2019 COGATI IMPLEMENTATION

Response to AEMC Access & Charging consultation paper

March 2019

1. Introduction

Thank you for the opportunity to provide feedback to the consultation process on the implementation of access and charging reform as part of the Coordination of Generation and Transmission Investment (CoGATI) review.

Stanwell understands that the Australian Energy Market Commission (AEMC) is not proposing to launch into the implementation of reform measures, but is seeking advice on specific details of the measures and their appropriateness. This is particularly relevant in the current climate where large market reforms are being developed and implemented, including the five minute settlement process and market making arrangements. In this respect, Stanwell is disappointed that the Supplementary Information Paper was based on the premise that this particular reform is necessary in the short-medium term without setting a strong case for why, or assessing other solutions.

Stanwell agrees with the AEMC's premise of a need for regulatory frameworks to adapt to the changing environment, however, this needs to be holistic and more considered rather than perpetuating the emerging dichotomy of planning the network to one standard but expecting it to operate to another. Before any network access and charging reform is designed, it needs to consider:

- What is appropriate for the largely hub and spoke structure of the National Electricity Market (NEM).
- Impact on participant risk management (the contracts market) rather than limiting consideration to the spot market. The proposals introduce a level of basis risk and it is not clear how this risk is reallocated.
- Interaction with other reform processes such as market making arrangements, Retailer Reliability Obligation (RRO) and the five minute settlement implementation (5MS). In particular, the feasibility of the Australian Energy Market Operator (AEMO) implementing the required changes to dispatch to facilitate sub-regional pricing in parallel with the 5MS implementation.
- Interaction with state and federal government policies. For example, where the State government has uniform tariff policies.
- The treatment of distributed energy resources (DER) including their contribution to congestion at the transmission level, and their use of the network if, and when, participating in the market.
- How the measures that coordinate better generation and transmission investment also facilitate effective system operation. For example, it is

unclear how dynamic pricing reflects different types of operational constraints other than congestion, nor considers the provision of system services. Similarly, it is unclear how firm access can be granted freely without potentially compromising system.

- Clearer and consistent objectives of reform.

Stanwell agrees that there is an urgent need for greater transparency of information for new generation seeking connection, and that investment should be optimised by allowing for generation to "share" requirements. However, the timing and sequencing of the AEMC's proposed phases is sub-optimal:

- Transparency of information is needed now, and many if not all of the available avenues already exist. AEMO and the Transmission Network Service Providers (TNSPs) have data that can provide the desired signals. Existing processes should be modified and utilised to facilitate investment signals to industry. Ideally this information would be available through existing interfaces such as the AEMO infoserver, Electricity Statement of Opportunities (ESOO) and the Integrated System Plan (ISP). Alternatively this could be a regular update in the form of heat maps or data.

  It was also discussed that the business models for new generation seeking connection are impacted by the lack of visibility of other potential connecting parties, or access to information. Two rule change requests were submitted late last year by the Australian Energy Council (AEC) and AEMO respectively to address these particular issues. A third rule change request was submitted in March by Energy Networks Australia (ENA) to allow TNSPs to publicise greater information about potential parties seeking to connect to their network.

- More immediate regulation changes would assist in facilitating "shared access" to resources. For example, if a generator negotiating a connection requires synchronous capabilities for system strength or otherwise, it may be more efficient for that generator to contract those services from a local synchronous generator or condenser. However, there are barriers to tripartite conversations in the current processes, making it difficult to enact this more efficient solution. The ENA rule change request helps address this barrier.

- Given the identified need to coordinate transmission and generation investment, it seems illogical to consider these aspects in separate phases with separate timings. They need to be considered holistically.

In the submissions to the CoGATI review, the Clean Energy Council, TransGrid and ENA all indicated the priority was to action the ISP and not to undertake major reform. Given these organisations represent those parties "most affected", the AEMC should delay any consideration of major transmission network reform until the current processes and reforms can be assessed. In the meantime, Stanwell suggests that the AEMC should undertake the following program of work in this area:

Increase transparency of information	Request analysis from AEMO and TNSPs of information that could reflect congestion: - Transfer limits - Constraints invoked - Dynamic regional prices (where available) Formalise a reporting requirement for AEMO and TNSPs to publish this information.
	Progress rule change requests to regularly update Generator Information Page (GIP) and provide access to information to developers, and allow TNSPs to disclose greater information.
Regulatory barriers	Assess current regulatory barriers to accessing alternative solutions to network investment for new connections

Stanwell welcomes the opportunity to further discuss this submission. Please contact Alison Demaria on (07) 3228 4588.

