2019 COGATI IMPLEMENTATION

Response to AEMC Coordination of Generation and Transmission Infrastructure Discussion Papers

November 2019

Summary

Stanwell welcomes the opportunity to comment on the Coordination of Generation and Transmission Investment (COGATI) Discussion Papers on the proposed access model and Renewable Energy Zones (REZs).

Proposed Access Reform

The objective of reform

The proposed COGATI reform centres around the proposition that improved coordination between centrally planned transmission investments and distributed decision making relating to generation investment would improve market function and ultimately lower total system costs. In both this Discussion Paper and the previous COGATI Directions Paper, the identified issues that necessitate the proposed access reform included transmission network congestion, decreasing marginal loss factors, generator revenue uncertainty, lack of locational price signals and adverse operational incentives for generators and storage such as disorderly bidding.

Unfortunately, the Discussion Paper presents a market redesign which is no longer about the coordination of generation and transmission investment but rather a disproportionate approach to achieving incremental gains in dispatch efficiency.

As such, the proposed model will, despite good intentions, compete with the ESB's post 2025 market reform process. It will require a fundamental change to investment and operational decision making with the aim of ensuring adequate and efficient investment in assets to support only the provision of bulk energy. As an assumed input to the ESB process it would likely restrict the ESB from considering more holistic market designs.

In its submission to the Directions Paper, Stanwell expressed concern that the proposed framework would only partially address the issues identified as requiring the reform, if at all. The updated access model proposed by the Commission fails to alleviate these concerns, for example:

- The access reform presented will not address congestion, especially in the short-term, as the explicit link between Financial Transmission Rights (FTRs) and transmission planning has been removed.

- Loss factors represent the physical impact of locating plant distant from load or near other generators. The proposed design of FTRs does not reflect this physics other than in aspirational terms.
- The proposed design does not appear to significantly change or deter the impact of investments that impair transmission adequacy on nearby projects and incumbents.
- FTRs will not address race-to-the-floor bidding when the network is congested and generators behind the constraint remain contractually incentivised to maximise volume.

Access reform is complex, and given the issues identified by stakeholders seem likely to far exceed any anticipated benefits, the Commission should not progress this reform. Rather, there are a number of no-regrets actions that the Commission can pursue that will help to address the issues the market is currently facing while creating less disruption. These are discussed on page 5.

Process of the proposed reform

The development and consultation of the access reform has been protracted and inconsistent, spanning over at least the decade since the *Review of Energy Market Frameworks in light of Climate Change Policies*. While Stanwell acknowledges the efforts of the Commission in engaging stakeholders and leading the thought development in this space, the proposed model for access reform is neither complete nor comprehensive. It should not be implemented in its current state as it fails to address industry's concerns of its integration into the broader reform landscape:

- **Incomplete and insufficient detail -** Fundamental aspects of the design have been deferred by the Commission to future iterations. These include the treatment of loss factors and grandfathering provisions. Stakeholders cannot provide substantive feedback on the reform package as a whole unless key details are presented.
- **Aspirational benefits and unidentified risks –** Because the design is incomplete and evolving significantly between publications there are a number of risks which have not been identified and therefore not considered in evaluating whether the proposed change is beneficial. These are discussed in detail in the appendix to this submission. In addition, the Discussion Paper contains a number of proposed benefits which can only be described as aspirational given the lack of detail as to how they would be delivered.
- **Integration with broader market reform –** There are a number of other significant rule changes and reviews in process that will interact with COGATI, most notably the Energy Security Board's (ESB's) post 2025 market design, wholesale demand response and transmission loss factors.

  Stanwell is cognisant of the Commission's interaction with the ESB, and the Discussion Paper notes "the ESB's paper suggests any recommendations the ESB's post 2025 project makes will be consistent with the COGATI review proposals"[1]. This is not sufficient to give market participants confidence that the two processes will result in efficient and effective outcomes. The disparate processes deny industry the opportunity to consult on the reform package as a whole, limiting consideration to components in a piecemeal fashion.
- **Integration with recent rule changes** - The proposal to auction FTRs only three to four years in advance creates a number of challenges and appears to undermine the proposed benefits of the reform. Generators needing to make closure decisions on marginally economic plant must give the market at least 42 months notice but will not have been able to determine whether they will be able to secure FTRs and at what price in order to sell hedges that could underpin the continued operation of the plant.

