSS would be more volatile and swing between surplus and loss. Further, the number might be large. Given that energy traded in the NEM is around 200TWH with a value of about $17billion (an average of about $330m per week); if the difference between ALF and actual losses was 5% that would equate to $16.5m per week. We acknowledge that this may create a problem for AEMO as it needs to pay generators on a weekly basis exactly the amount it receives from customers and generators need that money to settle hedges on that day.
- However, we do not think that this is an insurmountable problem because in the long run the ALF for generators and load should be equal. In any given five-minute interval actual losses will be greater or less than the average as actual generation is more or less than the average or the patterns of load and generation vary from the average. Nonetheless, it is highly likely that even over a week (2016 five-minute periods) the difference will be small. We don’t consider that the amount in any period is likely to be material.
- By design, using MLFs for both load and customers over recover revenue from customers. The difference the intra-regional settlement surplus is paid to TNSPs to reduce transmission charges. This comes about because actual marginal losses are, on average greater than average marginal losses. The rules require TNSPs to make up the difference in each settlement period on the rare occasions that the IRSS is negative.
- For all TNSPs any net contribution that they might be required to make are pass thru costs able to be recovered from customers. This is currently the case and, thus, our proposal would not require a rule change.

4 Queue Questions

4.1 What happens to the queue order when a generator retires on a section of the network?

- If a generator retires, it will spur a reordering of the queue for generators that continue to operate in recognition that the retiring generator has freed up spare transmission capacity
- In the recalculation process, a generator's place in the queue can only improve, it cannot deteriorate
- We propose that the spare capacity freed up by the retirement or new transmission investment would be distributed to those who failed to secure a position of zero in the queue, and remaining capacity would then be offered to new entrants
- If positions in the queue are allocated through auctions, instead of holding a new auction it may be more appropriate to first offer additional capacity to parties that lost the auction but were next in line in terms of their willingness to pay for a spot
- Through this process, AEMO will work up the queue allocating new capacity to existing generators until the transmission capacity is again reached
- Generators whose capacity is still beyond the capacity of the transmission grid will then receive a sequential number in the queue in their order of incumbency.

4.2 Is the expectation that, once a queue is getting very long, this will feed into the ISP and Transmission planning?

- We believe that a long queue might signal to TNSPs that there is a high commercial interest in the area, which would lead to including upgrading the transmission line in the ISP.
- However, we do not propose any particular metric for including spurring a transmission upgrade into the ISP. Any proposed upgrades would still have to go through the RIT-T process as normal.

4.3 Queueing of dispatch likely to limit/damage contract market liquidity?

- We anticipate that our proposal would not limit or damage the contract market liquidity
- On the contrary, providing greater dispatch certainty to incumbent generators would lead to an increase in liquidity of contract markets as incumbent generators, confident that they will have access to transmission capacity, will offer more and longer-term contracts without fear that curtailment will prevent them from meeting their contractual obligations.

4.4 How are non-network / storage solutions treated?

- **Storage acting as dispatchable Energy**—Energy storage would enter the queue and dispatch on the same terms as any other generation project when serving as a generator. This is because an energy storage project entering the queue and receiving a high number means that it can only dispatch when other generators are not dispatching. This will be key to encouraging energy storage to locate in a way that eases congestion. If energy storage providers were exempt from the queue, they could attempt to discharge during congested periods which would worsen congestion rather than relieving it
- **Storage Acting as Load.** Energy storage would be treated as a load when charging. Storage providers will be allowed to sign bilateral contracts with generators that cannot dispatch due to congestion to purchase electricity at an agreed price rather than the RRP. This, in turn, would alleviate the congestion and allow generators to sell produced electricity instead of spilling it
- **Storage proving Ancillary services.** Storage providers would be exempt from the queue when providing ancillary services. The ancillary services market is separated from the energy market. For this reason, we believe it is reasonable to separate the energy and ancillary market incentives. This means that encouraging storage participation in the ancillary market should be addressed under the ancillary market regulations, not through the transmission access queue.