2. Context

The CoGATI report, consultation paper and further supplementary information do not provide a demonstrable need for the proposed changes, nor have other options been explored. The supplementary information paper in particular sought to address questions raised by stakeholders but ultimately finished by adding to the number of questions.

Stanwell agrees that transmission and generation investment should be coordinated, but more thought needs to be given to the potential frameworks and their appropriateness. In particular, long-term signals need to consider the interaction with system security needs.

Of the seven issues needing to be addressed that were identified in the supplementary paper, none are solved effectively by the proposed changes in arrangements, and most require significant further work to detail a potential solution.

Given the frameworks are yet to be detailed or justified, the CoGATI process is adding to the investment uncertainty created by the ESB's mid 2020s market reform process. There is no certainty that any changes to access and charging arrangements implemented by the AEMC will be compatible with the market design changes recommended by the ESB.

In the absence of clear assessment of the outcomes of access and charging reform as proposed, Stanwell urges the AEMC to focus on implementing changes that will add benefit in the next few years such as increasing the transparency information.

Consideration also needs to be given to the implementation processes currently underway and how these proposed changes will impact them. For example, the 5MS process is a major task underway across AEMO and industry. Presumably the introduction of dynamic regional pricing would require significant changes to the same systems affected by 5MS.

3. Dynamic Regional Pricing

How dynamic pricing would work

Dynamic regional pricing as outlined in the consultation report would be created through dispatch based on the transmission constraints at that time. In each dispatch period where a constraint occurred, generators would be paid the dynamic regional price that applies where they are connected instead of the regional reference price. Conversely, market customers would still be settled at the regional reference price. Generators would also get a share of revenue that arises due to the difference between the two prices, allocated dynamically based on capacity.

The AEMC states that a generator's access arrangements would be changed to implement dynamic regions for determining the price payable to generation. Stanwell would like to understand:

- Whether this applies only to new connections from a set date in time, or whether all incumbent generation will be affected.
- If it is applicable to new generation, will it later apply to existing generation when they renew their network access authorities with relevant TNSPs? These typically require renewal every 10-15 years and if dynamic pricing will then apply, it may affect the planned closure dates of some generation.
- Will generators connected to the same connection point have the same dynamic price, regardless of when they connect or will a "congestion ratio" be determined at the time of connection.
- How the dynamic regions will be determined and whether they are static. Stanwell presumes that the dynamic regional price would be determined by the dispatch process and rely on the constraint formulations that AEMO produces as well as the shadow price of generation at that node. If this is so, it would be pertinent to determine whether the implementation of dynamic regional pricing in the NEM dispatch engine (NEMDE) is not only feasible but efficient, noting that the constraints process is already complex. Similarly, whether this pricing would be included in the predispatch process.

  It would also be prudent to consider the challenges of implementing such a reform in parallel with the implementation of the 5MS process.
- The interaction between dynamic regional pricing and Marginal Loss Factors. MLFs incorporate losses across lines which would no longer be relevant to the determination of the sub-regional price being paid to the generator. MLFs also impact extra-NEM issues such as creation volumes for Large-scale Generation Certificates (LGCs).

Proposed benefits of dynamic regional pricing can already be achieved

The consultation paper claims the benefits of dynamic regional pricing will be the provision of locational investment information, reflecting short-run costs of using the network and removing disorderly bidding incentives.

Stanwell agrees with the need for locational investment signals but argues that the first two benefits may already be achievable currently as the necessary information is with the relevant market bodies. The AEMC should focus on facilitating access and transparency of this information.

AEMO and the TNSPs already have the information about when and what constraints are imposed, and transfer limits on interconnection. This information could be reported on either through a regular process such as the ISP, dynamically on their website or provided to intending participants upon request. While not as ascetic a metric as price, it still represents the same information and is already accessible. This is much more favourable than the information being available in the proposed phase 2 in mid-July 2023 particularly given the present number of connection enquiries.

In some instances, local prices arising from congestion may already be available at little effort (for example shadow prices on NEMDE constraints) and Stanwell would also support the publication of this information where feasible at low cost.

Being a reflection of short-run costs of using the network, dynamic regional pricing does not provide any greater advantage than the existing information in terms of locational investment signals. The forward “congestion risk” would still exist and as it changes dynamically with each dispatch and investment in supply, there still is little predictability.

Congestion concerns have also focused on the lack of transparency of new projects also seeking connection. Two rule changes were submitted in late 2018 to address these issues, and a further rule change request in March 2019:

- AEMO submitted a request to redefine intending participants to allow developers to access necessary information about the network.
- The AEC’s request focused on placing requirements on developers and others to register intent to connect, and for more regular updates of the GIP to provide industry with greater transparency of potential projects.
- ENA submitted a request to relax confidentiality of information arrangements on TNSPs in order to facilitate transparency of projects seeking connection to the network.