  Under the Retailer Reliability Obligation (RRO), some generators may have a Market Liquidity Obligation (MLO) placed on them commencing three years ahead when limited or no FTRs have been made available. This exposes these generators to both the risk that they are unable to secure sufficient FTRs to facilitate the hedges sold as an MLO and the risk that the cost of FTRs make the hedges sold uneconomic.
- **Priority and Proportionality –** Given transmission planning is no longer a tenet of the access reform, the overarching objectives of the proposed design are limited to increasing dispatch efficiency. Against the backdrop of major work already in progress, Stanwell questions

[1] COGATI Proposed Access Model Discussion Paper, page viii

the relative priority of the reform compared with the emerging system security and reliability challenges. The proposed reform does not appear to consider emerging issues such as the provision of inertia, system strength, improved frequency control etc., which are likely to need to be integrated with the market design for the delivery of bulk energy and peak capacity.

Furthermore, it is not clear that the proposed changes will deliver benefits which exceed the cost of such disruptive changes.

- **Implementation timeframe –** Despite the material changes in the proposed access reform since the previous iteration, the unrealistic schedule for implementation has not been altered with the access model anticipated to commence 1 July 2022.

  This tight timeframe will not only limit consultation and consideration of the proposed market design changes, but risks significant cost and disruption to the industry as its implementation necessarily would overlap other significant changes, as illustrated in Figure 1.