4.5 How will the queueing apply when there are multiple network segments on the way to a regional reference node?

- All new generation impacts the grid as a whole. The queue model uses thermal capacity at the transmission segment local to the generator connection point as a proxy for the overall impact on congestion. This is an imperfect proxy, but given the allowance for a target curtailment level, it is likely to provide sufficiently efficient location signals and hence be sufficient to address the issues which have given rise to the need for access reform.
- The access proposal is also consistent with the queue position being allocated for a number of transmission segments where that is appropriate. The model is sufficiently flexible to allow differential treatment of various transmission components to address actual and potential constraints.
- To make this assessment, a new generator that wants to connect to the transmission network would go through a regulated process (possibly by the TNSP) to determine its impact on congestion. This process would determine the material impact of a new generator on the congestion in the local area and the system’s stability overall. As a result, a proponent would receive either:
  - A zero position in the queue, if it has no material impact on the congestion, or
  - A position greater than zero, if it has a material impact on congestion in the area.

- The focus of the regulated process will be on local congestion as that is where the generator will have the largest impact; however, the TNSP will consider impact on the wider grid. This means that that if there are several segments on the way to the regional reference node, the TNSP will consider the impact on each segment.
- In addition, the TNSPs consideration of the impact on congestion on segments beyond the local connection point would bear in mind that the queuing system is not designed to provide a firm physical transmission right to the whole of the meshed transmission grid. Instead, it will provide a much firmer access right to local transmission capacity that, importantly, will not degrade over time. While congestion on the overall NEM prevents guaranteeing that a firm access right to local transmission capacity can be translated into a firm right to the NEM overall, the transmission access queue will resolve local transmission constraints.

4.6 What happens if an existing plant is refurbished (e.g. upgrade wind turbines/ inverters), after say 20 years?

- We propose that the queue position would be valid for 20 years. The duration of the queue position would not be influenced by any refurbishment during that 20-year period. The time limit to the queue position:
  - Provides sufficient certainty for generation investment because the twenty-year time period should be sufficient for generators to pay down loans and to recover their capital. It is also broadly in line with the lifespan of most VRE generators—which will make up the vast majority of new generation investment
  - Provides protection to consumers by ensuring that inefficient plants do not sit on transmission capacity years after they would have otherwise been replaced by newer, more efficient generation
- After this period, whether the plant is refurbished or not, they would need to reapply for a spot in the queue. Six months before the end of the existing plant's 20-year queue placement ends, AEMO will open up applications for the transmission capacity that the generator currently occupies. Given that they are already there, it is guaranteed that when the generator reapplies for a spot in the queue there will be at least as much capacity available as they currently occupy. If the generator has undertaken refurbishment, they will likely desire to keep their position in the queue. This can be achieved in two ways:
  - Either there will be no other interested developers and they will be granted a position of zero for an additional twenty years.
  - Or, if there are other interested generators, they will need to win an auction for the capacity. The incumbent generator is likely to be in a good position to win the auction unless they are significantly less efficient than new entrants.
- The likelihood of winning the auction unless the plant is less efficient than some new technology is likely to provide efficient incentive for refurbishment. In addition, the queue position only kicks in after the MLF weighted bid price. Thus, if a generator needs to

refurbish to remain competitive in energy market it would have a strong incentive to do so in order to be dispatched.

- This is an efficient outcome because, requiring existing plants, refurbished or not to reapply for their queue position after 20 years ensures that the most efficient generation capacity has access to the transmission network. As mentioned above, the existing generator would be well positioned to win any auction given that they already have land, civil works, and the components of the plant which are still serviceable in place. However, there is a possibility that in the intervening 20 years new technology has become available that is a dramatic enough improvement that it would be cheaper than even the refurbished existing plant and thus able to outbid the existing plant for capacity at the auction. The auction would reveal if the efficiency gains of retaining the existing plant outweigh the benefits of replacing it with newer generation.
- Note that should an existing plant lose an auction and receive a number higher than zero in the queue, they would still be able to utilize the transmission capacity during periods where there is no congestion.

4.7 Should access rights be granular (e.g. for 2-hour periods) or for the full 24-hours?

- Our preliminary conclusion is that there is no need to make the access right granular in relation to time periods since the queue position only matters during peak times. Generators that are able to operate outside the peak period would not need a queue position of 0 in order to be able to manage their curtailment risk
- In areas with a significant amount of VRE this would mean that there are likely periods in time when there is unused transmission capacity available—for example, during the nighttime in an area dominated by solar PV. Our proposal would not prevent generators from building in these areas, accepting a higher number in the queue, and only being able to transmit electricity during times when there is unused transmission capacity. We would leave it to project proponents to determine if capacity available at some time of the day is sufficient for their proposed investment to make sense.
- Thus, a new entrant is free to access transmission capacity if it believes that there is sufficient available capacity at times of the day it would like to dispatch even though it may receive a queue number higher than zero which means they will face curtailment at certain times of the day.
- Allocating queue positions on the basis of available peak capacity will achieve exactly the same result as dividing the queue into smaller time periods without introducing additional auctions. If for example, there were an auction where solar and wind developers were interested in transmission capacity, solar PV developers would likely win out for daytime capacity at auction, meanwhile wind would win out at an auction for nighttime periods. This would achieve the same result as a wind generator receiving a number greater than zero in the queue and being curtailed off during the daytime.