Concerns of the proposed dynamic regional pricing

The current CoGaTI proposal does not adequately consider the rationale for reform, and how it fits within the broader operation of the power system and energy market. The Supplementary Information Paper serves as further evidence of this, with many of the responses to how access reform will address the identified issues admitting that adequate assessment had not yet been made.

Some of the concerns include:

- **Type of constraint** – constraints can be invoked for a variety of reasons other than congestion and need to be considered in any pricing structure based on constraints. The simplification of thermal and non-thermal constraints does not appropriately reflect the complexity of the non-thermal constraints and how they may impact on generation. For example, if AEMO pursues regional enablement of Frequency Control Ancillary Services (FCAS), then frequency control constraints may be invoked relatively often to ensure certain generation is online.
- **System services** – this model simplifies the signals that the power system needs now and into the future. Not all MWs are equal in an operational sense, and there is no clarity over how they are considered in this model and how system services are accounted for or could be accounted for.
- **Marginal Loss Factors** – Stanwell agrees that while not a static measure, MLFs should be more transparent. Also there is a need to consider how they will interact, if at all, with dynamic regional pricing and sub-locational regional pricing. The AEMC suggested that MLFs could be incorporated into the regional price. To do so effectively would require careful consideration of how it would be implemented within the dispatch process. MLFs are determined based on the physical losses associated with transporting energy through the network. These will still need to be priced into periods with no congestion.
- **Consideration of DER** – increasing levels of installed DER contribute to congestion at the transmission level at times. How this gets considered is still unclear. While Stanwell welcomes the AEMC’s consideration of large-scale generation connected to the distribution network, any reform process needs to adequately consider the growing levels of DER which at times, can represent a significant portion of the generation mix. For example, South Australia has already experienced times when rooftop solar generation exported to the grid has represented close to 50 per cent of operational demand. This also has the flow-on effect of increased reliance

on interconnection. Any reform needs to look at effectively integrating distribution and transmission planning.

- **Generator risk management –** Does the compensation to generators on settlement price adequately mitigate risk of hedges under this arrangement?
- **Liquidity and financial markets analysis –** there has been little consideration of how this real-time approach interacts with the contracts market, and how it affects hedging.
- **Market making and RRO** – there has been no consideration of how this interacts with market making mechanisms currently under consideration by the ASX, ESB and the AEMC. Furthermore, it is unclear how hedging under the RRO will be affected, for example a retailer's compliance is based on load measured at the node but will change year on year as MLFs change. Generator market making obligations are based on installed scheduled capacity in a region with no differentiation as to where in a region the capacity is.
- **Disorderly bidding** – without proper assessment, it is hard to consider the effects of disorderly bidding, and whether inefficiency in dispatch is caused by it, or by a secure and reliable operation of the network overall. Stanwell notes that both the good faith rebidding and 5MS rule changes were intended to reduce disorderly rebidding. While the AEMC discussed how 5MS would not address disorderly bidding due to congestion, it still raises the question of how much benefit could arise from CoGaTI also addressing this issue after the implementation of the two reforms.

Treatment of storage

Storage should not be treated any differently to generation - part of the premise of the storage registration rule change is to facilitate storage's participation in the market on par with generation. This would extend to storage settling alongside other market customers at the regional reference price instead of the dynamic regional price. If not, this would:

- Violate the technology neutrality of the rules unless it applies to all types of storage such as pumped hydro and batteries.
- Perversely incentivise storage-based consumption differently to non-storage based consumption at the same site. This may lead to unintended approaches to energy arbitrage.
- Provides other forms of demand response an unfair advantage over storage.

Overall benefits of dynamic regional pricing

The analysis in CoGATI and the consultation paper is over-simplified. Many of the benefits are short-term which is in conflict with the long-term nature of investments.

Many of the examples only consider an individual generator or connection point of the system, and fail to capture the holistic dynamics required to make a proper assessment of the required reform, if any. One of the arguments used was that congestion causes cost-effective generation to be constrained off. This may be true for a limited period, but without knowing why they are constrained off, what services they provide the power system and the other components of the system, this is hard to justify.

Furthermore, Stanwell does not understand how dynamic pricing will always discourage disorderly bidding. The examples given had two generators of the same capacity affected by the constraint, however, if the generators were different capacities, there would still be an incentive (albeit smaller) to disorderly bid. This is just one example of the incentive for disorderly bidding remaining despite the regional price exposure.

