Transmission access reform (COGATI) review – technical working group #13

25 September 2020

The thirteenth technical working group meeting was held by videoconference on 25 September 2020.

The technical working group was formed by the Australian Energy Market Commission (AEMC) to provide advice and input into the progression of the transmission access reform (EPR0073).

All enquiries on this project should be addressed to Daniela Moraes on (02) 8296 0607 or Ben Davis on (02) 8296 7851.

The attendees of the meeting are listed below.

Member	Organisation
Andrew Kingsmill	TransGrid
Andrew Richards	Energy Users Association Australia (EUAA)
Arista Kontos	Australian Energy Regulator (AER)
Ben Skinner	Australian Energy Council
Bill Jackson	ElectraNet
Con Van Kemenade	ENEL Green Power
Dan Mascarenhas	AGL
Dr Darryl Biggar	Australian Energy Regulator (AER)
Dean Gannaway	Aurizon
Gloria Chan	Clean Energy Finance Corporation (CEFC)
Henry Gorniak	CS Energy
Jack San	AusNet services
Jess Hunt	ESB
Jevon Carding	Lighthouse Infrastructure
Jill Cainey	Energy Networks Australia (ENA)
Joel Gilmore	Infigen
Jon Sibley	ARENA
Kirsten Hall	Australian Energy Market Operator (AEMO)
Lawrence Irlam	EnergyAustralia
Libby Hawker	ERM Power
Lillian Patterson	Clean Energy Council (CEC)
Marilyne Crestias	Clean Energy Investor Group (CEIG)
Matthew Dickie	RWE
Michael Connarty	UPC Renewables
Natalie Thompson	The Australian Financial Markets Association
Panos Priftakis	Snowy Hydro
Peter Nesbitt	Hydro Tasmania
Rob Koh	Morgan Stanley
Robert Pane	Intergen

Ron Logan	ERM Power
Rimu Nelson	Cleanco
Sarah-Jane Derby	Origin Energy
Stephanie Bashir	Representing Tilt Renewables
Steven Nethery	Goldwind Australia
Tim Astley	TasNetworks
Tom Geiser	Neoen
Verity Watson	Energy Networks Australia (ENA)

The AEMC's project team attended and is listed below.

Name	Position
Victoria Mollard	Executive General Manager – Security & Reliability
Ben Davis	Director – Retail and Wholesale Markets
Orrie Johan	Adviser – Transmission and Distribution Networks
Daniela Moraes	Senior Adviser – Retail and Wholesale Markets
Russell Pendlebury	Senior Economist
James Tyrell	Senior Adviser – Transmission and Distribution Networks
Ella Pybus	Consultant – Cambridge Economic Policy Associates
Tom Walker	Senior Economist
Jessica Scranton	Senior Lawyer
Tom Meares	Graduate Adviser
Peter Thomas	Digital Communications Manager

At the start of the meeting, the 'competition health warning' was read out, and copies of the protocol (attached) were sent out to each member of the working group in advance of the meeting.

After an introduction and recap to the project, the meeting focussed on three areas:

1) The full design proposal for locational marginal pricing (LMP).
2) The full design proposal for financial transmission rights (FTRs).
3) The full design proposal for transitional arrangements.

Introduction

The AEMC introduced participants and mentioned that the interim report of updated design features had been recently released. The project team outlined that the purpose of the day's discussion would be to focus on the contents of the report and the reform design, and not the modelling conducted and the simplified model developed by NERA Economic Consulting, which was subject to two recent public forums in September.

The project team provided a recap of the core concepts of the reforms, namely LMP and FTRs. The project team discussed the purpose of these two features, and provided a broad outline of how they work.

Specific design decisions – locational marginal pricing

- The project team described the five key decisions relating to locational marginal prices. These are:
  - That scheduled and semi-scheduled market participants will face their LMP, as opposed to the regional price.
  - That non-scheduled market participants will continue to face the regional price.

- The regional price will change from being the LMP at the regional reference node (a pre-defined node on the network), to the volume weighted average price of all LMPs in a region.
- That LMPs should reflect dynamic marginal losses, as opposed to the current annual, static marginal loss factors.
- That a decision on applying a mitigation mechanism for inefficiently high prices will be taken through the remainder of the year, pending further analysis of extreme pricing events.

