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To: AEMC
By website

Re: Response to Coordination of Generation and Transmission Investment Directions Paper

Infigen Energy (Infigen) welcomes the opportunity to make a submission to the Coordination of Generation and Transmission Investment (COGATI) Directions Paper. Infigen owns a 670 MW portfolio of wind capacity across New South Wales, South Australia, Victoria and Western Australia, is constructing a 25 MW / 52 MWh battery in South Australia and has entered into PPAs to provide an additional c90 MW of capacity in Victoria.

Infigen Energy (Infigen) welcomes the opportunity to make a submission to the AER Draft Interim Qualifying Contracts and Firmness Guidelines. Infigen owns portfolio of wind and firming capacity across New South Wales, South Australia, Victoria and Western Australia. Our portfolio includes 670 MW of vertically integrated wind plus Infigen has entered into PPAs to provide c90 MW of capacity in Victoria and is seeking PPAs in other regions). Infigen also owns and operates a 123 MW open cycle gas turbine in NSW and a 25 MW / 52 MWh battery in South Australia (under construction).

1. OVERVIEW

Infigen acknowledges that many possible models for transmission access are workable (and indeed are used around the world). However, the cost of any transition to a new model should not be underestimated, nor will any reforms be a panacea to coordinating future generation and transmission investment. While there may be gains in the spot market, we are concerned these will be more than offset by inefficiencies in the forward market. Damaging market liquidity risks breaking essential links between investment requirements and system operations.

Many recent investment issues have been exacerbated by the simultaneous build of multiple projects in a geographical area, without sufficient understanding of potential impacts. Greater information and potential strategies for coordinating new transmission assets could deliver significant value at minimal cost (provided the risks of underutilised assets are allocated appropriately).

Even *if* access reforms lead to improved investor certainty and lower costs longer-term, this must be balanced against the material costs incurred in the near-term. This includes implementation costs, but also the impact of policy uncertainty and potential queueing issues on project development, and the supply of hedges into the market. Even the possibility of reforms has increased the complexity of PPA negotiations (for Infigen as a buyer), and we consider it must also *increase* uncertainty for debt and equity providers over the short to medium term.

Understanding the true costs and benefits are critical, and we do not consider this has been adequately addressed to date. We also note that reforms in the gas sector have trended away towards more open access frameworks.

Notwithstanding those issues, in general, we consider the AEMC has accurately captured the key issues raised to date, and the updated settlement equations appear technically accurate. Infigen's key comments on the Directions Paper are:

- While we see limited benefits in pursuing dynamic regional pricing and transmission hedges, unlocking renewable energy zones and facilitating coordination appears tractable and beneficial provided underutilisation risks are allocated appropriately. The risk sharing models discussed in the Interim Paper could be a workable template, and this aligns well with the current focus on actioning AEMO's Integrated System Plan (ISP).
- Transmission reform for the bulk network should be deferred until the ESB's Post-2025 Market Reform work is complete, and until further clarity is achieved on work to action the ISP.
- Notwithstanding that recommendation, greater focus should be placed on assessing the most challenging issues first: cost-benefit analysis, transitional arrangements, and pricing of transmission hedges. These are the least well-defined parts of the previous Optional Firm Access (OFA) framework.
- Given that grid connection (both costs and timing) already drives major delays in delivering new capacity to the grid, AEMC should consider whether now is the right time to add further responsibilities and complexities (e.g., pricing of transmission access) to AEMO and NSPs for connecting new capacity (i.e. connection lags associated with the new requirements under s5.4.3a and s5.4.3b are currently running at 30+ weeks according to recent project delay analysis across 14 power projects).
- The AEMC should prepare a second interim report before the Draft Report, allowing further analysis and consultation on the key transitional issues. This second interim paper should provide:
    - Detailed discussion of possible hedging arrangements
    - Proposed transitional arrangements and impacts in light of existing transitional arrangements associated with grid connection
    - Quantitative analysis of the likely impacts on the existing network, including example cost calculations and available transmission capacity for several example nodes.

Infigen has provided some expanded comments below and has then responded to the questions in the Interim Paper.

2. INFIGEN COMMENTS

Cost benefit analysis

AEMC has not demonstrated clear costs and benefits. For example:

- as noted by the AEMC, *race to the floor bidding* appears responsible for at most $3-6m per year (based on 2025 to 2030 modelling), for an NPV of at most $30-60m (ROAM Consulting found an NPV of $8m); this was a key driver behind 5 Minute Settlement – the incremental benefits of transmission reform are presumably even lower.
- The previous OFA modelling found net benefits under a strong emissions target of around $400m, but this should be revisited in light of falling technology costs and greater uptake of energy storage.

