CLEAN ENERGY COUNCIL

8 November 2019

Mr John Pierce AO
Chairman
Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

Lodged via AEMC website: www.aemc.gov.au

Dear Mr Pierce,

Coordination of Generation and Transmission Investment Proposed Access Model (EPR0073) – Discussion Paper

The Clean Energy Council (CEC) is the peak body for the clean energy industry in Australia. We represent and work with hundreds of leading businesses operating in renewable energy and energy storage along with more than 6,000 solar and battery installers. We are committed to accelerating the transformation of Australia's energy system to one that is smarter and cleaner.

The CEC welcomes the opportunity to comment on the Australian Energy Market Commission's (AEMC's) discussion paper on the Coordination of Generation and Transmission Investment (COGATI) proposed access model. We appreciate that the AEMC has developed and outlined more of the detail around its proposal and thank the AEMC for the opportunity for the CEC and members to engage directly with it throughout the consultation period.

We are, however, still concerned that it is a highly complex model that has significantly moved away from addressing the key underlying problem and impetus for the COGATI access review, and that the implementation timeframe is overly ambitious and rushed. As a result, the CEC does not support the proposal in its current form and on its proposed timeframe as it does not address the pressing need for transmission investment in the National Electricity Market (NEM), may increase costs to generators and therefore consumers, and could deter future generation investment at a time when this investment is critical to maintain reliability and put downwards pressure on prices as a number of coal-fired generators close.

Any decision to progress the reform would need to be supported by robust quantitative analysis that demonstrates a net market benefit given the potentially significant direct and indirect costs associated with such a fundamental market change. The model should also be fully formed and tested before a rule change commences. Given this process should not be

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rushed, it would be more sensible to align the timing of the development and potential implementation of this reform with the Energy Security Board's (ESB's) post-2025 design work.

The remainder of the CEC's submission expands on these concerns. We also provide preliminary feedback on the proposed access model, noting we have had limited opportunity to engage deeply in the detail given the short timeframe to provide a submission.

If you would like to discuss any of the issues raised in this submission, please contact me, as outlined below.

Yours sincerely,

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The need for change

A key development in the discussion paper compared with earlier versions of the proposed access model is the removal of the third pillar relating to transmission planning and investment. By doing so, the AEMC proposes that this will continue to be conducted using the current regulated process, including the Integrated System Plan (ISP), and instead the introduction of financial transmission rights (FTRs) will indirectly influence transmission planning and investment decisions over time.

This approach may be pragmatic given the difficulties associated with developing a model where transmission hedges could directly influence and fund transmission build and the lack of international precedents for this. However, it has significantly moved away from the overarching objective of the COGATI access review to better coordinate generation and transmission investment. Throughout this review process, the clean energy industry has maintained that congestion is a real concern for generators and that building more transmission capacity is what is required to address this problem in order that more low-cost generation can be built to replace exiting coal-fired generators. We have also maintained that the ISP outlines a pathway for future transmission network development and therefore effectively actioning the ISP would go some way to addressing this problem. Improvements to the existing Regulated Investment Test for Transmission (RIT-T) around the current requirement that new generation be sufficiently committed for the corresponding market benefits created by the associated transmission investment to be considered would also assist with ensuring efficient delivery of strategic transmission projects.

We are now looking at a very complex access model that is not looking to address the pressing need for increased transmission capacity. Instead, the proposal to introduce dynamic regional pricing and FTRs is focused on second-order objectives such as delivering more efficient dispatch, better incentives to operate generation and storage assets efficiently and better year-to-year cashflow management for transmission network service providers (TNSPs). The CEC has serious concerns that this change of focus and the subsequent perceived potential benefits do not outweigh the substantial costs associated with revolutionising the access and operation of the NEM. From a generator's perspective, the complexity of the model may not produce a net benefit as they will need to operate in a more complex environment that requires new modelling and trading skills that they do not currently have. Managing this complex environment is ultimately not a costless exercise. Such deleterious impacts to generators will ultimately flow on to consumers.