- If the periods of the day when there is spare transmission capacity are not sufficient to justify further generation investment, breaking down the transmission queue into distinct time periods will not change that analysis. Instead, it would introduce additional complexity and uncertainty to all potential generation projects.

4.8 Risk of a different form of disorderly bidding as gens lower in the queue may seek to bid to floor to improve likelihood of dispatch?

- While it may occur, we do not think this is likely because it would be an ineffective bidding strategy for generators with a number higher in the queue. Further, to the extent that such new generators lower in the queue are renewable generators, it will not make a difference from the standpoint of economic efficiency.
- Incumbent VRE Generators with a queue number of zero can simply bid to floor in response and be guaranteed dispatch. They would defeat thermal generators first based on the rule change and new entrant VRE based on the queue. Further, it would be a risky strategy for thermals as it raises the possibility of being dispatched when the RRP is below SRMC.
- As a result, we expect new entrant generators will bid in an orderly fashion, as they know that attempting to be dispatched through bidding the floor will not work. It is possible that this would lead all VRE bid at $-1000 all the time, instead of their SRMC of 0. However, this would not lead to economic inefficiency as all generators dispatched have an SRMC of zero.
- In practice, this will mean that whether they bid their SRMC of zero or the market floor VRE generators in a transmission node with the same MLF—which we anticipate will be the case in REZs—will be dispatched in order of their incumbency. The only point of differentiation between VRE in a transmission node—particularly in a REZ where the majority of the VRE will be located—will be the number in the queue. As a result, incumbent VRE will be dispatched first followed by more recent VRE generators. This means that while the transmission access queue will play a key role in the dispatch algorithm throughout the NEM, it will be particularly impactful in REZ areas where the ISP envisions the majority of generation investment will take place.

4.9 Would this increase the total amount of curtailed energy? Would the queue mean that generators with lower constraint equation coefficients could plausibly be curtailed first?

- We believe our transmission queue proposal will lead a significant reduction in curtailment by promoting efficient location of generators. Curtailment is ultimately the result of poor locational decisions that cause congestion that our proposal will strongly disincentivize through the queue system. However, it is possible that some curtailment of generators with lower constraint coefficients will result from the queue system.

- The risk of curtailing generators with a lower constraint equation in the operational timeframe is a reasonable price to pay to incentivize efficient location in the investment timeframe. Further, we believe that the cost in the operational timeframe will be limited because:
  - All existing generators will receive a queue number of “zero” meaning that no existing generation will be curtailed before another existing generator solely because of their constraint equation
  - The queue system will strongly incentivize efficient location for new entrants, lowering the likelihood of a binding constraint caused by new entrants and thus the need to consider constraint coefficients
  - New entrants will make locational decisions understanding that the queue system may see them dispatched after a generator with a higher constraint coefficient because of the queue system, which will prevent gamesmanship in attempting to locate where you will be dispatched based on constraint coefficients.
- Further, we would note with regards to the physical stability of the grid, the transmission queue will not provide the final dispatch order or the capacity for which each plant is dispatched—particularly in a loop. After receiving the merit order ranked by the queue, the dispatch engine must still consider the impact of each plant’s constraint coefficient whenever there is a binding constraint before ultimately dispatching each plant in the merit order to ensure grid stability.
- Our transmission access queue proposal would not interfere with this process. Instead, the queue would provide additional information to the dispatch engine when it is making its dispatch calculations on which generators should be given priority where it is physically possible. Thus, the transmission access queue would instruct the dispatch engine to curtail in the order established by the queue, recognizing that where this is not possible the dispatch engine will override the queue to maintain grid stability.

5 Transmission Charges Questions

5.1 How do you deal with the lumpiness of transmission investment? Say a new connecting party funds a transmission investment, this is likely going to benefit it, as well as other subsequent parties that connect. How do you avoid free-rider issues?