The AEMC should continue to develop real-world examples of potential options for the current NEM (as was attempted at a high level under OFA), including where congestion is projected, what hedges could be offered, and the impacts on wholesale prices and any likely impacts on forward market liquidity. This includes how nodes will be defined, how delocalised system security constraints can be incorporated, and how incumbents could be treated.

Western Victoria may provide a useful case study: the AEMC could consider how pricing, dispatch, grandfathering, forward market liquidity effects and, ultimately, generation and transmission outcomes might be changed if access reforms were in place (say) five years ago. We expect this to be a significant modelling and analysis exercise (likely requiring cooperation across AEMC, AEMO and TNSPs), but one which is necessary if consumers and generators are to have an informed opinion on the benefits of the scheme. If a compelling case for COGATI cannot be made for Western Victoria (where the *prima facie* case appears prospective), then we query whether any further work is warranted on this policy initiative at all.

At a high level, AEMO's preferred upgrade option in Western Victoria[1] has a projected capital cost of $370m. This is to accommodate the ~2,000 MW of committed new renewable generation that will be built in the region by 2020 *plus* AEMO's projections of a further expected 3,000 MW by 2025 and a further 1,000 MW by 2030 (based on proposed new connections and the Victorian Renewable Energy Target).

[1] https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2019/PACR/Western-Victoria-RIT-T-PACR.pdf

If this cost were recovered from generators, a reasonable estimate[2] would be only ~$1.50/MWh from the 5,000 MW of renewable capacity projected by 2025, and $4/MWh if generation remained at ~2000MW. It seems unlikely that exposing generators to this cost would have materially changed investment decisions given the high quality resource in the region (and also noting the reduced curtailment resulting from these upgrades). For example, this is equivalent to less than a one percentage point decrease in average capacity factor.

On this high level basis, the existing planning infrastructure of transmission following generation seems likely to have delivered an efficient and comparatively low-risk outcome for consumers (at least in this instance).

Better utilisation of previous work under OFA
While we appreciate the AEMC's willingness to consider all options, significant and detailed design work was undertaken for Optional Firm Access (OFA). The AEMC should draw on the significant time and efforts of stakeholders (and the AEMC) throughout that process, and raise explicit commentary on where and how the current market conditions might lead to different conclusions. This could include references to the appropriate sections in Optional Firm Access, Design and Testing reports.

Pricing and transmission hedge products
How prices for long-term hedge products will be determined is critical. Grid connection is already the most challenging aspect of project development, with both AEMO and NSP processes (i.e. s5.4.3a and s5.4.3b processes) associated leading to very material delays – including delaying the introduction of flexible capacity into the grid, and increasing costs. There is also a significant information asymmetry, with project developers having little opportunity to negotiate connection costs or conditions.

A further obligation on TNSPs to effectively price deep connection costs on a per asset (or per "node") basis would further increase uncertainty around the "single point of failure" that is grid connection. Aligning generation and transmission builds (if required) will also be challenging. It is not clear that even the level of transparency and oversight currently provided for RIT-T assessments can be provided to long-term access pricing.

Transitional arrangements
We acknowledge that some level of grandfathered access rights (e.g., free allocation of transmission hedges) will need to be provided to existing generators: investments made in good faith under long standing Rules and market investment conventions

[2] Based on a 33% volume weighted average capacity factor, a real rate of return of based on a 5.36% nominal rate of return, and a conservative 25 year cost recovery period.

should not be disrupted, and new costs should not be arbitrarily imposed given existing (and often inflexible) financing arrangements made on this basis.

However, this needs to be balanced against any necessary system reforms. Providing grandfathered rights for the life of a plant would prima facie also appear to be inconsistent with the AEMC's premise that existing network access arrangements do not provide certainty. Participants do not currently assume that they will have unconstrainted access indefinitely - although in most cases, firms may make the credible assumption that material network constraints are unlikely to be imposed on existing generation assets given the bankability of new entrants relies critically no visible network constraints (i.e. an essential due diligence item for a project finance).

Again, this was discussed at great length under OFA. A 15-year grandfathering period may be a reasonable starting point. Alternatively, it may be appropriate to provide grandfathered access only up to a maximum plant life of (say) 20-30 years, reflecting the typical *economic* life of assets.

3. RENEWABLE ENERGY ZONES

In contrast to the unclear costs and benefits of reforming access to the existing network, the coordination of multiple generators to develop new shared transmission assets seems to be a more material near-term challenge in the NEM. We support progressing these proposals further and using this process to inform the need for broader transmission access reform. In particular, the risk sharing model presented in the Directions Paper has merit in that it:

- Recognises that there is (short- to medium run) value to consumers from new transmission to unlock generation resources;
- Allows AEMO to consider a holistic approach of future needs, including prospective projects and likelihood of connection (and alternative locations), but doesn't impose a centralised development plan;
- Does not imp
- ose the full cost or risk of developing transmission on any single party;
- Provides the opportunity for competition around transmission funding and pricing; and
- Facilitates a framework for governments that seek to fund transmission, if they see the need, through an established and transparent process that hopefully leads to less out-of-market intervention.

