AEMC

REVIEW

Australian Energy Market Commission

DISCUSSION PAPER

COORDINATION OF GENERATION AND TRANSMISSION INFRASTRUCTURE PROPOSED ACCESS MODEL

14 OCTOBER 2019

INQUIRIES

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ABOUT THE AEMC

The AEMC reports to the Council of Australian Governments (COAG) through the COAG Energy Council. We have two functions. We make and amend the national electricity, gas and energy retail rules and conduct independent reviews for the COAG Energy Council.

SUMMARY

1 In 2016, the Council of Australian Governments (COAG) Energy Council asked the Australian Energy Market Commission to implement a biennial reporting regime on *when* the transmission regulatory frameworks will need to change, and, if so, *what* they will need to change to.

2 The Commission is of the view that change is needed now, so that our transmission regulatory frameworks evolve to be consistent with the transition in the characteristics of the generation mix joining the national electricity market (NEM). Transmission access reform is vital in order for the NEM to effectively manage the current transition underway in generation technologies, whatever this future may look like.

3 The current review has two key focusses:

- developing the specification of the **proposed access model**, which implements dynamic regional pricing and financial transmission rights
- facilitating **renewable energy zones** (REZs), which are a useful first step on the path to holistic access reform and can be implemented earlier.

4 This paper sets out the proposed access model. The proposed model is set out in response to stakeholder feedback that a detailed design - a 'working' model for reform - would be valuable and allow for feedback ahead of drafting rule changes necessary for the reform. The blueprint for our design is summarised at the end of this section. This detail will help stakeholders to consider and work through the potential impacts that the model may have on their operational and investment decisions.

5 We welcome stakeholder feedback on our proposals, including whether there are different ways the parameters could be designed, or other matters we need to take into consideration.

Access reform will coordinate generation and transmission investment

6 The electricity sector transition that is currently under way is changing the dynamics of the power system. Traditional thermal plants are closing, and more renewable and asynchronous generators are coming to the power system. The introduction of 5 minute settlement reforms will incentivise more flexible types of generation technologies over the coming years.

7 Generation roughly equal to the current size of the NEM (50 GW) is foreshadowed for connection to the grid over the next 10 years. The national electricity market will replace most of its current generation stock by 2040. Unlike the existing power system, the system of the future is likely to be characterised by a large number of relatively small and geographically dispersed generators. Further, these generators are unlikely to be located where there is substantial existing transmission to serve them, and is instead being connected in sunny or windy areas at the edges of the grid, where the network is less strong. In addition, these new types of generation can in general be built more quickly than transmission infrastructure required to serve them.

8 In addition, the networks across the NEM are becoming more meshed and interconnected, with this being combined with increased inter-regional trade and sharing of reserves between jurisdictions.

9 These trends will continue. The Australian Energy Market Operator's (AEMO's) Integrated System Plan (ISP) in the 'neutral with storage' modelling scenario shows that by 2030 over 6,000 MW of existing generation is expected to close and be replaced by approximately 22,000 MW of renewable generation and 6,000 MW of storage. By 2040, the amount of expected closure increases to approximately 16,000 MW, which is projected to be replaced by 50,000 MW of renewable generation and 20,000 MW of storage. If a faster and bigger transformation occurs, then these values will increase and occur sooner.

10 Substantial and timely transmission infrastructure is therefore likely to be required.

11 These changes mean that there is a need to have a better way of co-ordinating generation and transmission investment decisions in order to better facilitate the transition that is occurring.

12 The existing transmission access regime, where all generation and load is settled on a region-wide price for its physical output or consumption (net of losses), was a central design choice in establishing the NEM. This choice reflected a compromise between reflecting the underlying realities of the system and the benefits of a simple unified price model, and was fit-for-purpose in an environment of relatively low levels of generation and transmission investment, where the transmission risks faced by generators are relatively predictable and stable.

13 However, this design choice is no longer appropriate given the emerging environment, and a number of consequences of the original design have become significant and more challenging to manage.

14 Due to the current **lack of locational price signals** in the transmission framework, investors have located their generation or storage assets where the network has limited or no capacity for the additional capacity to be dispatched. Under the current framework, these parties are finding it difficult to manage the risk that the existing transmission network will not be sufficient to accommodate them.

15 In light of the electricity market transition, prospective generators and storage **require greater certainty** that their assets can remain profitable even if subsequent parties connect to the network and create congestion or adverse loss effects.

16 In the current climate, it is also clear that consumers have concerns about projected costs and increased bills in order to pay for the new transmission necessary for the transition. The current wholesale pricing arrangements are sending **adverse operational incentives to generators and storage** and leading to higher wholesale prices over the longer term.