In the market today, the potential for significant reform from this COGATI review is already impacting new generation investment. Generators are already experiencing difficulties in securing offtake agreements and investors for projects. The COGATI review is also already impacting financing negotiations and will continue to do so if a decision to go ahead with the reform is confirmed. Existing financing contracts are likely to require renegotiation to accommodate the changed arrangements and there is a high possibility that generators will have to accept less favourable terms than currently. The new arrangements will also need to be accounted for in any new financing contracts. There is a potential for higher risk premiums where FTRs have not been secured or that financiers with limited understanding of the framework may even decline financing on the basis that a generator has not secured FTRs. The outcome of this is that either new generation will not be built or there will be a higher cost of capital associated with the new generation. Neither outcome is in the long-term interest of consumers.

The CEC welcomes the AEMC's greater focus on quantitative modelling to support the proposal. Stakeholders have been requesting quantitative analysis in relation to costs and benefits as well as to support design development since the AEMC's first consultation paper in March 2019. This analysis should be accompanied by a comprehensive assessment of the complexities inherent in the proposed access model and a more detailed explanation of how the proposed model might operate in practice. The clean energy industry is willing to engage with the AEMC throughout this analytical exercise and further model development to see whether our concerns are in fact misguided.

Implementation timing

The above discussion ultimately links to the timing to develop and implement the proposed access model. The CEC is very concerned that the model development has been rushed, leaving significant detail to be developed through the rule change process next year. This exacerbates the potential for unintended consequences as a result of implementing a model that has not been well tested. Until the above analytical exercise is completed, we cannot support the proposed access model in its current form. We do not support rule changes being progressed next year as it is sub-optimal to undertake modelling and detailed design development through a rule change process. Industry needs to have comfort that a fully formed model has been developed and tested before it is endorsed by the COAG Energy Council and a rule change process commences.

The CEC believes the July 2022 implementation date is unachievable. This not only relates to allowing sufficient time to fully develop and test the model, but there are substantial system, process and procedure changes associated with such a significant market reform, as well as a need for in-depth industry education on the changes. Even if a rule change was finalised in 2020, this would allow only 18 months for the necessary changes to be made. As a minimum, the Australian Energy Market Operator (AEMO) would need to develop the auction and make changes to its dispatch engine. It is unclear whether this could be done in this short timeframe. For example, at the public forum in relation to the proposed rule change on transmission loss factors, AEMO gave initial feedback that implementing dynamic loss factors would be a "multi-year" process.

The 2022 implementation date is also overly ambitious for generators to understand and integrate the changes. Notably, these reforms would trigger change of law and/or market disruption clauses in current power purchase agreements (PPAs) given these contracts typically refer to Regional Reference Price (RRP) and Marginal Loss Factors (MLFs), which are terms that are expected to change with these reforms. In addition, it is unclear what this implementation timeframe would mean for existing settlement residue auctions (which are to be replaced in the proposed access model) and existing ASX wholesale contract market products (which are an integral part of the portfolio strategies of all market participants and also reference the RRP) given these are already being sold for late 2022.

The CEC is concerned that this ambitious implementation timeframe may lead to a generation investment freeze. Investors may hold back investments in order to better understand how the new framework works, observe the pricing outcomes of auctions and ensure there are no unintended consequences from a rushed implementation. An investment freeze is a deeply worrying outcome at a time when significant amounts of new generation investment are required.

Given the strong case for further model development, more rigorous analytics and a revised implementation date, the CEC suggests a more sensible approach would be to align the timing of this reform with the ESB's post-2025 design work. In the meantime, there are number of other pressing reforms that would result in immediate improvements necessary to facilitate the energy transition. These include:

- Progress should continue to effectively action the ISP. These include advancing the governance framework and the system-wide planning model rule change proposals and the two proposed funds to underwrite expenditures for Group 1 projects that are time critical[1] and extend transmission assets to connect to Renewable Energy Zones.
- The AEMC should make a determination in relation to the transmission loss factors rule change proposal to move to an Average Loss Factor methodology as quickly as possible as an interim solution to assist industry with the current volatility in MLFs while a longer-term solution to MLFs is explored.
- The AEMC should revisit the current system strength requirements. Under the current 'do no harm' requirement, connecting generators are increasingly being required to build synchronous condensers for the purposes of system strength remediation. This is resulting in multiple synchronous condensers being built by multiple connecting generators, which in turn is leading to a degree of overbuild. This is not an efficient market outcome.
- The market bodies and industry should work together to address current grid connection problems. The current grid connection process is leading to increased costs and delays for new developments. There are potential improvements to this process, particularly around transparency and application process consistency, technical capability and modelling certainty, and injecting balance into the negotiation framework.