This framework avoids the need and complexity of providing firm access to generators: the tariffs reflect access to the transmission grid, and a limit on local competition, without guaranteed access along the shared network. In principle, this framework could be applied to other new transmission assets in the NEM.

The proposed framework seems plausible for access to new geographic locations. Reinforcing transmission to existing areas would need to be managed carefully to ensure undue costs are not imposed on participants who already intended to connect. Tariffs will also need to be set to ensure no participants can free-ride.

We note that the speculative component of transmission development (TNSPs developing above the level recommended in the ISP) may create mixed incentives if TNSPs are allowed to set prices at any level. For example, TNSPs would have an incentive to extract rent from the last generators to connect and to avoid building new (semi-)regulated assets that would be sold closer to cost.

4. RESPONSES TO AEMC'S QUESTIONS

AEMC question	Infigen response
QUESTION 1 ALLOCATION OF SETTLEMENT RESIDUES • Do stakeholders agree with the main advantages and disadvantages identified in relation to the different approaches for allocating settlement residues? • Of the approaches identified under each implementation scenario, which do stakeholders think best meets the design principles (set out in Appendix A)? • Are there alternative approaches that should also be considered under each implementation scenario? • What other factors or information would stakeholders consider relevant to determining the preferred approach?	While incumbents have not built on the basis of firm access to transmission, they have made reasonable assumptions about settlement and market rules. Not allocating settlement residues to participants without hedging contracts would have significant implications for existing participants, and a "slow start" transition would not be possible: • Hedging products would effectively become a mandatory requirement - problematic if the cost of hedges exceeded the value (i.e., incumbents would face a loss whether they buy hedges or not). • Participants without hedges would be strongly incentivised to withdraw capacity (from both spot and forward markets) to avoid constraints. • The AEMC would be obliged to provide at least initial grandfathering of hedges to incumbents to ensure existing investments are not disadvantaged. • This approach would either require very localised hedging products (to deal with local constraints) or would drive disorderly bidding. Subject to Infigen's comments in our previous submission, allocating residues on the basis of availability (Option A) seems most likely to support a smooth transition and allow hedging to be adopted organically.
QUESTION 2: SCOPE OF DYNAMIC REGIONAL PRICING • Do stakeholders agree with the above analysis in relation to the advantages and disadvantages of allowing different categories of market participant to be settled at locational marginal prices? • Do stakeholders consider that the scheduled / non-scheduled distinction offers a sensible	The AEMC's proposed approach of applying the local marginal price to scheduled and semi-scheduled market participants or the regional reference price otherwise seems reasonable. This is consistent with "price taker" philosophy behind non-scheduled units. As previously noted for Optional Firm Access, the cost of transmission hedges must necessarily be passed through to consumers. This will tend to drive up the cost of new entrants, driving *higher* wholesale and contracting prices, offsetting any reduced financing costs.

basis for determining which parties should face local or regional pricing? • Are there other impacts that should be considered in this decision? • What additional information do stakeholders consider would be useful to inform this decision?	
QUESTION 3: CHOICE OF REGIONAL PRICE • Under the proposed model, some categories of market participant would continue to face a common regional price. Do stakeholders agree that the issues outlined above are relevant for assessing whether this regional price should be the existing regional reference price or an alternative (for example, a LAP approach)? • Are there other issues that should be considered?	The proposed reforms introduce significant complexity to dispatch, settlement and the contracting market. Developing yet another reference price for settlement will increase complexity for existing contracts and will likely reduce contracting liquidity at least in the short-term.
QUESTION 4: LOSSES • Noting that the Commission will be considering the merits of different approaches to calculating and applying loss factors in relation to the Adani Renewables rule change requests, what are stakeholders' views of the advantages and disadvantages of the different approaches outlined above, in the specific context of the dynamic regional pricing model outlined in this chapter?	Given that losses in the network are driven by broader considerations than local congestion (or nearby investment decisions), we do not consider it appropriate to either socialise changes in losses over time or to somehow allocate all incremental to new entrants. Infigen refers the AEMC to its submission to the Transmission Loss Factor Frameworks rule change. We do support frameworks that may smooth loss factors over time.
QUESTION 5: EXPECTED IMPACT OF THE REFORMS • Do stakeholders agree that these issues are relevant in assessing the impact of dynamic regional pricing? • Are there other issues that should be considered?	Infigen agrees with the issues list prepared by the AEMC. Critical is the impact on forward contract market liquidity. Infigen is currently seeking to purchase PPAs from wind and solar projects and the AEMC’s proposal has already observed increased complexity around PPA negotiations. We consider that the need to manage new and unclear risks will likely slow investment in the near-term, and increase ongoing costs. AEMC also notes that dynamic regional pricing “does not introduce a new net risk to generators”. However, if settlement residues are not returned to generators, then the proposed