- The lumpiness of the transmission investments is an issue that the TNSP should address through the regulated process. We are only considering the TC as a safety valve in our proposal
- If a generator was considering a transmission upgrade outside the ISP's plan that it believes would provide benefits to the market, it could first go through the regulatory investment test. If the upgrade would bring benefits to the market, this amount can be rolled into a regulated asset base. This, in turn, would decrease the investment amount required from the generator.
- It is worth noting that in our proposal, generators willing to pay a full cost of the TC do not have to go through the RIT-T process. However, investments where some or all of the transmission upgrade costs is rolled into the TNSP's regulated asset base (RBA) would need to go through the regulated process
- The free-rider issue can be dealt with by requiring the subsequent generators connecting to an upgraded line to rebate some of the investment to the original proponent. Thus, they will pay for the share of transmission infrastructure from which they will benefit. In the event that the new entrant leads to congestion they would also receive a number of 1 in the queue, meaning that they would be curtailed before the original proponent when there is congestion on the local transmission network.
- In most cases, the generator would transfer the ownership of the upgraded line to the TNSP with guarantees in place for the generator that they will continue to have access to the transmission capacity. The TNSP (overseen by the AER) in turn, would decide what is a fair and reasonable rebate that the new generator should compensate to the original proponent. In essence, the free-rider problem would become a regulated process
- It is worth noting that this approach of addressing free-rider issues would work well on the radial line. However, it is hard to completely eliminate free-rider issues in the complex meshed network.

5.2 If outside the RIT-T, could this incentivize TNSPs to push transmission investment onto generators rather than pay for it themselves?

- In short, no we do not expect this to happen. TNSPs do not "push investment" onto generators. TNSPs are in the business of building transmission capacity and getting paid for it when they believe it will make economic sense.
- Note also that TNSP's must invest in order to maintain the service standards for load—that is unserved energy is less than .002%. They cannot pass this obligation to generators
- We expect the TNSP to take a realistic view of future demand. For example, if a generator requires additional capacity with significant augmentation in the area where the TNSP does not expect to see high demand for the capacity from other market participants then the TNSP has the right to charge the generator the cost of augmentation. Note that TNSPs can only invest if the project meets the RIT-T; they cannot speculatively invest.

5.3 How would the generator-funded transmission upgrades be prioritized relative to other transmission upgrades?

- We believe that the upgrades funded by generators and other transmission upgrades would not come into conflict.

5.4 What should the regulated transmission charge be based on? What is the proposed framework for regulating transmission charge prices?

- The Transmission Charge (TC) offered by TNSPs to generators would be based on the level of investment required to provide firm access to local transmission capacity without increasing congestion
- We propose that the AER would take on regulatory functions to ensure that TNSPs are offering fair TC and delivering upgrades in a reasonable timeframe. The AER must:
  - Ensure that TNSPs offer fair TC to generators. In addition, generators must have the right to appeal the TNSPs offered TC to the regulator
  - Ensure that contracts between TNSPs and generators to complete the transmission upgrade include SLAs on par with SLAs offered to the incumbent through the queuing system and the period of the agreement
  - Defining the necessary TC will require analysis of what time of day new generation investments will utilize the transmission grid to determine if they are straining the transmission grid at times they are dispatched

– Ensure that future entrants do not degrade the access right of the generator that has paid the TC.

5.5 Could the Shell Energy locational-connection fee model be incorporated into the CEIG model as the 'transmission charges as safety valve' component?

- Yes, but only as a safety valve component. This is because the Shell model is essentially proposing a Deep Transmission Charge (DTC) with full physical access rights. However, we think the physical access rights can create problems in the meshed network and threaten grid stability
- For that reason, we believe that the Shell Energy locational connection model can be integrated into our model only as part of the safety valve but not as a full physical access right.

5.6 How do you allocate firm access to a party once they have funded a new transmission line? Does a new 'queue' start?

- Generator(s) that decide to pay the Transmission Charge (TC) will be defined as incumbents and will get a zero position in the transmission queue, giving the generator the same local transmission access rights as other incumbents. There is no need for a new queue.
- It is worth noting that the queuing system is not designed to provide a firm physical transmission right to the whole of the meshed transmission grid. Instead, it will provide a much firmer access right to local transmission capacity that, importantly, will not degrade over time. While congestion on the overall NEM prevents guaranteeing that a firm access right to local transmission capacity can be translated into a firm right to the NEM overall, the transmission access queue will resolve local transmission constraints.