- Stakeholder questions and comments on locational marginal pricing design proposals (and responses from the project team) included:
    - Some participants inquired about the separation of congestion and losses components in LMPs. The project team explained that an LMP represents the marginal cost of supplying an extra unit of load at a particular location. The mathematically equivalent definition is that an LMP at a given location is the sum of the LMP at a given location on the network (sometimes called a "slack node" in overseas terminology), plus or minus the marginal effects of congestion and losses. This is linear, and therefore it is possible to separate out the congestion component and the loss component of an LMP.
    - Some participants asked if multiple VWAPs per region were being considered. The project team stated that they this has not been explicitly considered so far, but that it was an interesting idea – and encouraged stakeholders to include thoughts on this in their submissions. The project team continued that having one VWAP (i.e. regional price) per region would promote liquidity in the contract market and settlement. Therefore, moving to multiple VWAPs in a region may negatively impact contract market liquidity, however, it is an interesting question as to whether there should be one VWAP per region.
    - Participants queried that non-scheduled generation can add to congestion, and so wondered why these participants do not face the LMP? The project team responded that this is a good point – and again stakeholders should feel free to put this in their submissions.
    - Participants asked whether the AEMC had quantified the cost impact on contracts of the reform. The project team responded that they have provided high level cost estimates for changes in contracts in the given timeframes, with the detail set out in the interim report. We are interested in any stakeholder feedback on these estimates. It was noted that, given the implementation timeframe proposed (in the order of four years), it is unlikely that any existing contracts will be impacted, except for PPAs which are typically longer in duration. The project team stated that it will be engaging with participants to discuss the transitional costs in more detail over the coming months.
    - Participants inquired about data from the NERA modelling. The project team stated that it is currently working through these requests and will respond in due course.
    - Participants inquired about the impact of switching to dynamic losses on businesses. First, the issue of contract market liquidity was raised, suggesting that the change will lead to an increase in the cost of capital. Furthermore, it was suggested that if there is a volatility of losses at a given location of 15%, then generators may sell less contracts, putting upward pressure on contract pricings. Finally, it was raised that dynamic losses could have an impact on the adequacy of settlement residue. The project team responded that the proposal for the design on 'day 1' is for no FTRs to hedge the loss components of LMPs; however, this may come later and we are interested in stakeholder views on this point.
    - Participants inquired as to whether small generator aggregators (SGAs) would face LMPs, and if so, what LMP. The project team stated that given these parties are

scheduled they would face an LMP; however, we will work with AEMO to establish what the appropriate LMP would be.

Specific design decisions – financial transmission rights

- The project team described the 12 key decisions relating to financial transmission rights. They are:
  - That both continuous and “time of use” rights will be available.
    - Continuous rights will pay out at all times.
    - Time of use rights will pay out at specific hours of the day
  - That FTRs will be backed primarily by the settlement residue, with the auction revenue from the sale of FTRs being used to back FTRs in periods where settlement residue is inadequate. After these funds have been used completely, FTRs payments will be scaled back.
  - That AEMO will operate and manage the FTRs, with inputs from TNSPs about network capacity.
  - That AEMO will have a register of the amount of FTRs sold at each auction, as well as the purchaser and the clearing price.
  - That there will be no specific market power mitigation mechanism put in place for the FTR market.
  - That FTRs would, at least initially, only be option instruments, meaning that they will only pay out on a positive price difference for the holder, and will not require payment if the price difference is negative for the holder.
  - That small quantities of FTRs should be available up to 10 years in advance, and that FTRs will be sold in three-month tranches.
  - That both physical and non-physical market participants would be able to participate in the FTR auctions.
  - That there would be no reserve price set for the FTR auctions.
  - That there would be a reduction in the number of combinations of FTRs available. This would be achieved by limiting the locations between which FTRs are available. The nodes between which FTRs would be available will be defined by the prevalence of congestion on the transmission network.
  - That the AER adjust STIPS to be based on the cost of congestion, rather than on the instances of material congestion.
  - FTRs would not hedge price differences that arise due to marginal losses.