• What scenarios should be used as reference scenarios in considering market power concerns?	framework will introduce a new net risk to participants: i.e., if participants are not grandfathered hedging products then they may experience material revenue reductions relative to the status quo. We also recommend the AEMC consider how these reforms will impact the transition to a low emissions future. For example, how transitional arrangements could affect projects already under development, and further analysis on efficient transmission build and hedging strategies for wind and solar farms.
QUESTION 6: TRANSMISSION PLANNING Do stakeholders agree that access reform and the Integrated System Plan should be integrated? If so, do stakeholders agree with the Commission's assessment about how this could be achieved?	The role of AEMO's ISP and future transmission planning will depend heavily on the design of the proposed hedges, including duration, resolution and pricing methodology. The AEMC should engage with TNSPs and AEMO on what level of pricing information could be confidently developed and forecast, and how the various ISP scenarios would be fed into pricing decisions. We note that AEMO's historical forecasting through the ISP/NTNDP has rarely matched reality, and AEMO always underestimates the pace of change. While this would also apply to RIT-Ts, individual generation investment decisions will become directly exposed to AEMO's ISP forecasts (e.g., through the pricing of long-term hedges). This might have a more material impact on efficient outcomes, and the two-year delay between ISPs may not be appropriate for hedge costing.
QUESTION 7: ACCESS PRODUCTS What access products - defined by duration, location, amount and type - do generators want?	The choice of products will depend heavily on the proposed hedging design, and it is therefore difficult to provide material feedback at this time. In general: • **Location.** The required resolution of products (e.g., at how many nodes, etc.) will depend on how residues are allocated and how participants without hedges are treated. AEMC should ensure that any inter-regional products interact smoothly with the existing Settlement Residue Auctions. • **Amount**. The risks and issues identified under the previous OFA remain current. Care needs to be taken to minimise the complexity of transactions, promote liquidity and efficient pricing, and reduce the risk of gaming. This is most critical around any long-term allocation of transmission rights. • **Duration.** Longer-term contracts may increase certainty for new generators but will increase the risk of inefficient pricing, particularly when new capacity is required, which could lock generators out of the market. • **Type.** The AEMC's analysis seems reasonable; requiring holders to pay out on contracts seems inconsistent with the intent of the scheme.
QUESTION 8: PRODUCT PROCUREMENT	Auctions for hedges are appropriate where there is sufficient liquidity and/or the opportunity for price discovery and repeated auctions over time. Auctions are likely to be appropriate for short-term hedge products for the established network. Effectiveness will also depend on how many products are offered (or whether

Do stakeholders agree that access products should be purchased via an auction?	access is provided on a unit base through the solving of transmission constraint equations). As noted by the AEMC, if long-dated (e.g., 10 year) products are to be allocated, there is a risk that potential buyers will not be entering the market at the same time and pricing will not reflect the true value. If new network build is required, then pricing will presumably be dominated by the underlying cost of build.
QUESTION 9: PRODUCT PRICING Do stakeholders agree that a fair value approach to pricing may be beneficial?	Pricing of access is one of the most challenging aspects of the proposed reforms, and requires a significantly expanded consultation process – ideally before the Draft Report is released. The LRIC method is *in theory* appropriate for assigning costs to transmission, ensuring that generators do not pay more than the *additional* costs they incur on the system above what would have to have been spent to meet load under a counterfactual scenario. However, it is highly sensitive to modelling inputs (as noted by AEMC during the OFA review). Fair value provides an alternative metric – an estimate of the amount a generator should be willing to pay for a hedge based on a forecast of future prices. When it is greater than the cost, it would seem inappropriate to charge generators more. Conversely, if the fair value is less, how would the gap be funded? Different technologies would also likely have different “fair values” for hedges. For example, a solar farm may not place any value on local congestion when the sun is down. Effectively, hedges would become more speculative products than physical hedges. We note that given the uncertainties in forecasting, and noting that consumers already pay for the network, it may be appropriate to give generators the “benefit of the doubt” and use the lowest of the two forecasts.
QUESTION 10 Do stakeholders agree that an operating incentive scheme on TNSPs is required?	Infigen supports strong incentives on TNSPs to deliver value commensurate with the cost of hedges. This issue was explored thoroughly throughout the OFA process. If the reforms are to deliver value, then the purchase of a transmission hedge (particularly for a new generator) needs to provide a high degree of certainty to generators. For example, if a TNSP is required to build new transmission to supply then the risk should be on the TNSP to deliver that capacity on time and the quantity of hedge should not be scaled down due to (for example) project delays.
Questions 11-13	Responded to in Section 2

5. CONCLUSION

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

Yours sincerely

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