17 For example, generators are incentivised to bid unavailable in certain situations because the regional price does not reflect their marginal cost of supply. This leads to AEMO needing to give directions and results in a less **reliable, more costly power system**.

18 In addition, generators are currently incentivised to bid in at the market price floor when they

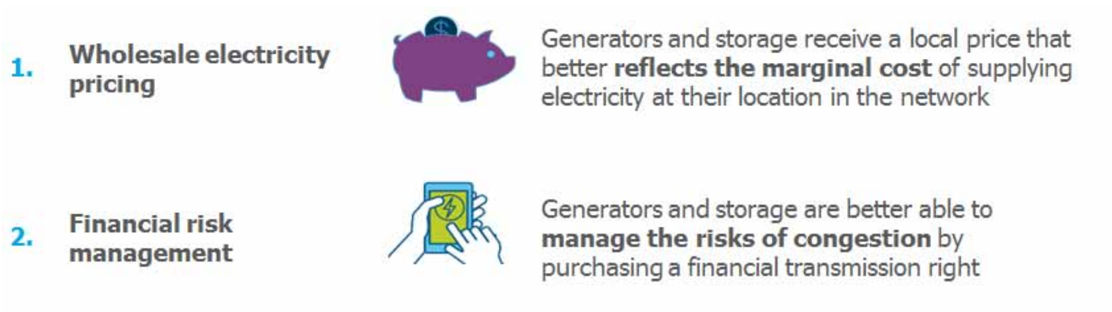
are behind a transmission constraint ('race to the floor' bidding). Race to the floor bidding means that the lowest cost available generator is not always dispatched, which can **increase the wholesale cost of electricity** over the longer term for consumers.

19 Transmission access reform is vital for the NEM to effectively evolve, transition, and co-ordinate investment resulting in least-cost wholesale outcomes for consumers. The proposed model will address the issues raised by market participants, consumer groups, and observed and foreshadowed by the ESB, AEMC and other market bodies.

Our proposal for access reform

20 The proposed model focusses on changing two inter-related aspects of the current transmission access framework.

Figure 1: Features of reform proposal



Source: AEMC

21 The model the Commission is proposing shares considerable similarities with common electricity market designs elsewhere, particularly in the US and New Zealand. The underlying rationale for the designs elsewhere are the same as those outlined above: a desire to provide appropriate, location specific price signals for generation and transmission network service providers, and the tools to allow them to manage risks.

22 However, the Commission's proposed model reflects the unique features of the NEM, including the fact that it is a relatively, long, stringy power system, as well as the fact that the formal wholesale spot market sits alongside the contract market. The wholesale market for electricity determines the prices and quantities generated and purchased every trading interval in every region of the NEM. However, the wholesale cost of electricity is not the product of these quantities and prices but is driven largely by the outcome of contracts struck between generators and retailers. The prices for electricity paid by retailers to generators in these contracts influence how generators bid into the wholesale market.

Wholesale pricing reform

23 The first element of the model relates to the wholesale electricity prices that scheduled parties, such as generators and storage are settled at.

24 Under the current framework, all market participants (generation and load) either receive or

pay a single regional reference price for each megawatt hour of electricity they dispatch or consume, regardless of where they are located within a region.

25 We are proposing to change these arrangements so that scheduled parties, such as generators and storage, receive a price (a "local price") that more accurately represents the marginal cost of supplying electricity at their location in the network (taking both congestion and losses into account).

26 Retailers and other non-scheduled market participants would continue to be settled at a common regional price for wholesale electricity, in order to support liquidity in the forward contract market.[1]

27 This change should improve **incentives for scheduled and semi-scheduled generators and storage to operate efficiently**. These parties should have greater certainty over their revenue, and should be better protected from changes due to congestion and loss factors. In turn, this should lead to a reduction in the amount of generators bidding 'unavailable'. This increased generation will be available to meet demand and so increases the security and reliability of the network.

28 The introduction of dynamic regional pricing should also eliminate race to the floor bidding by generators when the system is congested, where generators bid to the floor price in order to maximise the chance that they should be dispatched. They do this because they are unlikely to influence the price they receive, and are instead trying to maximise their dispatch through the congested system. This may be particularly important for generators who are contracted, who need to match the volume they physically deliver to the market with their contractual positions to avoid payments under those contracts not being covered by income from the spot market. This is currently contributing to higher electricity costs for consumers, because the generators actually dispatched are not necessarily the lowest cost combination.

29 In addition, dynamic regional pricing facilitates **improved investment locational signals**. This is because exposure to locational marginal prices provides better information and incentives to scheduled parties, such as generators and storage, on the value of locating in different parts of the network.

