Transmission access reform (COGATI) review – technical working group #11

30 July 2020

The eleventh technical working group meeting was held by videoconference on 30 July 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 Russell Pendlebury on (02) 8296 0620 or Tom Walker on 0410 764 175.

The attendees of the meeting are listed below.

Member	Organisation
Andrew Kingsmill	TransGrid
Angus Holcombe	Meridian Energy
Anh Mai	AusNet Services
Arista Kontos	Australian Energy Regulator (AER)
Ben Skinner	Australian Energy Council
Bill Jackson	ElectraNet
Dan Mascarenhas	AGL
Dr Darryl Biggar	Australian Energy Regulator (AER)
David Scott	Australian Energy Market Operator (AEMO)
Dean Gannaway	Aurizon
Donovan Marsh	Energy Security Board
Gloria Chan	Clean Energy Finance Corporation (CEFC)
Henry Gorniak	CS Energy
Jevon Carding	Lighthouse Infrastructure
Jill Cainey	Energy Networks Australia (ENA)
Joel Gilmore	Infigen
Kirsten Hall	Australian Energy Market Operator (AEMO)
Lawrence Irlam	EnergyAustralia
Lillian Patterson	Clean Energy Council (CEC)
Matthew Dickie	RWE
Michael Connarty	UPC Renewables
Natalie Thompson	The Australian Financial Markets Association
Nishana Perera	Australian Energy Regulator (AER)
Nabil Chemali	Flow Power
Panos Priftakis	Snowy Hydro
Peter Nesbitt	Hydro Tasmania
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
Verity Watson	Energy Networks Australia (ENA)
Will Taylor	NERA Economic Consulting

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

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

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 technical working group (TWG) in advance of the meeting.

Introduction

- The project team outlined that the purpose of this session was to discuss market power mitigation, in relation to:
  - how / whether the introduction of LMP may change the way that local market power is exercised and how material it is;
  - given the above, the potential need for mitigation; and
  - how the introduction of FTRs may impact both the exercise of local market power in the NEM and have a bearing on the exercise of market power in the market for FTRs.
- The project team explained that our focus is on understanding whether additional market power mitigation measures will be necessary alongside the implementation of transmission access reform, in relation to both LMP and FTRs. It was also noted that the project team are undertaking empirical analysis to test some of the above propositions.

What is local market power

- The project team provided an explanation of local market power, which involves:
  - Binding constraints breaking the network up into "sub-markets". Generators within these sub-markets can have local market power.
  - A common example of this is a "load-pocket", where a constrained area has a single or small number of generators alongside load, with constraints limiting the amount of electricity that can be imported.
  - The situation is more complex in a meshed network, as one route to a load pocket may be constrained, while alternative routes may be unconstrained.
  - Geographically defining a local "market" for the purpose of market power analysis in electricity is potentially difficult given the meshed nature of transmission networks, particularly when considering the impacts of locational marginal pricing.
  - However, the project team have adopted a working definition for market power which is that a generator can be considered to have localized market power if it

  - alleviates constraints. This means that we can determine instances of market power in relation to constraints on the network. Markets do not have to be defined geographically as a result.
  - LMPs are the marginal cost of meeting demand at a regional reference node (including congestion).
    - A generator with a positive participation factor is contributing to a constraint and therefore the local price it obtains is lower than the price at the regional reference node.
    - However, a generator with a negative participation factor would alleviate a constraint if it dispatches. As a result, by economically withholding from dispatch, this generator could theoretically increase the marginal value of the constraint and therefore increase its LMP.
- Stakeholder questions and comments on the definition of market power (and responses from the project team) included:
  - One stakeholder asked whether the transmission access reforms would actually change market power in the NEM – for example, it was queried whether there are many load pocket examples in the NEM. The project team responded that while we do not see a change in the degree of market power or instances of market power, there *may* be a change in how market power in these instances is exploited, and this is what we are looking to test with stakeholders, and if we decide this is material, then address..
  - The project team pointed to quantitative work currently underway to determine the number of instances of localised market power across the network, and the likely impact of these instances, without any additional mitigation measures.