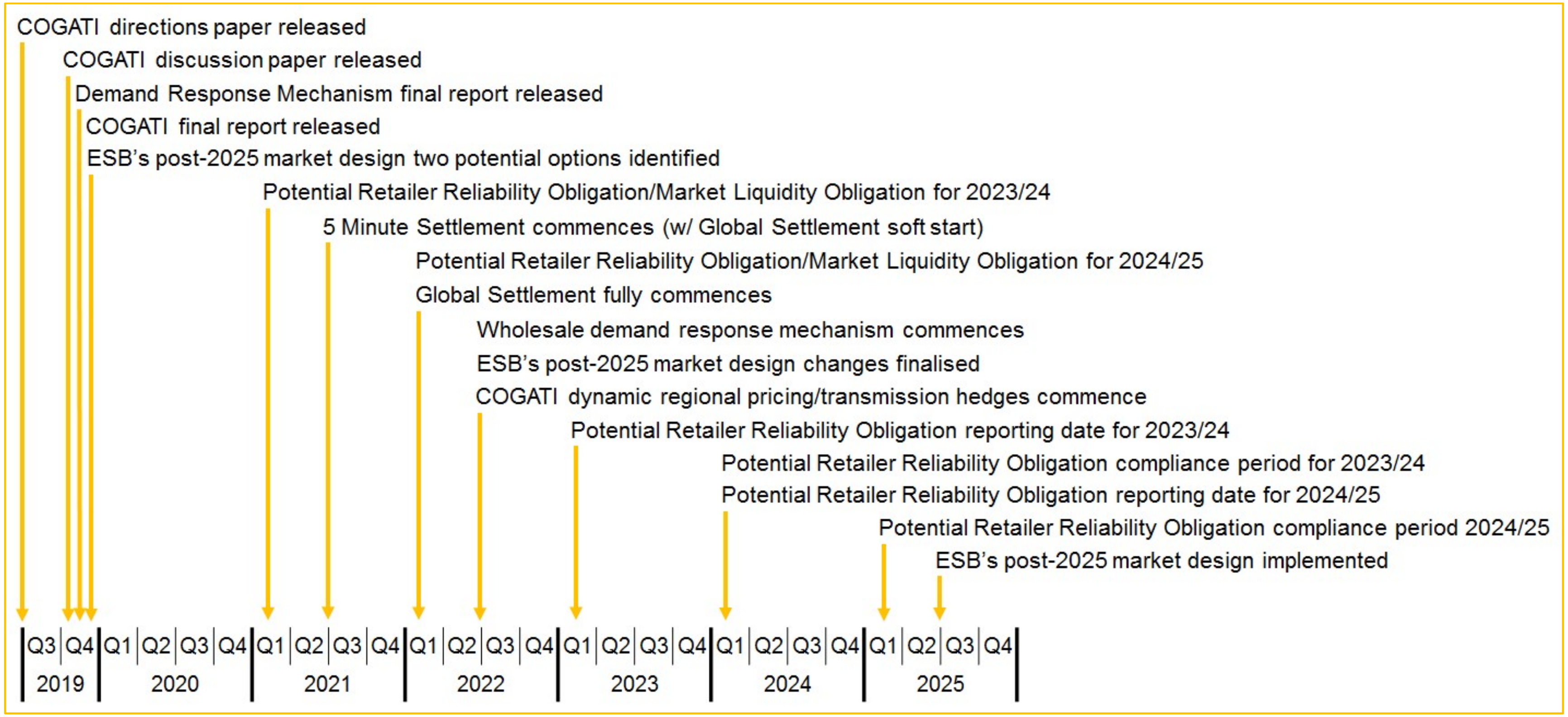


Figure 1: Timeline of current market design changes

While Stanwell opposes the overall proposal in the Discussion Paper, there are some aspects which the Commission could instead seek to implement immediately[2] to generate benefits while minimising disruption to industry.

Opportunities to implement no-regret changes

- **Redevelopment of NEMDE -** The Commission acknowledged that a key pre-condition for implementing the proposed access model is the redevelopment of the National Electricity Market Dispatch Engine (NEMDE) which currently assumes all load is at the regional node rather than locational.

  The redevelopment of NEMDE is likely to be a no-regrets activity as, regardless of whether access reform occurs, a more accurate model leads to less model-induced inefficiency. A more granular model is also likely to be required for the SA-NSW interconnector proposal.

- **Locational congestion signals –** As the Commission highlighted, NEMDE already produces information about local congestion from which a locational price could be derived. This local congestion information could and should be published, providing an immediate signal to potential projects.

  Alternatively, this information could be published once the upgraded NEMDE were introduced, preferably including historical information.

- **Alternative approach to loss factors -** The Commission could investigate or pursue alternative methodologies for estimating and applying loss factors through the current transmission loss factor rule change. Stanwell expects the required information to be the same and recommends consideration of AEMO's previous work in this area[3].

Renewable Energy Zones

Stanwell agrees that REZs should be considered separate to access reform of the meshed system, although the potential interaction of the two still needs to be addressed.

The concept proposed for Type B REZs works for radially-connected areas where individual assets are relatively identifiable. However, in meshed areas of the network (either at the time the REZ was established, or subsequently as additional transmission lines are built), the value of the FTRs over the component of the shared network the REZ contributed to may be substantially lower.

Stanwell is concerned that the proposed REZ model may limit future network development if these zones cannot be meshed without devaluing REZ participants' access rights.

Detailed feedback on proposed access model

In the following appendix, Stanwell details feedback on the proposed access model, including impacts on the market that do not appear to have been considered:

- The change from Regional Reference Price (RRP) to Volume-Weighted Average Price (VWAP) would likely create a price disruption event for financial contracts and reduce the effectiveness of hedges under accounting standards.
- The introduction of dynamic loss factors would require a change in bidding rules, as generators would not know their loss factor when submitting day-ahead bids;
- Shifting cost recovery from transmission charges to generator long-run costs is likely to compound the required return on investment; and
- The impact on contract market liquidity is likely to be more complex than the optimistic views provided in the discussion paper.

Stanwell welcomes the opportunity to further discuss this submission. Please contact Evan Jones on (07) 3228 4536 or at evan.jones@stanwell.com.

[2] Note that Stanwell considers that any new proposals should have a timeline that does not interfere with in-flight reforms underway such as 5 minute settlement and global settlement.

[3] https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Loss_Factors_and_Regional_Boundaries/2018/MLF-Information-Session---Slides.pdf

Appendix: Feedback on proposed access model

Transmission investment

Unclear how auction results will inform transmission investment

It is not clear how the proposed reform would improve the coordination of transmission and generation outside of radially-connected Renewable Energy Zones (REZs).

If a new entrant proposes connecting to a part of the network with limited transmission (or at least high competition for contracted transmission access) it should increase the price of access rights but that price increase may or may not result in local investment by the NSP.

While the Discussion Paper only describes the use of the auction prices in transmission planning as "indirect"[4] the REZ paper indicates that "the receipt of such payment or bid would not drive the RIT-R evaluation"[5]. As the RIT-T already contains a "market benefits" calculation (typically based on generator fuel cost and capital expenditure) inclusion of the auction results may lead to double counting.

Unclear how using FTR revenue to reduce TUOS will signal NSPs to build to reduce congestion

The proposal is to retain existing planning processes for transmission (allowing for the actionable Integrated System Plan (ISP) process being undertaken in parallel) and overhaul energy market price formulation and settlement processes with those changes providing indirect feedback to the transmission planning process.