30 **Better locational operational and investment decisions** should, in turn, result in a more efficient transmission network over the longer term, ultimately lowering costs for consumers.

31 Finally, we consider that dynamic regional pricing improves the **efficiency of dispatch** by more accurately measuring the effects of losses and constraints within the system. Introducing dynamic loss factors will help to ensure the lowest cost combination of generation is dispatched at any given time.

Financial risk management

32 The second aspect of the model aims to improve the financial risk management options for generators, storage, retailers and other market participants.

1 The key aspects of the design are summarised at the end of this section.

33 We are proposing to enable scheduled market participants exposed to their local price to better manage the existing risks of congestion and transmission losses by enabling them to purchase financial transmission rights. These products will hedge against the price differentials that arise under dynamic regional pricing, which result from congestion and losses.[2]

34 Under the current framework, we expect that market participants will increasingly find it difficult to manage the increasing volatility and unpredictability of congestion and losses that arise as a result of the transitioning power system. For example, a generator or storage device's ability to earn the regional reference price is currently totally dependent on it being dispatched. How this impacts the generator depends on its position in the contract market. Similarly, market participants are unable to control on their annual marginal loss factor changes once they have made an investment decision.

35 In contrast, under the proposed model, financial outcomes would be partially decoupled from dispatch. If a generator or storage operator had purchased a financial transmission right, then it would be paid if its locational marginal price differed from the regional price.

36 These arrangements should improve **investment certainty** for generators and storage and may **reduce their cost of capital** in the longer term. This is because generators and storage with financial transmission rights face less risk that other participants may change or undermine their expected revenue from their business case by locating nearby and causing congestion or adverse loss effects in the local transmission system.

37 This should also improve participants' willingness to offer energy contracts, improving **contract market liquidity**, both within regions, but also across regions. This will occur because parties will be able to better manage the risk of congestion. Market participants should also be able to better manage the risk of contracting for electricity with counterparties located in different regions of the NEM. This should further improve liquidity in the contract market by providing participants with a wider pool of possible counterparties, particularly as the NEM regions become more interconnected.

38 In addition, the introduction of financial transmission rights should enable **TNSPs to manage their balance sheet more effectively.** This is because the proposal will abolish the current non-firm settlement residue auction (SRA) units and replace it with inter-regional financial transmission rights that are firmer and more valuable to market customers. The money for these financial transmission rights will be paid out directly through AEMO's settlement system, so TNSPs will no longer have issues with year-to-year cashflow management.

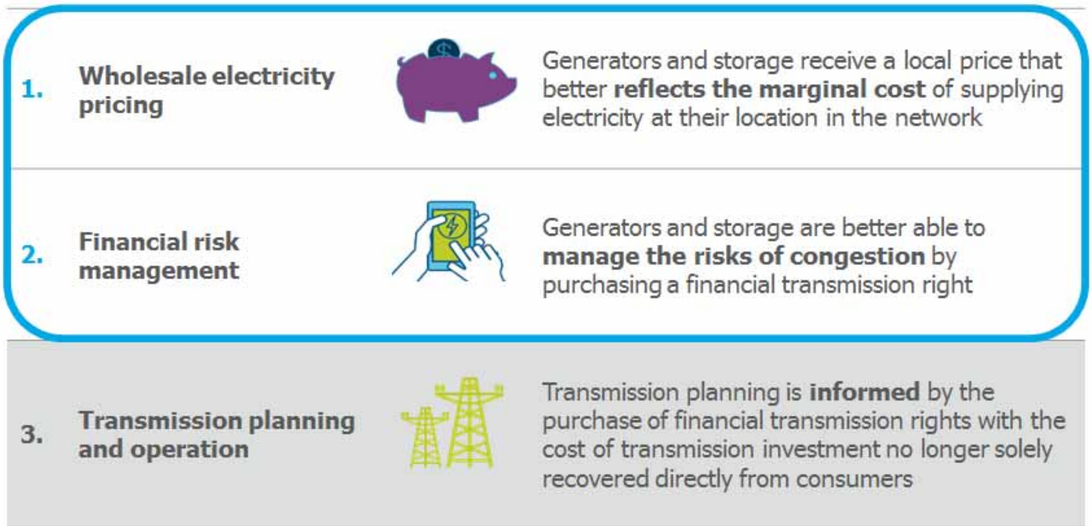
39 Finally, the introduction of financial transmission rights should **improve the operation of the transmission network**, as it will be accompanied by an enhanced operating incentive scheme for TNSPs. The enhanced incentive scheme should better align the risks that TNSPs face with those faced by market participants, by linking incentives to the wholesale price for electricity. This means the operation of the power system should be more efficient.