Proposed access model detail

While the AEMC has presented what appears to be a mathematically, internally consistent model on face value, the CEC has concerns regarding the level of detail provided in the discussion paper. There are clearly many critical, significant details to be developed and expanded that would enable stakeholders to better understand the practical implications of the proposed access model and provide a thoroughly considered response on the model. We have endeavoured to engage with the detail presented. However, given the short consultation period and lack of granular detail provided, this has not been an easy task. As a result, this section outlines our initial comments and concerns relating to the detail presented.

[1] Noting an announcement was made on 28 October 2019 that the Federal and NSW Governments would provide $102 million to underwrite the upgrade to the Queensland-NSW interconnector.

FTR design does not support investment certainty

The CEC does not consider the FTR design features would support the business case for new investment. A key concern around the current proposed model is that the FTRs essentially offer only a short-term, non-fully firm hedge. In addition, developers should be able to purchase FTRs well in advance of their plants becoming operational.

1. *Time horizon*

The discussion paper explains how large-scale generators and storage would be able to purchase rights for quarterly periods, up to three to four years in advance. This horizon does not make the FTRs bankable for new renewable investments, which have a far longer life of 20 or more years, nor aligns with PPA terms. It also does not sufficiently address the current problem whereby a new generator can easily connect directly next to an existing generator, thus reducing the existing generator's level of access and impacting their MLF. We consider that a ten-year lead time would better support the investment case through better aligning with PPA terms and facilitating access to both debt and equity financing. It would also allow a generator to purchase FTRs over a longer period to insure against poor locational decisions by subsequent generators. The CEC appreciates that a longer lead time may have implications for new generator entry. This would need to be evaluated. It may be that the process of auctioning FTRs in tranches may mitigate this. We also appreciate that a longer lead time implies more speculative forecasting, particularly in relation to transmission capacity and the number of FTRs. This should be further investigated with the aim to balance the needs of generation developers and investors against the ability to forecast future transmission constraints with an acceptable degree of accuracy.

2. *Firmness*

Compounding this concern is that the FTR is not fully firm given if the fund that arises from excess settlement residue is exhausted, FTR payouts would be scaled to the extent necessary. The CEC strongly believes that the FTRs must be fully firm if they are to be an effective hedge product for generators. The AEMC has indicated it believes there should always be sufficient residues to cover the hedges, but we remain unconvinced that this is the case. It is conceivable that non-thermal constraints (e.g. system strength) and dynamic loss factor volatility could quickly destroy FTR firmness as regularly paying out for these would quickly draw down the fund.

This problem of non-fully firm hedges would arise throughout the network. The most expensive hedges are likely to be for the most constrained parts of the network. These parts of the network are likely to see the biggest price differentials arise between the local price and the regional price and more frequent occasions of this occurring. As a result, there will be more regular drawdowns on the fund to the point that the FTRs are no longer fully firm. It is a perverse outcome that the most expensive FTRs in the areas where they are needed the most are not fully firm.

Given the single pooled fund across the NEM, this would have flow-on effects to lightly constrained parts of the network. Should a constraint arise in these areas, given the FTR payouts for very constrained parts of the network have exhausted the fund, these would also need to scaled back. It is possible that these areas may never be fully firm depending on the frequency of constraints in this part as well as other parts of the network.

It is integral that modelling is done on the sufficiency of the settlement residues to back FTRs. The CEC appreciates that this this modelling has already been noted by the AEMC in the discussion paper. The modelling should consider a whole of NEM approach and then deep dive into examples focused on the 'worst' parts of the network to better understand whether significant non-thermal constraints and dynamic loss factor volatility do in fact quickly destroy FTR firmness.

The CEC strongly encourages the AEMC to consider how to ensure FTRs can be made fully firm. While the AEMC proposes that the proceeds from the FTR auctions be used to offset transmission use of system (TUOS) charges, we counteract that a non-fully firm FTR would flow through to increased cost of capital for generators and therefore higher electricity prices for consumers. The position on auction revenue should be reconsidered. There may be a more balanced approach whereby auction revenue is rolled into the fund to provide firmness to the FTRs and then can be rolled out to offset TUOS at a later date if it is clear that firmness is assured. This could happen on a continuous rolling basis to provide firmness to the FTRs while still allowing some offset of TUOS. Another potential option is to scale up the volume weighted average price (VWAP) rather than scale down the FTRs. Given the VWAP approach would theoretically result in lower prices than under the current RRP approach, even with some scaling up of the VWAP this would still result in a lower price than under the current RRP, leading to a benefit to consumers.