However it is unclear what actionable information would be produced. The proposal to only auction a subset of existing and committed transmission capacity to physical participants does not appear to allow for information on the preferred generation investment to emerge.

[4] AEMC, *COGATI proposed access model discussion paper*, 14 October 2019, page 13
[5] AEMC, *REZ discussion paper*, 14 October 2019, page 34

Unclear how STIPS will create significant incentive

The Discussion Paper states that the Commission expects "that the 'strength' (i.e. the revenue at risk) of the [Service Target Performance Incentive Scheme] would be the same" under an enhanced TNSP incentive scheme"[6]. It is not clear how a new incentive scheme with the same revenue at risk would improve incentives, particularly if the AEMO-run residue account balance is affected by events in other regions.

To the extent that STIPS does create an incentive, it is to release less units for auction.

Under FTRs, generators pay NSPs to provide access to the network. NSPs also face the Service Target Performance Incentive Scheme (STPIS), which incentivises NSPs to manage the physical capacity of the network with relatively small financial rewards and penalties.

The Commission acknowledges the balance that will have to be struck between providing sufficient FTRs for participant risk management purposes and ensuring reasonable firmness of FTRs sold.

Stanwell is concerned that NSPs will tend towards limiting the volume of FTRs made available relative to the capacity of the network (either under normal operating conditions or when the network is constrained).

The costs of under-provision are borne by all generators (and by extension, consumers);

- those who are unable to purchase FTRs are exposed to the LMP when additional FTRs could have been made available; and
- those who are do purchase FTRs do so at a price higher than the market clearing price had a higher volume of FTRs been available.

Reduced TUOS does not mean reduced total transmission cost

The proposed access reform will not reduce the total transmission costs to consumers; it will transfer how these costs are recouped (with the potential for additional margins to be added to transmission costs).

Under the proposed access model, the proceeds from FTR auctions will be used to reduce the direct transmission costs paid by consumers, TUOS.

[6] COGATI Proposed Access Model Discussion Paper, page 73

FTRs would represent a fixed cost for generators (once purchased) and so will be included in the generator's long-run average cost (LRAC). Generators will likely require a return on investment on this long run average, on top of the NSPs' return on investment, increasing the total cost of the network to consumers. This is analogous to retail margins being represented as a percentage of total cost including network charges in tariff determinations.

This increase in LRAC across generators will need to be reflected in average energy prices, with the resulting increase in wholesale electricity costs offsetting the reduction in TUOS.

Generation investment

Current location signals are working, but other factors remain important

One of the purported shortcomings of current arrangements is that the locational signals provided by loss factors are not strong enough. The amount of discussion (including a rule change request) which has arisen following recent downgrades in Marginal Loss Factors appears to contradict this view. There is a strong push to halve the current locational signal through a change to average loss factors[7] precisely because the signal is strong.

Congestion is only one of the factors that inform the locational decision of new generation projects. Access to and cost of other inputs - fuel, land and workforce - is also critical in locational decisions.

Losses are proposed to be addressed but no detail as to how.

The discussion paper indicates intent for FTRs to provide a hedge for loss factors; however it is unclear how the product would do so.

Losses are a result of physical (or modelled) flows across imperfect conductors. Losses *should* change based on system conditions – greater flow and greater distance will increase losses.

A product to hedge this risk is conceptually quite different to a product that hedges the price risk between two points in the network. It may take the form of a guaranteed loss factor at the time of investment, or shifting the cost of losses to another party who does not hold FTRs but either approach is likely to make the real-time signal less reflective than the current arrangements.

Potential for change from RRP to VWAP to actually dilute the locational signal

Changing the wholesale price from a Regional Reference Price (RRP) to a Volume-Weighted Average Price (VWAP) may dilute the location signal as a low local price will influence the regional average. As such the difference in prices will be less than under an RRP approach.

[7] Stanwell does not support this proposal as it appears to retain all the problems associated with unpredictable year-on-year loss factor publications and decreases the signal for new entrants not to invest in weak or congested areas.

3-4 year advance procurement provides fleeting protection against the impact of new entrants

The proposed 3 to 4 year auction lead time provides little protection for generators against a new entrant locating in close proximity and causing network congestion and increased transmission losses. For example, a solar farm in a relatively uncongested area of the grid will still be impacted by a new entrant solar farm locating nearby and increasing losses and congestion.