5.7 In addition to a higher WACC faced by generators in transmission charging, how would this approach address efficient long-term planning?

- Efficient planning of the transmission grid would still be the role of the ISP guided by the RIT-T process. As stated in our response in Section 5.3, we believe that the upgrades funded by generators and other transmission upgrades would not come into conflict. Thus, the efficient planning achieved through those processes would not be impacted.

- Transmission charges are envisioned only as a "safety valve" when a generator disagrees with the ISP and believes that there is sufficient value in a transmission upgrade outside of the ISP that they are willing to pay for it themselves. Further, before undertaking a transmission investment, generators would assess the commercial viability of the project given its higher WACC. As a result of the assessment, the generator would decide to either proceed with the project or not. Thus, we anticipate that the higher WACC for generators would not undermine the efficient long-term planning of transmission investments.
- We note that, in theory, the option to pay for transmission capacity or to invest in storage already exists; however, at present it is done on an ad-hoc, bilateral basis between the generator and the TNSP. This option is largely unworkable:
  - First, generation investors face considerable uncertainty about what transmission capacity may become available to them through planned investment and private investment in additional capacity does not eliminate the risk of being crowded out by others in the future
  - Second, commercially negotiated transmission upgrades are not regulated, and hence there is no guarantee that the pricing will be appropriate
  - Third, each such commercial arrangement requires a bespoke negotiation with TNSP.

  Thus, we propose formalizing and regulating the process by integrating the option to pay a TC into the transmission queueing framework.

5.8 WACC for transmission augmentation likely to be higher for generators?

- In general, we expect that generators' cost of capital will be higher than TSNPs' because of relative risk. However, there can be some circumstances when the actual cost of capital for generators is lower than the regulated WACC for TNSPs. For example, this could be due to:
  - The calculation of the regulated WACC making assumptions which do not reflect market reality (e.g. capital structure, use of trailing average cost of debt and so on)
  - A renewable energy generator having access to cheaper green finance that may not be available to a TNSP
  - An international parent company of the generator having access to lower cost finance given its corporate balance sheet.
- Should the situation arise where the generator has a lower WACC then the regulated WACC of the TNSP, this would not have a negative impact on efficient planning. In this instance, the generator can and probably should finance its own transmission investment to the benefit of the overall cost of the grid's transmission infrastructure.

5.9 To what extent could transmission investment rights be allocated to ensure the "right-sizing" of investments?

(e.g., could some access rights be on-sold by rights holders)

- We believe that the "right-sizing" of the transmission line upgrade would be addressed through the ability of a generator to choose to either:
  - Build a smaller transmission line that only benefits them and pay a full cost of the TC without RIT-T process, or
  - Build a larger line that would benefit other market participants may apply to have some of the cost rolled into RAB if approved through the RIT-T process and/or receive compensation from subsequent generators connecting to the line.
- Thus, generators would make a commercial assessment of the most beneficial size of the transmission line. TNSPs would also be free to make that assessment.
- If a new entrant is using spare transmission capacity, they would receive a number of zero in queue. However, places in the queue are non-transferrable and access rights cannot be on-sold. This is intended to avoid a scenario where project proponents hold up transmission capacity—thus causing subsequent projects to receive higher places in the queue—without any real intention or ability to deliver the generation project in attempt to secure spots in the queue only to sell them later.