2 The key aspects of the design are summarised at the end of this section.

Interaction with the Actioned ISP

40 The June directions paper had proposed three pillars of reform (outlined in the Figure below). However, in response to the directions paper, many stakeholders suggested that a model with dynamic regional pricing and financial transmission rights that did not directly link to the transmission planning framework would be preferable. This has informed the Commission's focus on the first two elements of reform described above.

Figure 2: Overview of the previous model



Source: AEMC

41 Therefore, under our proposed reform model, transmission planning and investment would continue to be conducted using the current regulated process, including the ISP. Following this, an amount of financial transmission rights that takes into account the physical capacity on the network would then be available for purchase by generators, storage, retailers and other market participants.

42 To be clear, and in contrast to our earlier proposal, the amount of financial transmission rights available would be limited to the aggregate amount of transmission capacity (both committed and currently available) as determined by AEMO in conjunction with the TNSPs through the transmission planning and investment decision-making process.[3]

43 The introduction of financial transmission rights will still *indirectly* influence transmission planning and investment decisions over time. For example:

- Financial transmission right auction outcomes could reveal the level of demand from generation for access to a particular part of the transmission network. This information may be useful to inform the development of future strategic and project plans. such as the ISP and TNSP's Annual Planning Reports.

3 Rather than being determined directly by market through their financial transmission right purchasing decisions, as previously proposed.

- The framework should create a larger incentive for generators, retailers and storage to engage in future planning and investment processes. This is because the amount of financial transmission rights will directly correspond with the investment decisions made by TNSPs.
- At any given time, transmission planning will take account of the existing and committed stock of generation across the network. As the introduction of the model is expected to result in different, and more efficient, locational decisions by generation and storage assets, this in turn should result in an improved plan for transmission investment.

44 The ESB's work on actioning the ISP therefore goes hand in hand with our COGATI reforms. The ESB is expected to release draft rules on this shortly. The AEMC is working closely with the ESB to progress these reforms.

Transition and grandfathering

45 We are also concious that transitional processes will be necessary to make sure that the introduction of access reform does not create sudden changes in the market, and to provide for a learning period. Access reform will impact participants differently. Transitional arrangements - both in terms of timeframes of introduction and grandfathered rights - will be important to manage this effectively.

46 Importantly, the transition process should not unnecessarily delay or dilute the efficiency benefits that the reform model is designed to promote. This paper sets out our initial view on the transition for generators and TNSPs.

Implementation

47 Transmission access reform is needed sooner rather than later for the NEM to effectively evolve. Access reform is integrally linked with the transition and its changing generation mix, which is affecting all types of market participants.

48 We are also concious of stakeholder feedback that sufficient time is needed for the market to prepare for a reform of this nature. In this context, it is important to note that the proposed model is somewhat simpler now that financial transmission rights will no longer determine transmission investment decisions.

49 Therefore, we are still of the view that July 2022 is appropriate for implementation of dynamic regional pricing and financial transmission rights. As with any change, the implementation date of this reform will be finalised during the rule change processes[4], when detailed costing and system changes will be better known, as well as the timetable of related market reforms.

50 The issues paper recently released by the ESB notes that the current limited locational signals in transmission frameworks, as well as speed and scale of connections of new generation capacity, means investment in generation is being made where there is little or no capacity

4 These are anticipated to be lodged next year.

for it to be dispatched.[5] In considering how greater co-ordination of generation and transmission can be achieved, a spectrum of possibilities is available. The paper notes that the COGATI review will determine where on the spectrum of approaches the future market design will lie.

51 Lastly, the ESB's paper also suggests any recommendations the ESB's post 2025 project makes will be consistent with the COGATI review proposals and look to build upon the proposals. The Commission is concious of these interactions and has sought to design an access reform model that while adapting the NEM to meet the trends arising from the transition, also provides flexibility for the exploration of different future market designs. The Commission considers that the access reforms proposed in this paper are likely to be an appropriate, no regrets step that is suitable for any post 2025 design of the market.

Our approach to quantitative modelling

52 The majority of stakeholders that responded to our June directions paper suggested that some form of quantitative analysis should be undertaken on the reform proposal. However, stakeholders' objectives for this modelling varied.

53 When considering whether or not a particular change will facilitate the national electricity objective, modelling can potentially provide an important input into the assessment above and beyond any qualitative assessment that we may undertake. This paper sets out an initial plan for modelling the COGATI reform.

54 We are seeking stakeholder input on our plan to conduct quantitative modelling within the review. As identified by stakeholders, modelling can help inform specific policy design choices and weigh the potential impacts of reform, as well as provide a potentially valuable communication tool.