LMPs and the exercise of local market power

- The project team noted that the existing market design has features that limit the negative effects of local market power. In particular, the prices that generators receive are regulated to equal either:
  - The locational marginal price at the regional reference node (ie, the regional reference price), which is in turn capped at the market price cap or
  - The 90th percentile price, over the preceding 12 months, if the generator is directed on by AEMO.
- The team suggested that these features limit the ability of generators to use local market power to influence the price, but they are also blunt mechanisms – they mitigate regardless of the circumstances in each case, and they mitigate to the regional reference price (RRP).
- The project team noted that the introduction of LMP would remove this regulation of current prices in instances of local market power, given parties would now receive their locational marginal price.
- Generators with local market power may have more incentive to withhold capacity in order to influence their LMP as the LMP is now the price that they would receive. Their ability to want to do this would be influenced by other factors, including their contract position – so it is unclear how material this may be.
- Under the current arrangements:
  - An individual generator required to prohibit localised load shedding can bid unavailable, receive the 90th percentile price or exploit market power in network service agreements.
  - A small number of generators that are able to alleviate a binding constraint do not have an incentive to bid uncompetitively in order to maximise the marginal value of that constraint as they do not receive their LMP.
- Under the new LMP arrangements (absent of further market power mitigation):
  - An individual generator required to prohibit localised load shedding can bid high, potentially sending their LMP to the market price cap.
  - A small number of generators that are able to alleviate a binding constraint can bid high, potentially sending their LMP towards the market price cap, although they will be restrained by the competition between the generators that can relieve the constraint.

- Stakeholder questions and comments on LMP and the exercise of market power (and responses from the project team) included:
  - Some stakeholders considered that barriers to entry are decreasing over time and easier entry should act as a constraint to prevent enduing localised market power. In relation to this point, one stakeholder queried whether allocating transitional FTRs to existing participants would increase the risks for new entrants coming into the market.
  - Stakeholders also noted that some market participants with a positive contribution factor could also have market power. They could drag the price down and then collect money from their FTRs. The project team agreed to consider this further.
  - Stakeholders also clarified a number of points that are relevant to how the 90th percentile pricing works, but recognized that these are not material to the analysis.
  - Some stakeholders queried whether the transmission access reform would lead to any market power changes compared to the current framework. The project team outlined that under the existing market structure a generators local price, or shadow local price, does not impact settlement at the RRN, but if locational marginal pricing was introduced, the generator instead may have the incentive to bid up their local price, as this is the price they would receive for their energy. If this was to occur, this could have an impact on settlement residues available to back FTRs and consequently the residue available to reduce consumer TUOS.
  - One stakeholder queried what the project team's current position on whether or not there is localized market power is. The project team noted that it is a proposition we are looking to test – hence discussing with the technical working group. In addition, quantitative analysis is under way in order to help determine the materiality of any problem. It is still an option to have no additional mitigation mechanism and letting the investment responses to high prices manage the issue of market power in the instances that it occurs.
- The project team described the methodology for the empirical analysis that it is currently conducting, which involves analysing historical instances of dispatch where generators have market power over binding transmission constraints.

Mitigating market power

- The project team noted that depending on how regular and material the instances of localised market power are, both the decision on whether to mitigate and if so, the mitigation method introduce a trade-off between:
  - the risk of inhibiting market participants from recovering the costs of their investments (which may in turn deter future efficient investments), and
  - protecting consumers from high or volatile prices.
- Various mitigation options were outlined for dealing with localised market power, including:
  - Unmitigated price signals –not directly mitigating against market power but instead allowing high prices that may arise to provide signals for new investment, which would in turn address market power concerns.
  - Replicate the status quo –capping the LMPs at the RRP and provide the 90th percentile price to generators that bid unavailable.
  - Ex post mitigation –investigating abuses of market power after the fact and retroactively changing outcomes.
  - Ex ante mitigation –identifying and mitigating generators with the potential to exercise local market power before dispatch.
- The pros and cons of each of these methods was summarised by the project team:
  - Unmitigated price signals
    - Pros: It may limit the amount of intervention that a regulator/operator has in the market.
    - Cons: It may increase the risks of inefficient outcomes due to the exercise of market power, such as high prices for scheduled load, higher average prices for load, as well as potential revenue inadequacy if RRP is retained (instead of volume-weighted average pricing (VWAP)).

- Replicate the status quo
  - Pros: It is likely to be familiar to market participants.
  - Cons: This method would regulate prices in all instances where the LMP exceeds the RRP and therefore may lead to significant over-mitigation. It could also remove efficient price signals at the heart of the reform.
- Ex post mitigation
  - Pros: It is likely to limit the amount of excessive intervention in the market if used sparingly.
  - Cons: It introduces discretion to the mitigation process, which may cause uncertainty for stakeholders. It also may be resource intensive.
- Ex ante mitigation
  - Pros: It could potentially be built into dispatch and occur automatically, which may help promote certainty of outcomes for stakeholders
  - Cons: If setup incorrectly it may run the risk of consistent over and under mitigation.