If implemented, dynamic regional pricing would lead to locking in the current regional reference price framework which may or may not be the most efficient long-term. Given all the work underway by the ESB, AEMC, AEMO and COAG Energy Council, it is hard to argue what the required pattern, location and timing of transmission and/or generation investment is until the reform objective is clear. In the meantime, focus should be on improving the ISP such that it provides the relevant investment signals to industry, and increasing the transparency of information to industry.

4. Information from dynamic regional pricing

Phase 2 of the proposed reform involves information about patterns of congestion and dynamic location of regions, and the costs associated with congestion. The intent is for these to be incorporated into the ISP and to inform TNSP decisions.

As per above, Stanwell finds it difficult to understand how this information cannot already be derived from AEMO and TNSPs. Constraint information can be obtained from NEMDE and transfer limits on transmission lines from TNSPs. It may be beneficial for the AEMC to request analysis from these bodies to provide an initial assessment of congestion and potential costs. This would also have the advantage of including an assessment of the types of constraints invoked, the types of investment needed, and actual dynamic regional pricing could be published without applying it.

This information, provided to industry on a regular basis would be useful in advance of the proposed phase 1 reforms, and certainly prior to 2023. The information is likely to inform the potential risks and benefits of the proposed reforms and be much more useful in relation to planning the current and next waves of investment.

5. Generator firm access

As stated in the consultation report, access reform has been an ongoing discussion. AEMC's proposal involves generators being able to buy "firm" transmission rights which would see them receive compensation if constrained off. Proponents would be able to purchase access that notionally underwrites transmission investment required to facilitate that connection.

The anticipated benefits outlined in the consultation paper consist of the alignment of generator and transmission investment, reducing costs to consumers and generators bearing the investment risk.

While firm access may be a feature of international systems, these systems are in many respects different to the hub and spoke nature of the NEM.

Practicalities of generator firm access

Stanwell would appreciate clarity on a number of elements of the proposed reform and how it would work should it be implemented in phase 3:

- **Grandfathering** – The supplementary paper provided some information on access rights for existing generation, but fell short in guaranteeing firm access until plant closure. The AEMC has suggested a period of transitional access after which a process of paying for access would be established. Stanwell had been expecting that there would be a date set for which all existing generators connected prior to that time would be guaranteed 100% firm access (up to current network capability) until closure so as to not create uncertainty in the market. If a sunset clause is established on the existing access regime, then the process of allocating access rights needs to factor in the services additional to energy that are delivered by existing generation. Access rights should not be based on peak demand only, or rely on auction processes unless they appropriately consider the level of value of the plant to the system.
- **Network Process** – would the TNSP have to undertake a RiT-T process or similar to assess whether the new investment is more cost-effective than compensation.

  Also, would the TNSP be obliged to consider each case as they arise or would there be a process whereby the TNSP considers a group of connections in a location and facilitate shared investment? If so, is this at the TNSP's discretion or will there be an accountability or governance role for the AER?

  The supplementary paper did briefly discuss some options but given the criticality of this component, it would be useful to have greater information.
- **Connection process** – if a new connection is paying for firm access, would this grant them an accelerated connection timeframe, thereby potentially "jumping the queue". If so, this would then exacerbate the current risk to other connections of their business cases changing, an issue this reform is trying to address.

  Furthermore, Stanwell struggles to understand how firm access would address the volume of connection enquiries being received. Most of the benefits here may be achieved with the transparency of information about the connection proponents.
- **Compensation** – clear frameworks for compensation for being constrained off would need to be considered given the variety of reasons that constraints are invoked. This would also need to be consistent with the treatment of existing generators who do not get compensated for outages or constraints. Compensation should only apply if and when that generator is constrained due to congestion on that network.

  Depending on how the framework is designed and what constraints are within the control of networks, there is a risk that these arrangements will be highly inefficient, and the compensation for constraints passed thru to consumers.
- **Coordination with system operations** – while this may coordinate transmission and generation investment at a particular network location,

there is no detail on how this would interact within system operations, in particular security considerations in the optimised dispatch. For example, generators with firm access may be constrained off by AEMO for security reasons or to enable generators providing FCAS, and thus the constraint is not congestion related. Here, the principles of firm access may not apply as generators are constrained by security constraints.

Firm access effectively decouples financial access to the market price from the physical dispatch, compromising system security. There is a difference between the network stability investment of firm access and secure dispatch that needs to be recognised.

- **Access rights** – need to be clear what access arrangements mean and how they could be coordinated to the system operational needs. Transmission rights could be tiered to what services the connecting party is providing, including services ancillary to energy.