3. *Purchasing FTRs during connection and commissioning*

The AEMC proposes that only physical market participants would be able to acquire FTRs between a local price and a regional price through the auction process. While we understand through conversations with the AEMC that it is its intent, the discussion paper is not explicit in that intending participants will also be able to purchase FTRs through the auction process. To support investment decision making, intending participants (that intend to be scheduled or semi-scheduled generators or scheduled only) must be able to purchase FTRs during the connection and commissioning phases rather than only once the generator is physically participating in the market. There are, however, a number of complexities around this that would need to be worked through.

Firstly, the physical capacity of new developments is subject to change throughout the connection and construction process. The ability to establish the physical capacity at which the amount of FTRs that could be purchased is capped would thus be difficult at this stage.

Secondly, allowing intending participants to purchase FTRs could result in situations whereby intending participants bid aggressively to secure FTRs and then sit on them without progressing their development. There could even be the extreme situation where players become intending participants with no intention of constructing a generator for the sole purpose of purchasing FTRs to block out competitors or profit from selling them at a higher price later. These situations should obviously be avoided. This lends itself to some sort of use it or lose it framework although we suggest preventing this behaviour is preferable to dealing with its aftermath.

Finally, thought should be given to extending the ability to purchase FTRs to deemed to be registered participants. Developers who intend to sell their projects and therefore do not meet the requirements to be an intending participant should be able to purchase FTRs and sell their project and associated FTRs as a package. Not being able to purchase FTRs and sell a project and FTRs package could reduce the willingness of another party to buy the project.

4. *Pay out*

The discussion paper outlines how FTRs could be purchased through the auction for either continuous payouts (i.e. the right would pay out whenever there is price separation) or within a specific time of use band (i.e. only pay out at pre-defined times of the day or night). The CEC appreciates the consideration of time of use products to acknowledge such products may be particularly useful for some forms of variable renewable generators. The AEMC should consider more granular products, such as four-hour products, as they may align better with the generation profiles of solar generators that are active only during daylight hours and wind generators that can have more sporadic profiles throughout the day and night. We note, however, that more products may risk liquidity for FTRs, particularly in the secondary market.

FTR auction

The AEMC intends that FTRs would be sold through a series of simultaneous feasibility auctions of the network run by AEMO, with input from TNSPs to set the parameters of how many FTRs could be sold. While the CEC appreciates the simplified examples given in the discussion paper of how the simultaneous feasibility method could work, this is an inherently complex method given the complexity of the power system. Coupled with this complex method are the multitude of decisions that need to be made to participate in the auction around not just the amount and price to bid, but also to which regional price, continuous payout versus time of use and linked bid strategies. The clean energy industry is concerned that this is creating a very complicated decision-making environment that will require auction participants to employ costly modelling and consultants and undertake substantial internal upskilling to effectively manage, which will need to be factored into their levelised cost of energy and therefore prices that would emerge in the wholesale market. This will particularly impact newer and smaller renewable developers who do not typically have this form of trading expertise in-house.

1. *Price*

Price is the big unknown in the auction process and is likely to be the most difficult element for participants to calculate. The clean energy industry is apprehensive about the pricing that may emerge through the auction. There are a number of drivers of FTR auction outcomes, such as expected congestion, contract positions, technology type, outages and number of participants. The potential for a mismatch to emerge between price and value is a concern given values may differ for different technology types. For example, it may be possible that particular generators are likely to have a higher incentive to bid for FTRs (i.e. coal generators that have a positive short run marginal cost may have more to lose if they do not obtain FTRs). Also, it is highly probable that obtaining some amount of FTRs will become a requirement for getting finance for a project. When multiple parties have to obtain FTRs irrespective of price, this is likely to result in very high and potentially very volatile prices.