FTRs will only delay these impacts by a few years until existing FTRs expire. That is, in the 4th or 5th year (or likely earlier if intending participants can purchase rights in an auction) the incumbent will be exposed to greater losses, greater congestion and greater competition for transmission rights, logically increasing their price. These impacts cannot be forecast or hedged in a materially better way than under current arrangements.

The limited protection against new entrants crowding transmission capacity is inconsistent with the long-term operational decisions generators have to make in order to remain in the market, including maintenance planning, fuel contracting, retirement decisions and rehabilitation.

Short term auctions provide limited benefits at investment/financing timeframes.

The proposed 3 year tenure of FTRs does not provide a sufficient level of certainty for new projects that would be expected to result in a lower cost of capital.

FTRs represent a fixed cost for generators (as they do not vary with changes in electricity generation), so are likely to be treated as a non-current liability or lease. This would likely increase the amount of equity required for a project, increasing the weighted average cost of capital or the revenue requirement to achieve minimum debt service coverage ratios.

FTRs may even increase the cost of capital for new projects, as financiers penalise potential projects on both unsecured volume (i.e. any shortfall between FTRs and expected capacity) and the variable firmness of the FTRs they have purchased.

Grandfathering

Stanwell acknowledges that the development of grandfathering provisions for incumbent generators needs to occur in tandem with the development of the access model, but given the importance of these provisions for the long-term decision making and business planning, participants need a firm indication of the probable volume and duration of FTRs they can expect.

The challenge for the Commission is how to develop grandfathering provisions that provide firm access to incumbent participants in areas of the network that are already experiencing significant congestion.

Time and volume

The volume and length of FTRs provided to existing generators under grandfathering provisions is critical in delivering the proposed benefits of the reform. Short duration or low volumes of grandfathered access would leave incumbent generators exposed to the impacts of congestion and increased losses caused by new entrants while also exposing them to the increased risk of a different market design than the one they invested in.

Proposal to scale quickly replicates the problem FTRs are intended to solve

If the intent is to avoid the negative impacts of increased losses and congestions being observed in response to new entrants locating in relatively weak or heavily utilised areas of the grid, grandfathering should be on a "first-commissioned, first-served" basis and provide long term certainty commensurate with the expected life of these long-lived assets. The concept that it needs to be scaled quickly to reflect the current risk undermines the proposed benefits.

In order to balance the benefits of grandfathering with the desire to ensure rights are available for auction, Stanwell considers a process of graduated allocation could occur, for example:

- No more than 80 per cent of existing transmission capacity to be allocated under grandfathering arrangements; and
- No more than 80 per cent of nameplate capacity is grandfathered to any plant
    - Incumbents are allocated 50 per cent of nameplate capacity in order of commissioning date followed by up to three 10 per cent increments;
    - If a generator cannot be allocated access to one of these levels the process continues for other plant
- Grandfathered access remains valid until the earlier of the nominated closure year or 25 years.
    - Alternatively the first tranche (up to 50 per cent) could be longer than subsequent tranches.

Generators face greater risk when unhedged

Generators / market participants who are unhedged and do not hold FTRs would receive revenue based solely on their local marginal price which may or may not be aligned with the regional price. The local price is both more difficult to forecast and more susceptible to being impacted by individual investment and operational decisions of a competitor than the regional price.

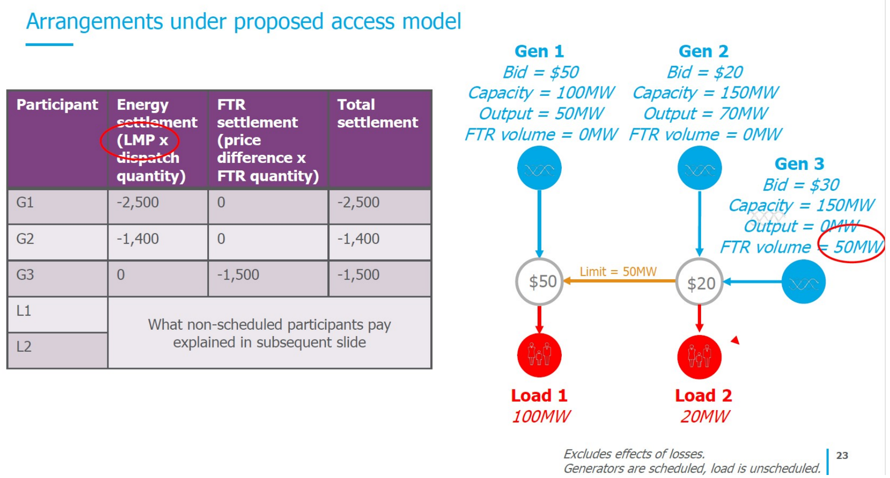
The reliance on local pricing may also exacerbate the "missing money"[8] problem which is only overcome if generators are able to rely on periods where a higher cost competitor sets the price in order to recover their fixed costs. Denying generators access to some of these periods of higher prices will mean they need to raise their own offer prices in order to recover fixed costs, potentially impacting on dispatch efficiency.