55 In particular, we expect that 'paper trials' of the reform will be crucial in informing specific design decisions and building understanding of the reforms.

Stakeholder consultation

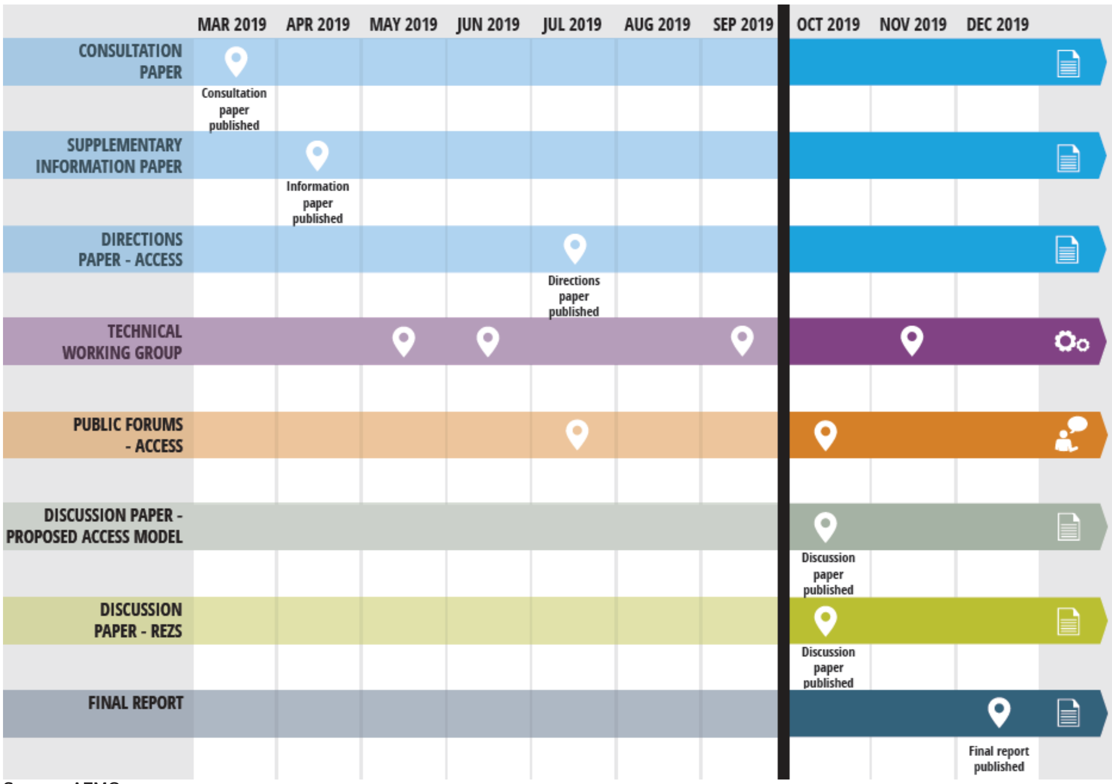
56 The Commission is holding a workshop on this reform on 18 October 2019 in Melbourne. Stakeholders should register via the Commission's website.

57 The Commission invites comments from interested parties in response to this paper by 8 November 2019. All submissions will be published on the Commission's website, subject to any claims of confidentiality.

58 We would also welcome meetings with stakeholders. Stakeholders wishing to meet with the AEMC should contact Tom Walker at tom.walker@aemc.gov.au.

5 For more information, see: http://www.coagenergycouncil.gov.au/publications/energy-security-board-%E2%80%93-converting-integrated-system-plan-action-consultation-paper

Figure 3: COGATI review indicative timeline



Source: AEMC

Summary of design specification

59 The blueprint for our design is summarised below.

Table 1: **Summary of key design features for proposed reform**

ISSUE	PROPOSED DESIGN CHOICE	COMPARISON TO CURRENT ARRANGEMENTS
What participants will face the local price? (see chapter 4)	• Large-scale generators and storage would be paid their local price - a price which reflects the cost of supply at their specific location. Local prices will differ from one another due to either: constraints arising on the transmission network, which limit the flow of electricity; and/or losses. • Retailers, and so customers, would still pay for electricity at a regional price - which is the same no matter where the customers are located in a region.	• All parties are both pay and receive the regional price.
What is the regional price? (see chapter 4)	• Ideally, the regional price would be calculated as the volume weighted average of local prices. This is a more accurate representation of what consumers should be paying because it is based on actual patterns of supply and demand.	• Parties both pay and receive the regional price - the "regional reference price". This is the marginal value cost of supply at a pre-determined location in each region (the "regional reference node").
How will participants manage the risk of congestion and losses? (see chapter 5)	• Large-scale generation and storage that are settled at the local price will be able to purchase financial transmission rights. This will protect these parties against times when there are differences between the local and regional price, due to congestion and/or losses. These rights will provide a financial payout when the prices differ from one another. • The rights would only pay out a positive amount e.g. generators would not be subject to a liability when the payout was negative. • The money for the payout arises from the difference between what large-scale generators and storage are being paid (the local price) and what load is paying (the regional price).	• Participants are limited in their ability to manage congestion or loss risks.