- Stakeholder questions and comments on financial transmission rights design proposals (and responses from the project team) included:
  - Participants sought some clarification about time of use FTRs. The project team stated that time of use FTRs mean that in practice you sell less continuous FTRs at each auction, as there is a direct trade-off between the number of continuous and time of use FTRs at each auction. The system operator doesn’t decide what the make up between continuous and time of use FTRs are sold, but rather the bids and offers (i.e. the demand from participants) made at the auction determine the proportion of products that are sold.
  - Participants inquired about the settlement residue and auction revenue being exhausted. The project team responded that if the amount of FTRs sold is consistent with the capacity of the network then the FTRs will be revenue adequate, regardless of where the congestion takes place on the network. Therefore, the effects of congestion and network outages are different.
  - In response to this, participants asked if the project team had conducted any modelling on this issue, for example by modelling what would have happened to issued FTRs if there was a large outage on the network. The project team responded that the issue of FTR firmness is covered in the appendix to the NERA report. We have also looked at this internationally, and how often FTRs have had to

be scaled back as a result of unforeseen outages, is relatively rare. The project team noted that in New Zealand they aim for scaling capacity back in 1 in 12 months but in practise this scaling back has been much rarer.

  - Participants suggested that given the dynamic nature of flows on the network, there would be significant fluctuation in the cashflow of FTR payments, which would impact on a TNSP's business and financing. The project team noted that this was helpful feedback that it would be great to set out in submissions, but there was likely a way of managing this to avoid this outcome.
  - Participants raised concerns about speculators in the FTR auction pricing small participants out of the market. The project team responded that allowing financial players in the market will promote liquidity – increasing the chances that FTRs will be available, including on the secondary market. It was also noted including financial participants does not necessarily result in nefarious behaviour. Without non-physical participants, there will be a greater concern of FTRs being sold for below fair value, and as a consequence, FTRs being less firm than would be the case with non-physical participants taking part in the auction.
  - Participants inquired as to which transmission projects would be taken into account when selling FTRs for future periods. The project team stated that priority and committed projects from the ISP will be included, and that projects need to have some notion of commitment to be realistically considered. The project team confirmed that sales will not occur solely on the basis of the current "on the ground" transmission capacity.
  - Some participants expressed concern regarding the decision to limit FTR availability to between certain pre-defined nodes, commenting that this leads to false simplicity, and that removing granularity creates complexity. These participants stated that the limiting nodes will not necessarily increase liquidity, as FTRs released through the auction are entirely fungible given the network permits it. These participants put forward that in their view the appropriate approach is to introduce full FTR availability alongside LMP. Stakeholders were encouraged to share these views in submissions.
  - Participants also asked how, if this design decision was adopted, the pre-defined nodes would be decided. The project team outlined that there are a number of factors that would need to be taken into account, including patterns of congestion along with other principles set out in the interim report. It was noted that we are currently undertaking some empirical studies to get a better feel for how many nodes there would need to be.
  - Participants observed that generators and loads will be facing dynamic losses, but generators will get LMP and loads will get VWAP. The project team stated that the question is whether we average all components into the VWAP, or whether we average energy and congestion components, and add specific dynamic losses for each location. Currently, the latter takes place, and the project team suggested that it might be a backwards step to lose loss signals for load. The team noted it is interested in stakeholder views on this matter.

Specific design decisions – transitional arrangements

- The project team described the two key decisions relating to transitional arrangements for the reforms. They are:
  - That transmission access reform will be co-ordinated with other ESB reforms, and so implemented approximately four years after the time that the relevant access reform rules are made.
  - That transitional FTRs will be provided for free to incumbents and committed participants. These transitional FTRs will be backed by settlement residue and will

be able to be traded. The cut-off date for those to be considered a committed participant would be the rule change determination date.

- Stakeholder questions and comments on transitional arrangements (and responses from the project team) included:
    - Participants inquired about how transitional arrangements apply to REZs. The ESB's representative noted that an options paper is currently being developed by the ESB to address these issues.
    - Participants inquired about whether the transitional FTRs will cover transmission outages, and whether there will be a shortfall fund for transitional FTRs. The project team stated that generators currently do not receive cover for being constrained off, either by outages or for other reasons. Providing FTRs that cover this would put holders in a better position than they are currently in, and that this may likely not be appropriate.

Next steps

- The project team outlined the next steps for the review process, including:
    - Industry group forums until 19 October 2020.
    - Written consultations due on both the ESB post-2025 market design consultation paper and the interim report by 19 October 2020.
    - Continued engagement regarding participant costs.
    - Ongoing bilateral consultation.