Generators without FTRs face greater risk in hedging

Under the proposed reform generators who do not have FTRs are disincentivised from selling hedge contracts against the regional price because of the increased risk.

This can be identified in the examples provided by the Commission.

[8] For example see Hildmann (2015). *Empirical Analysis of the Merit-Order Effect and the Missing Money Problem in Power Markets with High RES Shares*.
Newbery (2015). *Missing Money and Missing Markets: Reliability, Capacity Auctions and Interconnectors*.



Participant	Energy settlement (LMP x dispatch quantity)	FTR settlement (price difference x FTR quantity)	Total settlement
G1	-2,500	0	-2,500
G2	-1,400	0	-1,400
G3	0	-1,500	-1,500
L1	What non-scheduled participants pay explained in subsequent slide		
L2			

Gen 2 is the lowest cost supplier (as measured by offer price) but would be financially exposed if it had sold hedges at the RRP or VWAP. It would be receiving $20/MWh but paying $45/MWh (VWAP) or $50/MWh (RRP) under its contracts.

While Gen 3 may sell contracts based on the protection from basis risk offered by its purchased FTRs these are likely to be at a higher cost than the hedges that would otherwise be supplied by Gen 2 (assuming the higher offer cost is reflected in a higher long run cost).

Generators with FTRs retain the risk that they are non firm

Where a generator holds FTRs and has sold hedges it retains the risk that the FTRs are non-firm at a time when the local price is lower than the regional price. As identified under *Transmission Investment*, this non-firmness may arise due to events in other parts of the network preceding a curtailment of the access directly relevant to the purchasing generator.

The discussion paper indicates that this risk will be managed by reducing the number of FTRs available (which creates a different risk), however there will always remain a risk if the rights are financial but not firm.

Generators may not be able to purchase their desired level of FTRs

There are likely to be areas of the network (or potentially the whole network) where there are insufficient FTRs available to meet generator preference. This limitation is likely to be both physical and risk-based as NSPs will be required to determine how many FTRs are available given the current and committed network while aiming to maximise firmness.

In these areas generators are likely to face the twin prospects of having to pay a high price for FTRs or being unable to secure FTRs. For a given network configuration, increasing the availability of FTRs would decrease their firmness, shifting the risk from not having valuable rights to having not-valuable rights. Under any of these risks, issuance of hedge contracts would likely be restrained.

Generators purchasing FTRs have an increased project cost

The proposed access reform will transfer how transmission costs are recouped from customers by decreasing TUOS and increasing generator LRAC.

Generation projects will need to recover these increased costs, either through an increase in their energy bids (when they affect price), an increase in competitor's bids that affect their local price or residues from the FTRs themselves. Any increase in wholesale prices without a visible increase in short run prices is likely to perpetuate the negative media and policy cycle currently afflicting the market.

Generators face greater profit and loss volatility

In the current market design generators who sell hedge contracts typically attempt to assign them as *effective* under Australian Accounting Standard AASB 9 Financial Instruments[9].

> *"Hedge effectiveness is the extent to which changes in the fair value or cash flows of the hedging instrument offset changes in the fair value or the cash flows of the hedged item."*

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[9] AASB 9:B6.4.1 www.aasb.gov.au/admin/file/content105/c9/AASB9_12-14_COMPdec17_01-19.pdf

As both generation and contractual terms contain a reference to the same spot price, standard derivatives can attract an effectiveness of up to 100 per cent[10].

If a hedge cannot be designated as effective, or can attract only partial effectiveness, the changes in mark-to-market valuation of that contract will affect the volatility of the generator's profit or loss.