ISSUE	PROPOSED DESIGN CHOICE	COMPARISON TO CURRENT ARRANGEMENTS
What are the different specifications of financial transmission rights that can be purchased? (see chapter 5)	• Large-scale generators and storage can purchase financial transmission rights which pay out the price difference between a local price and any regional price; and a regional price and any other regional price. This enables parties to be protected both within a region, but also between regions. • Financial transmission rights can be purchased for either continuous payouts (i.e. the right would pay out whenever there is price separation) or within a specific time of use band.	• N/A
How long can the financial transmission rights be purchased for? (see chapter 6)	• Large-scale generators and storage would be able to purchase rights for quarterly periods, up to three to four years in advance. • Parties could purchase any combination of rights. • For example, participants could purchase a right for the immediately upcoming three-month period, or for a three-month period three years in the future.	• N/A
What will the local prices reflect, and so what risks will financial transmission rights cover? (see chapter 5)	• The local prices and financial transmission rights will encompass all constraints that are currently in AEMO's dispatch engine • The local prices and financial transmission rights will also incorporate loss factors that are calculated every five minutes.	• N/A
How can parties purchase the financial transmission rights? (see chapter 6)	• Large-scale generators and storage would bid for these financial transmission rights in an auction. • AEMO would run the auction, with input from the TNSPs being used to determine how many financial transmission rights can be sold.	• N/A

ISSUE	PROPOSED DESIGN CHOICE	COMPARISON TO CURRENT ARRANGEMENTS
	• Only large-scale generators and storage devices, retailers and other forms of physical market participants would be able to participate in the auction for some products. Other products will be able to be purchased by all types of market participants (including traders). • Parties could sell rights in a secondary market.	
How transparent would the procurement process be? (see chapter 6)	• AEMO would maintain a register of the amount of financial transmission rights sold at auction, and the sale price. • This would also include information about the current holders of financial transmission rights.	• N/A
How are issues of market power dealt with? (see chapter 4)	• The Commission does not envisage that market power will be increased as a result of these reforms. • We will be undertaking modelling on this issue. • If we do need a market power mitigation measure, then a cap on a generator's offer would be applied if it was deemed to be pivotal (ie, deemed to have market power at that specific time and location).	• There are a number of provisions in the NER that address market power (e.g. bidding in good faith rules), and the AER has a wholesale market monitoring function.

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1 INTRODUCTION

1.1 Terms of reference

The *Coordination of Generation and Transmission Investment* (COGATI) review is focussed on examining *when* the transmission frameworks will need to change, and, if so, *what* they will need to change to. This review is undertaken pursuant to a terms of reference received in 2016 from the Council of Australian Governments (COAG) Energy Council, which asked the Australian Energy Market Commission (AEMC) to implement a biennial reporting regime on these matters.[6]

The inaugural COGATI review commenced in early 2017, and concluded with its final report being published in December 2018 (inaugural COGATI report). This final report concluded that change to the transmission frameworks is needed at the present time so that our regulatory frameworks evolve to match the transition under way in the NEM.[7]

Given that the AEMC is to report biennially, the second COGATI review commenced on 1 March 2019 with the publication of a consultation paper.[8]

1.2 Purpose and scope of this review

The current review has two key focusses:

1. developing the specification of the **proposed access model**, which implements dynamic regional pricing and financial transmission rights
2. facilitating **renewable energy zones** (REZs), which are a useful first step on the path of more holistic access reform and can be a simpler, more discrete implementation than reforming the access regime.

The first focus is the subject of this paper. The second focus on renewable energy zones is the subject of the accompanying discussion paper.

The Commission will conclude the current review in December 2019 by providing the COAG Energy Council with a proposal of changes to the rules to embed and implement the proposed model. This proposal will include recommendations relating to both the access model and renewable energy zones.

The Commission is also working with the Energy Security Board (ESB) and other market bodies to report back to the COAG Energy Council in 2019 on REZ connections, access and congestion, as well as the broader work on *Actioning the ISP*.[9] The outcomes of consultation on this paper will form an input into the ESB's recommendations to the COAG Energy Council in December 2019.