6 Tie-break Rule Change Questions

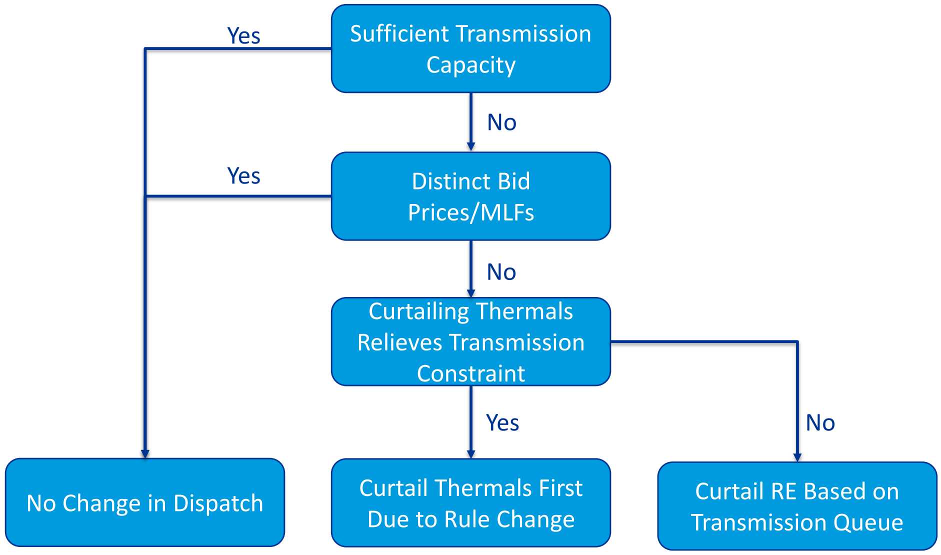
6.1 How do you reconcile the tie-breaking proposal against Snowy's proposal, which effectively does the opposite?

- Snowy Hydro's proposal aims to provide investment certainty for scheduled plant We believe this is a separate issue that is more related to the capacity incentives.

6.2 Which takes precedence for tiebreaking purposes: place in queue or SRMC?

- We do not propose to rank plants in order of their SRMC. We do propose to curtail thermal generation before RE when bid prices and MLFs are the same because thermal generators will always have a higher underlying SRMC than RE. However, bid price and MLF are considered before the thermal curtailed first rule change. Queue order is considered last. Thus, the bid price will be the first determinant of the dispatch order followed by MLF, the thermal/RE rule change, and then transmission queue.
- Thus, the queue is designed to come into effect when multiple RE generators have bid the same price (which is likely to be zero in areas where there are several VRE generators) and have the same MLF (which is likely in REZs). The dispatch algorithm will them rank them in the merit order based on their order in the transmission queue.

Figure 6.1: Transmission Queue and Rule Change Interaction



6.3 How does amending the tie breaking rule to curtail higher marginal plant first eliminate RTFB in REZs or areas with plant with similar MC?

- We assume that the acronym RTFB stands for "Race to the floor/bottom"
- In short, the rule change to curtail thermal first is not aimed at solving congestion in REZ amongst zero SRMC VRE generators. Instead, our queue proposal aims to ameliorate this issue by ensuring that incumbents' access to transmission capacity is protected from new entrants. Thus, a new entrant will not gain anything from attempting to constrain off an incumbent through race to the floor bidding.

6.4 How will curtailment of thermal plant interact with requirements for essential system services?

- Under normal circumstances, when transmission capacity is constrained, the dispatch algorithm would prioritize RE and energy storage before thermal generators when both have bid the same price. However, when grid stability requires continuous dispatch of positive SRMC generators, the system would disregard the rule. Thus, changing the dispatch rule would not interfere with the essential system services
- This is because, we understand that the security of the power system must be maintained through the dispatch process. Meaning that essential system services are also dispatched, with NEMDE co-optimizing across energy and market ancillary services to deliver

customers' needs at the lowest cost[2]. For example, the dispatch engine must consider the impact of each plant's constraint coefficient whenever there is a binding constraint before ultimately dispatching each plant in the merit order

- Our transmission access queue proposal would not interfere with this process. Instead, the queue would provide additional information to the dispatch engine when it is making its dispatch calculations on which generators should be given priority where it is physically possible
- Thus, the transmission access queue would instruct the dispatch engine to curtail in the order established by the queue, recognizing that where this is not possible the dispatch engine will override the queue to maintain grid stability.

[2] Dispatch in the NEM

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WASHINGTON, DC
1747 Pennsylvania Avenue NW, Suite 1200
Washington, DC 20006
United States of America
+1 (202) 466-6790

SYDNEY
Suite 19.01, Level 19, 227 Elizabeth Street
Sydney NSW 2000
Australia
+61 (2) 9231 6862

AUCKLAND
74D France Street, Newton South
Auckland 1010
New Zealand
+64 (4) 913 2800

WELLINGTON
Level 2, 88 The Terrace
Wellington 6011
New Zealand
+64 (4) 913 2800

PARIS
64-66 Rue des Archives
Paris 75003
France
+33 (0)1 84 60 02 00

Thinking for a better world.

enquiries@castalia-advisors.com
castalia-advisors.com