  Also, can access arrangements only be purchased upon connection or could generators negotiate based on market conditions. What is the term of the negotiated access rights?

- **Cap on firm access** – will there be a limit imposed on the level of generation that has firm access. If not, there is a risk that the network will be over sized or that compensation costs would soar. Ultimately these costs will be borne by consumers as there will be a natural threshold of required generation.

  Consideration could also be given to granting a percentage of rated capacity firm access.

- **System strength** – Stanwell agrees that more efficient solutions exist to new connections investing in system strength solutions, and this will likely be addressed by greater transparency of information on parties seeking connection to the same network point.

  We struggle to understand how a benefit of access rights is the inclusion of a product which meets the generators obligation in relation to system strength. This is no different to the existing connection process and will not encourage shared assets.

- **Information** – the AEMC has suggested that generators with firm access would be more willing to share information. This will only be the case if there is an incentive or obligation to do so.

- **Renewable Energy Zones** – the AEMC needs to clearly distinguish between paying for shared assets in order to connect to the network and being granted firm access. Expectations for any generation seeking to be part of a renewable energy zone would also need to be managed.

Considerations needing to be explored

A number of potential risks of firm access in addition to the above can be identified without requiring the details on any arrangements:

- **Alternative solutions** – firm access should not pose an impediment to alternative solutions that will be more cost-effective. For example, barriers currently exist for solutions that consider a new generation connection contracting with another generator to provide synchronous services that are required as part of its connection agreement. In negotiating network access, the generator cannot establish tripartite negotiation arrangements within the existing framework, making the connection process protracted. There is a risk that any regulatory barriers that exist to more cost-effective solutions would be superseded by the TNSPs ability to accept underwriting of assets in negotiating access.

- **Performance standards** – there will need to be clear understanding that paying for access is separate to generator technical performance standards, with new connections unable to pay to connect with sub-optimal performance standards.

- **Treatment of DER** – will the same rules apply to DER connections or will they always have firm access. How this applies needs to be integrated into transmission planning and there should be clear rules to guide where firm access can be granted. In particular, if there are to be aggregations of DER and potential a distributed system operator function, how are they considered in any framework? DER is now a market participant whether directly or indirectly, and so will affect transmission access arrangements and compensation formulas.

- **Dynamic frameworks** – how will the frameworks change over time with system changes. For example, how to manage if load increases.

- **TNSP resourcing and processes** – would infrastructure that is underwritten by connecting generators be prioritised over common, centrally needed resources. In which case, this may have a flow-on cost impost to consumers.

- **Risk allocation for transmission investment** – the metrics for investment have changed based on the changing needs of the power system. Access arrangements make transmission companies take on the risk of not just locational congestion, but also system-wide constraints based on the compensation frameworks being considered. The TNSPs cannot make informed decisions on system security related dispatch requirements yet they own the risk of these impacting contracts for firm access.

Concluding comments on access reform

Stanwell does not consider the present arguments as persuasive to consider implementation of access reform. This process also cannot be considered separately to dynamic pricing as they will influence each other.

As stated by the AEMC, the transmission network is not planned to provide a particular generator with a specific outcome. The proposed access reform will result in a transmission network built for access arrangements not built for customers. Stanwell questions the economic efficiency of this approach and would encourage any compensation frameworks to adequately address times of excess supply.

6. Charging reform

The consultation paper poses a number of questions about how charging reform should look, and admits that there is a broader piece of work around tariff reform that needs to occur.

The questions posed in the consultation paper focussed on:

- Modifying pricing methodology to allocate costs based on average load as opposed to peak load.
- Including non-locational components of intra-regional investments in the inter-regional transmission charge, rather than smearing access the customers in that region.
- Whether the TNSP should be able to discount the non-locational elements of the inter-regional transmission charge.

Stanwell is concerned that the timing, sequencing and scope of the proposed charging reforms are inadequate and will lead to inefficient outcomes. If they are to be pursued, they need to be clearly articulated in context of their role in the broader review of network costs. This holistic approach would, for example, need to consider:

- Whether volumetric cost recovery is still appropriate given the changes in the system, and the role of the networks to transport system security services.
- Integration of DER in the assessment of network costs and benefits, and planning decisions.
- The role of interconnectors and their beneficiaries, as well as their influence on constraints.
- The market impacts of 5MS.
- How the implementation of access reform would affect the TUOS spend of networks, in particular the existing sunk investment.

Stanwell questions why charging reform would be implemented as a final stage. It should be progressed alongside the implementation of access reform if the intent is for more coordination between investments.

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