6 The terms of reference were provided under section 41of the National Electricity Law (NEL) and can be found here: https://www.aemc.gov.au/sites/default/files/content/97164a7bf-49fb-9f2e-f6b996f5a96b/Reporting-on-drivers-of-change-Terms-of-Reference.PDF

7 The final report is available from the AEMC website at https://www.aemc.gov.au/sites/default/files/2018-12/Final%20report_0.pdf

8 The consultation paper is available from the AEMC website at https://www.aemc.gov.au/sites/default/files/2019-03/Consultation%20paper_0.pdf

9 See recommendation 12 of the ESB's *Integrated System Plan; Action Plan,* December 2018.

It is anticipated that the proposed changes to the rules will be submitted to the Commission to be progressed through the rule change process in early 2020. In addition to the stakeholder engagement opportunities in this review detailed below, there will be numerous opportunities for further detailed stakeholder engagement next year when the Commission assesses the changes through any submitted rule change requests.

1.3 Purpose of this paper

This paper sets out an internally consistent design for the proposed access model that would help to better facilitate the transition that is occurring the NEM. The Commission has set out the detail of this proposed model to allow for stakeholder feedback.

All elements of the proposed model are design choices, most of which require trade-offs to be made, and some of which are incompatible with other choices for different elements. We have set out a consistent and integrated set of design choices. These are described throughout.

We have set out this proposed model in response to stakeholder feedback that a detailed design would be valuable. The detail presented in this discussion paper will help stakeholders to consider and work through the potential impacts that the model may have on their operational and investment decisions.

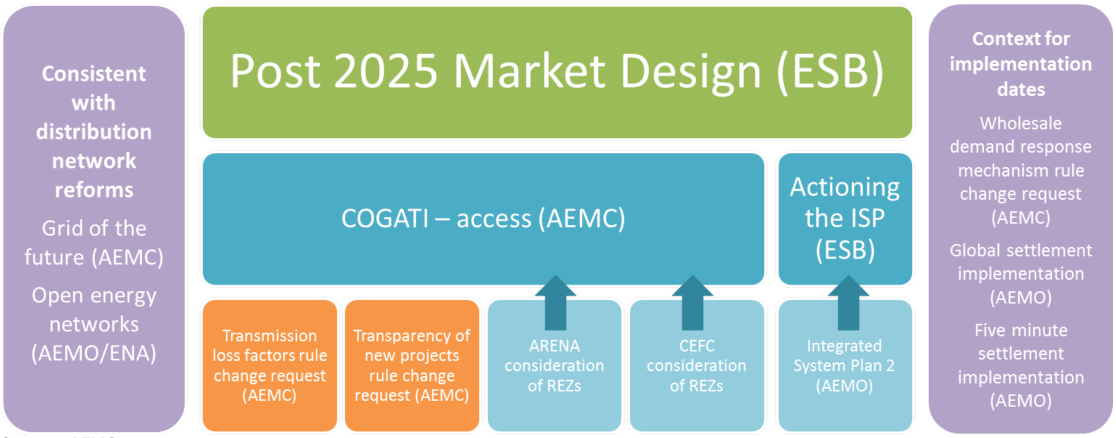
This proposed model is set out for stakeholder feedback. We welcome feedback on our proposals, including whether there are different ways in which the parameters could be designed, whether there are other parameters that we need to consider further, or other aspects we need to take into consideration.

The discussion and recommendations in this specification paper are consistent with the proposals for renewable energy zones as discussed in the accompanying COGATI renewable energy zones discussion paper.

1.4 Interaction with other key reforms under way

This review is being conducted within the context of a broader reform agenda being pursued by the market bodies and the Energy Security Board. Related projects are summarised in Figure 1.

Figure 1.1: Interaction with other key reforms



Source: AEMC

The AEMC is working closely with the above market bodies and the Energy Security Board to make sure that the various reforms under way are coordinated. Further detail on how key projects relate to each other is contained in Chapter 2.

1.5 Review timeline

The review timeline for 2019 is summarised below. The Commission has amended the project timeline in response to stakeholder feedback to the June directions paper. Many stakeholders expressed support that the access frameworks need to change now. Others expressed support for the intention of our proposed model, including that it could provide signals for efficient dispatch of generation and more efficient generator locational decisions, as well as increased certainty of access to transmission network capacity.

However, stakeholders asked for more details on how the dynamic regional pricing and financial transmission rights would operate. Some stakeholders also requested more focussed consultation on renewable energy zones and how they can be used as a transitional measure.