- The project team outlined three options for ex ante mitigation:
  - Pivotal supplier test (PST) - this is a structural measure of market power, which tests the extent to which a generator or group of generators is necessary to meet load in a given dispatch interval. The test is performed on the generation capacity available to help alleviate a binding constraint.
  - HHI based test – this is a structural measure, which tests the concentration of the supply of generators which can alleviate a given constraint. This test is also performed on the generation capacity available to help alleviate a binding constraint.
  - Conduct and Impact Test - this is a behavioural measure, which tests the impact that non-competitive bidding would have on prices. This test is performed on a group of generators in a pre-defined geographic area.
- Stakeholder questions and comments on mitigating market power (and responses from the project team) included:
  - One stakeholder expressed the view that there are good reasons why localised market power should be less of a concern in the future. They suggested that market power is already declining and will be much less of a constraint going forward, and so an answer may be to let instances of market power happen, providing signals for new generation investment. This is because of the technological changes going on in the NEM right now – renewables and batteries can be planted anywhere and are smaller than other forms of generation, making it easy to plant them wherever market power would be found. This includes small increments of new generation. It should also be noted that the lead times for new generation investment in renewables and batteries are also shorter. This suggests there is no need for a mitigation measure.
  - One stakeholder asked how the proposal for an ex ante mitigation mechanism would interact with other market power measures e.g. the big stick legislation. The project team noted that there are a a number of measures to deal with broader competition / market power issues in the NEM including the measure suggested, as well as the CCA, and other provisions in the rules. It was also noted that these measures are typically ex post, whereas the project team's current preference is for an ex ante approach.

Market Power and FTRs

- The project team noted that it has heard from some stakeholders that FTRs could potentially influence incentives to exercise local market power over LMPs. In our March design paper we set out that:
  - FTRs are designed as options that pay out on the positive price difference between a particular nodal price and the RRP.
  - FTRs would be available in both directions, so that they could pay out on (RRP-LMP) as well as (LMP-RRP).

    - A generator that owns an FTR that pays out on (LMP-RRP) may have an extra incentive to maximise their LMP in order to maximise the FTR payout
    - This concern is not unique to FTRs. Any contract struck against a price influences the contract holder's incentives to exercise market power over that price.
    - Therefore, we do not consider that this problem is likely to be material.
- However, if it was deemed to be material, then this could be addressed by:
    - Employing a market power mitigation mechanism as described above, or
    - By prohibiting generators from buying an FTR "to" their local node, although this may impact risk management operations (i.e. one of the purposes of introducing FTRs).
- The project team then noted that a lack of competition in the FTR market could result in FTRs being regularly sold for considerably less than fair value. The team suggested that:
    - The inclusion of non-physical participants in the FTR auction would increase competition in the FTR market, decreasing the ability for participants to exercise market power.
    - Competition law prohibitions under the Competition and Consumer Act 2010 would extend to conduct in the market that would be created for FTRs.
    - Additional measures to limit the impact of market power in relation to FTRs include involving the AER and the ACCC in the monitoring of these markets.
    - It is proposed under the reform design that there would be a register of the sale and ownership of FTRs.
    - The project team suggested that concerns that non-physical players might hoard FTRs or restrict access to FTRs seem unfounded. Where a physical participant offers fair value for the instrument, it is in the interest of the non-physical player to trade: they cannot gain a competitive advantage in an up- or downstream market from hoarding the instruments.
- Stakeholder questions and comments on market power and FTRs (and responses from the project team) included:
    - One stakeholder asked whether the market power test would apply to any node or just to the RRN. The project team responded that these tests would not be applied to a particular node, instead they would be applied to a binding constraint, consistent with the definition of 'market' set out above.
    - One stakeholder asked whether FTRs would dampen the incentive to exercise market power, because if the generators LMP is lower then the FTR payout as a whole will be higher. The project team responded that in this example, this is the case, if the generator purchases an FTR option paying out on the difference between the RRN and the LMP. However, there is a concern if the generator purchases a FTR in the other direction, going from the RRN to the LMP.
    - Another stakeholder stated that there hasn't been as much focus on generators being able to buy options on the opposite side (from the RRP to their LMP) and asked whether these could be purchased too. The project team agreed with this, and noted that while options could be bought in either direction (from the LMP to the RRP or from the RRP to the LMP), this discussion has been focused on the former because that is likely to be more useful to the majority of participants.
    - One stakeholder said that there has been a recent increase in stability constraints, which could lead to more constrained on generation. The project team responded that we will look further into this but it should be noted that these occurrences do not necessarily need to be mitigated if there is competition behind the constraints.
    - Another stakeholder recommended considering the implications of transitional allocations for market power and stated that it is important not to protect stranded assets. They wondered whether transitional FTR allocations could lead to generators exercising market power and preventing new entrants from setting up in congested areas. One stakeholder added the comment that the solution to this problem is clear, make transitional FTR allocations entirely tradeable.

Next steps

- There will be another TWG meeting on the overall model design. This is planned for September.
- There are public forums planned for:
    - NERA modelling results in September
    - A simplified model of the reforms in action for September.
- Written consultation:
    - The ESB post-2025 market design consultation paper will feature a section on transmission access reform, as it is one of the MDIs. It will be published in August.
    - An updated transmission access reform technical specifications document consultation report will be published in late August.