2. *Quantity of FTRs sold*

The discussion paper explains that determining the quantity of FTRs to be sold will be done with regard to the existing and committed physical capacity of the system with some level of capacity held back to account for such things as network outages. This appears a reasonable approach to improve FTR firmness but the extent to which this conservatism is applied is unclear and potentially problematic, especially given the more conservatively the quantity of FTRs is determined, the fewer the number of FTRs that are made available to generators. A balance must be struck but the CEC is unclear on how this can be done effectively. It may be appropriate that an independent expert panel or the Australian Energy Regulator (AER) oversee and verify the process to determine the quantity of FTRs to be sold.

3. *Auction proceeds*

The proceeds from the auction are intended to be distributed to TNSPs to offset TUOS. The CEC has already commented on this above but in addition, the discussion paper is unclear on how this will occur. This is particularly relevant where an FTR is purchased to a regional price that is different from the generator's location. For example, if a generator is located in New South Wales (NSW) and buys an FTR to the regional price in South Australia (SA) there would need to be a methodology to split the proceeds between the TNSPs in NSW and SA.

4. *Australian Financial Services Licence*

Given an FTR is effectively an option, participants in the auction may be considered to be dealing in financial products. This would require an Australian Financial Services Licence (AFSL). Legal advice is needed to establish whether an AFSL would be required for FTR holders, both to participate in the auction and the secondary market. The majority of renewable energy developers do not have an AFSL. Obtaining such a licence requires time and is not without cost.

5. *Transferability of FTRs*

The AEMC needs to consider whether limitations are necessary on the ability to transfer FTRs. Some mechanism is probably needed to prevent FTRs being transferred within a company or amongst related bodies corporate to avoid a situation where FTRs are purchased in an area with lower constraints and therefore lower prices and moved to be used in more constrained areas. This issue ultimately goes to whether the FTR is assigned to a particular generator or to the generator owner. The former seems more fitting.

Dynamic loss factors

Presently, the current year-on-year volatility in MLFs is proving challenging for existing generators and investors and developers of new generation. For existing generators, MLFs directly impact revenue and therefore significant adjustments materially influence their financial sustainability, which in turn is currently leading to refinancing requirements and financial distress and could lead to future default and supply disruption. For prospective generators, MLF volatility is expected to increase the risk premium for new investments, increasing the levelised cost of energy and potentially deterring new investment in new generation.

The discussion paper proposes moving to a dynamic loss factor framework. The CEC is concerned that this would potentially increase the volatility of loss factors. While FTRs are intended as a product to hedge loss factors, it is hard to see how they can provide a perfect hedge for highly volatile dynamic loss factors because as explained above, FTRs will likely be non-firm as volatile losses will quickly draw down the settlement residue fund.

It is the AEMC's intent that losses will be incorporated into the local marginal price and regional price, but it is not clear in the discussion paper how this will be done and therefore how hedging for losses will practically work. There is no international precedent on which to draw an understanding of hedging for dynamic loss factors to assist industry to better understand this element of the proposed model. In addition, current MLFs are already difficult to model. Modelling dynamic loss factors will be even more so, making it difficult for generators to establish the level of FTRs needed to hedge these losses. The complexity in modelling dynamic loss factors will also complicate the business case for new investments, thereby increasing uncertainty, investment risk and the risk premium for new investments.

Finally, given that MLF volatility is one of the issues this reform purportedly seeks to resolve, it is hard to see how this will be achieved by swapping volatile MLFs for volatile FTRs.

Competition concerns and gaming potential

The AEMC does not envisage that market power will be increased as a result of the introduction of dynamic regional pricing. In making this statement, it focuses on bidding behaviour and the ability of participants to manipulate the wholesale market price above their long-run willingness to pay or sell electricity. The CEC would like to see modelling analysis to confirm this position.

We are concerned that this focus on market power in the wholesale market has failed to recognise the opportunity for market power and gaming in the FTR market. We have already described the potential for intending participants to purchase FTRs to put a squeeze on the FTR market with no real intention of using them in order dissuade other investments or drive up the FTR price so as to sell them later at a higher price. The possibility for 'transmission sitters' could also arise in relation to existing generators. A well-funded player could drive out competition by bidding up the costs of their competitors' FTRs. Likewise, a player in an unconstrained part of the network could purchase FTRs with no real need for them solely to ensure new entrants in that part of the network and competitors in other more constrained parts of the network cannot purchase them. The AEMC should undertake further analysis into the potential for transmission sitting behaviour and consider mechanisms to prevent it.