Equally, it is unclear whether and how the FTRs would be accounted for, both in terms of profit and loss reporting and retailer reliability obligations.

"race to the floor" bidding may not be affected

Much of the recent investment in generation assets has occurred where a long term offtake agreement was able to be committed to as part of the final investment decision. These agreements reduce the risk to the investor and their financiers by reducing or removing their exposure to unpredictable pool price outcomes.

A common offtake arrangement is a whole-of-meter swap whereby the investor is incentivised to maximise generation in order to receive maximum revenue. Early versions of these agreements incentivised volume maximisation in all market conditions while contemporary agreements are reported to include some exceptions such as during periods of negative wholesale price.

Where such a clause is included to protect the buyer it is likely to remain referenced to the regional price rather than the generators local price. Accordingly, where the regional price is positive the generator may remain incentivised to maximise dispatch volume regardless of the local price in order to receive revenue.

If multiple such plants are behind a constraint is it likely that their bids will reflect the incentives rather than their short run cost as assumed in the Commissions examples.

[10] Not all products will attract full hedge effectiveness and not all contracts of a given product may be eligible for full effectiveness.

Financial market liquidity

Current hedge limits include transmission risk but more likely to be constrained by outage risk or inherent plant limitations (intermittency).

The Commission may be overestimating the positive impact of FTRs on contract market liquidity.

Generators typically consider a number of inputs such as planned and unplanned outage risk, fuel constraints, desirability of spot exposure compared to the current contract price, losses and congestion when determining a maximum hedge volume to offer.

While FTRs may reduce the impact of congestion (and potentially losses) they do not address these other factors. However a *lack* of FTRs held by a generator may decrease their willingness to sell hedge contracts which are settled against a price they are not receiving for their generation.

As such the volume of contracts offered is only likely to increase if

- congestion risk was the factor limiting existing hedging; and
- the generator could secure sufficient FTRs; and
- the FTRs were considered highly firm; and
- the contract price was high enough to offer a return on investment including the cost of the FTRs.

For any generators where these four conditions are not met, the risk is skewed to a reduction in hedge volume being offered. While the overall impact is difficult to quantify, Stanwell considers that the strongly positive commentary in the discussion paper is unsupported.

Introduction of VWAP likely to be price disruption event

The move from Regional Reference Price (RRP) to Volume-Weighted Average Price (VWAP) appears likely to be a price disruption event for International Swaps and Derivatives Association (ISDA) based financial contracts, allowing any affected contracts (both hedging contracts and Power Purchase Agreements) to be reopened.

This has the potential to significantly change the risk profile and financial viability of parties to long term contracts such as Power Purchase Agreements (PPAs).

Dynamic loss factors

While the Commission has indicated an intention to design FTRs that protect generators from loss factor volatility, the discussion paper appears to retain the concept of loss factors as part of the market in some form. Specifically, the Commission proposes to move from annual average marginal loss factors to or towards dynamic loss factors.

Unclear interaction with existing rule change request and AEMO review.

Stanwell note that the Commission are currently considering a proposal to weaken locational signals through a change from marginal to average loss factors, and that any such change would likely precede the implementation of CoGaTI, but not by much. The potential for two changes to a single market design element to occur in a short timeframe, sending opposing signals is likely to have a negative impact on investment certainty.

Unidentified impact on existing processes – day ahead price submission

Generators currently submit offer prices before 12:30pm on the day preceding the trading day which are then fixed for the trading day. The prices are submitted at the generators connection point but must fall within the reliability settings (Market Price Floor and Market Price Cap) once Marginal Loss Factors are applied. That is, the offer price at the node must fall within the allowable market price range. Offers that do not conform are deemed corrupt and rejected entirely by AEMO’s systems.

The introduction of dynamic loss factors will mean generators are no longer able to ensure their day-ahead bids are within the Market Price Cap (MPC) and Market Floor Price (MFP) (i.e. not a corrupt bid). Typically a discussion of dynamic loss factors includes consideration of allowing bids to be priced “at the node” in order to avoid this issue, however it is unclear whether this approach would remain relevant under the VWAP proposal.

Ex-ante loss factors set for at least one trading day would overcome the issue of bid conformance. Dynamic loss factors or ex-ante loss factors published close to real time also appear likely to increase the volume of “late rebidding” as participants adjust their bids to incorporate new information.

If the proposal is to progress to a rule change this issue would need to be identified, solutions considered and costed in order to determine whether the proposal provides a net benefit to consumers.