Transitional arrangements

The discussion paper acknowledges that transitional processes would apply in the early years following implementation of the proposed model and outlines proposed principles and an approach for grandfathering access. The paper, however, does not provide the important 'line in the sand' details as to who, what, how much and for how long grandfathering will apply. Transitional arrangements are likely to be one of the most complicated and hotly debated elements of the proposed model. The AEMC is well aware that industry is keen for confirmation of the detail around the level, length and profile of grandfathered rights. To assist the AEMC in developing this detail, the CEC wishes to comment on several important matters related to transitional arrangements that require deeper consideration and clarification.

The AEMC suggests that existing generators would receive an amount of transitional FTRs for free. The CEC cautions that this approach does not recognise the pipeline of developers that have made and will continue to make investment decisions based on the current access framework. As such, developments that have reached financial close prior to some clear cut-off date should also receive transitional FTRs. This cut-off date should be set at some point in the future to give investors and developers of early-stage prospective projects sufficient time to financially close these projects.

Transitional arrangements should also be clear on the transmission capacity for which transitional FTRs would be available. There are a number of RIT-Ts underway for new transmission capacity that if approved, would be operational in the coming years. Depending on the final implementation date of the access model, the AEMC would need to be clear on whether this capacity will be grandfathered. This is particularly relevant for generation projects under development that may make investment decisions based on the committed new transmission capacity. For example, the AER is expected to make a determination on the RIT-T for ElectraNet's Project EnergyConnect by the end of 2019. If approved, construction will be completed on the new interconnector progressively through 2022 to 2023. There may be new generators that make investment decisions based on this new interconnector and will align their operational start with the operational start of the interconnector. There is a strong case that these types of projects and therefore all existing generators should receive transitional FTRs for approved new transmission that is committed but not yet operational at the implementation of the new access model.

The CEC understands that the intent behind grandfathering is that transitional FTRs should approximate the implicit access that generators currently enjoy. That is, they should be no worse off than under current arrangements. We caution that the arrangements should also ensure that existing generators are made no better off than under current arrangements as this could dissuade new generation entry.

This principle is particularly relevant when considering how current MLFs will be factored in to establishing a generator's current level of access. The current MLF approach is already complex and problematic, which in turn means establishing transitional FTRs on the basis of current MLFs will also be complex and problematic. Further complicating this is the fact that projects that have reached financial close and should receive transitional FTRs will not have an MLF and whatever MLF they are assigned will impact the MLFs of existing generators. The easiest option would be to grandfather all generators at an MLF of one. However, given most generators have an MLF of less than one and there are already indications that MLFs will continue to fall over coming years, this clearly affords an implicit level of access that is better than their current level of access. Similarly, generators that have an MLF of greater than one would be made worse off if they were grandfathered an MLF of one. This requires careful consideration.

The discussion paper is unclear on whether generators would be able to buy and sell transitional FTRs. The commentary around a one-off auction suggests they would be able to do so but the CEC believes further thinking is required around this. The AEMC should consider whether it is appropriate that generators can gain proceeds from selling transitional

FTRs through an auction or in the secondary market. They would essentially be able to sell something which they received for free, which suggests they could be made better off than under current arrangements.

The AEMC intends that FTRs would be available that relate to the difference between a nominated local price and any regional price. The CEC questions how this arrangement will be applied to transitional FTRs. A current generator may have a PPA with a load in a different state to the one in which it is located. For example, a generator in south-west NSW may have a PPA for delivery in Adelaide. This generator would then likely want transitional FTRs for the SA regional price. It would be easy to assume that all generators should be grandfathered to the regional price of the region in which they are located but this is limiting them to a subset of FTRs that would be available. In this example, being automatically assigned transitional FTRs to the NSW regional price and not to the SA regional price would represent a worse level of access for the generator than it currently has. Given PPA information is confidential, it is unclear how this issue could be overcome to ensure generators are provided transitional inter-regional FTRs commensurate with their current implicit level of access.

Over coming years, a number of thermal generators are expected to exit the market. It is likely that there will be closures during the transitional period. The CEC believes transitional FTRs should be surrendered should a generator close. To facilitate competition and new entry, the generator owner should not be able to continue to hold these transitional FTRs and they should be made available to the market, even if the generator is intending to build a new plant at the same location or elsewhere in the system. Given the three years notice of closure requirement, the rights for any period post the closure date should be made available at the point when the generator makes its three years notice.