Miscellaneous design elements

Scheduled load nomination

Where one side of the market is to be granted the option of facing local or regional prices Stanwell support the Commission seeking to balance the benefits of that freedom against the cost and complexity imposed on other participants.

While the proposed 12 month minimum period between loads being able to switch between scheduled (i.e. facing the local price) and non-scheduled (i.e. facing the regional price) appears appropriate to avoid "cherry picking" behaviour it is likely to be insufficient overall.

Consideration needs to also be given to the lead time for such a change to be requested, the impact on issues such as RRO liability and the firmness of qualifying contracts in respect to that liability and whether a load which is technically capable of being scheduled should be required to provide information to the market operator in relation to its capability and intent if it were to revert to non-scheduled status.

Alternatives to VWAP

The Discussion Paper suggests a couple of alternatives to VWAP, namely:

1. *to cap the local prices at the regional reference price (as currently formulated), or*
2. *scale local prices down or uplift the regional reference price (as currently formulated). (page 38)*

Stanwell does not support the first because it would distort the investment signal for new investment in areas that would have high electricity prices in the absence of the cap. A cap would also replicate the current incentive for generators to bid unavailable when dispatched against a high local price during periods of low regional price, which is one of the stated behaviours this reform process aims to address.

Stanwell does not support the second option either because scaling down LMP would dilute the locational signals the proposed access reform aims to provide and not fully reflect the value of electricity at each connection point. Scaling up RRP would increase costs to consumers.

Ex-ante offer cap

The ex-ante offer cap for pivotal suppliers should be rejected on substantially the same basis as the Commission rejected the 2013 rule change request for a similar mechanism.

The current Market Price Cap is an ex-ante price cap determined by the reliability commission based on providing a low utilisation peaking generator an avenue to recover its costs.

An additional ex-ante offer price cap is likely to exacerbate the missing money problem in gross pool markets.[11] If the last (pivotal) generator cannot charge significantly above its SRMC very occasionally, then it cannot recover its fixed costs. Similarly non-pivotal generators recover a portion of their fixed costs when a higher cost generator sets price, allowing them to offer capacity at a lower price more often than would otherwise be the case.

The Commission has not provided an explanation of why the AER's wholesale market monitoring functions and processes are not sufficient to address any market power concerns under the proposed access model, necessitating an additional ex-ante offer cap.

Auction and FTR design

While the overall proposal is incomplete the indicative auction design appears broadly appropriate given the information currently available. That is, an auction designed around simultaneous feasibility, value maximisation and linked bids appear logical even if unwarranted.

Either cleared price or pay-as-bid auction formats work in theory however Stanwell note that the cleared price approach is conceptually aligned with NEM design and the current SRA process (on which FTRs are substantially based) and so is likely to be preferable given the relative lack of difference in overall efficiency between the approaches.

Stanwell recognises the concept of the auction supporting bids for a small number of time-of-day products in addition to continuous FTRs however notes the risk of existing definitions becoming redundant. For example the current definition of peak (7am – 10pm working weekdays) evolved from

[11] Professor George Yarrow, assisted by Dr Chris Decker, *Bidding in energy-only wholesale electricity markets*, November 2014

the demand patterns observed early in (prior to) the market but are less relevant to intermittent generators who generate when there is fuel available, 7 days a week.

Tension between allowing intending participants to bid in auction and limiting procurement to capacity

The capacity and configuration of a potential project can change over the course of its development. As it is proposed that Intending Participants will be able to participate in FTR auctions there will need to be clear rules around the extent of that participation and the consequences of project changes after an auction.

For example, an intending participant who secures FTRs three years ahead to align with the expected first year of operation of their project may not ultimately be a “generator” entitled to hold those FTRs if the project is delayed. While the participant may offer the rights into subsequent auctions there is no guarantee that they will be sold (assuming a reserve price is applied).

A nearby generator may be unable to secure their preferred level of access or may have to pay an unnecessarily high price for access as a result.

Tension between generator FTRs and inter-regional FTRs

The proposal to allow a generator to purchase FTRs from their connection point to any regional price appears to overlap with the proposal to auction FTRs between two reference prices to a wider audience.

It is not clear how the volume of FTRs between two VWAPs (as opposed to two fixed locations in the network) would be determined, but it is likely that the existence of generator access rights across a subset of the connecting network would influence the volume.