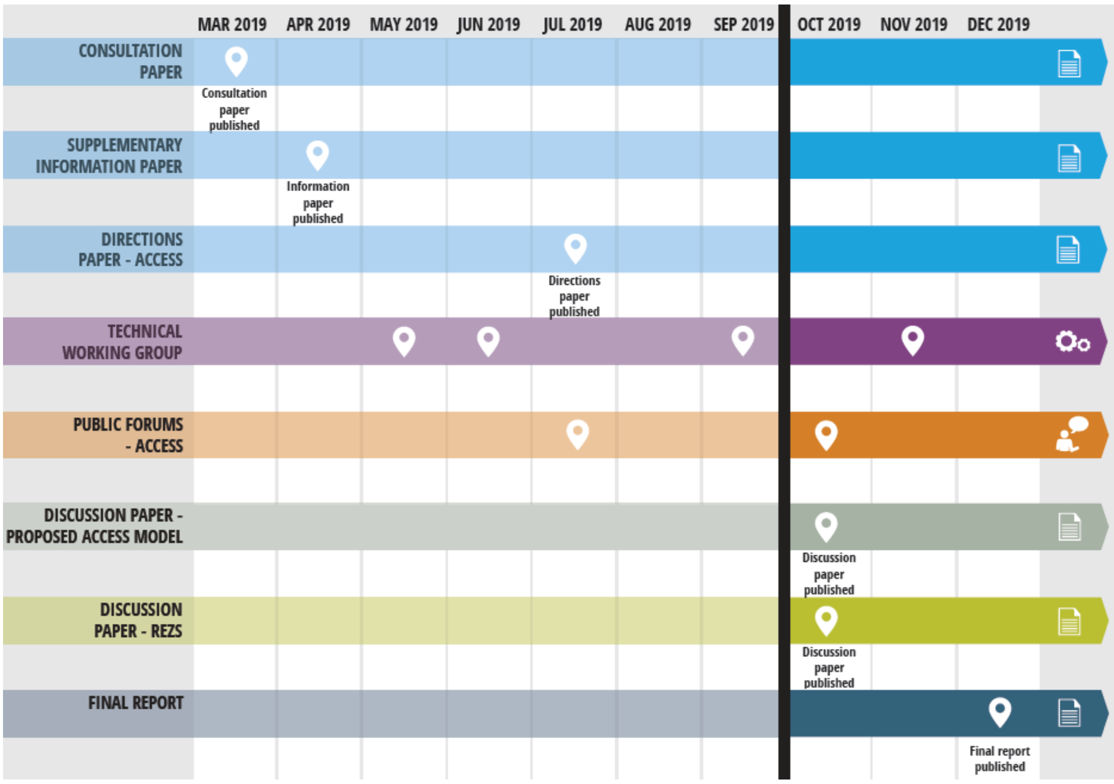
Therefore, the Commission has revised its approach in order to publish two papers:

1. this paper, which provides a specification of the proposed access reform model, introducing dynamic regional pricing and financial transmission rights
2. a separate discussion paper on renewable energy zones.

These papers will be followed by the publication of a final report in December 2019.

In addition, we have formed a technical working group for this project. The group has met three times to date, and will meet again in November 2019.

Figure 1.2: COGATI review indicative timeline



1.6 Submissions

Written submissions on this discussion paper must be lodged with the Commission by 8 November 2019 via the Commission's website, using the 'lodge a submission' function and selecting the project reference code EPR0073. The submission must be on letterhead (if submitted on behalf of an organisation), as well as signed and dated.

Where practicable, submissions should be prepared in accordance with the Commission's guidelines for making written submissions. The Commission publishes all submissions on its website, subject to a claim of confidentiality.

All enquiries on this paper should be addressed to Tom Walker at tom.walker@aemc.gov.au.

1.7 Workshop

The AEMC will hold a workshop in Melbourne on 18 October 2019 to provide an overview of the proposed model, work through examples of how the model would operate in practice, and seek stakeholder feedback. The workshop will also work through the discussion paper on renewable energy zones.

Interested participants should register for this event by visiting the AEMC website.

1.8 Structure of the report

The remainder of the paper is structured as follows:

- chapter two sets out the need for change
- chapter three provides an overview of the proposed access model
- chapter four sets out the specification for dynamic regional pricing
- chapter five has a specification for financial transmission rights
- chapter six discusses the procurement of financial transmission rights
- chapter seven provides our approach to modelling
- chapter eight discusses the transition
- chapter nine sets out our views on implementation of the reform
- appendix A sets out our assessment framework
- appendix B provides more detail on dynamic regional pricing and settlement
- appendix C sets out international experiences.

2 NEED FOR CHANGE

2.1 The changing dynamic of the power system

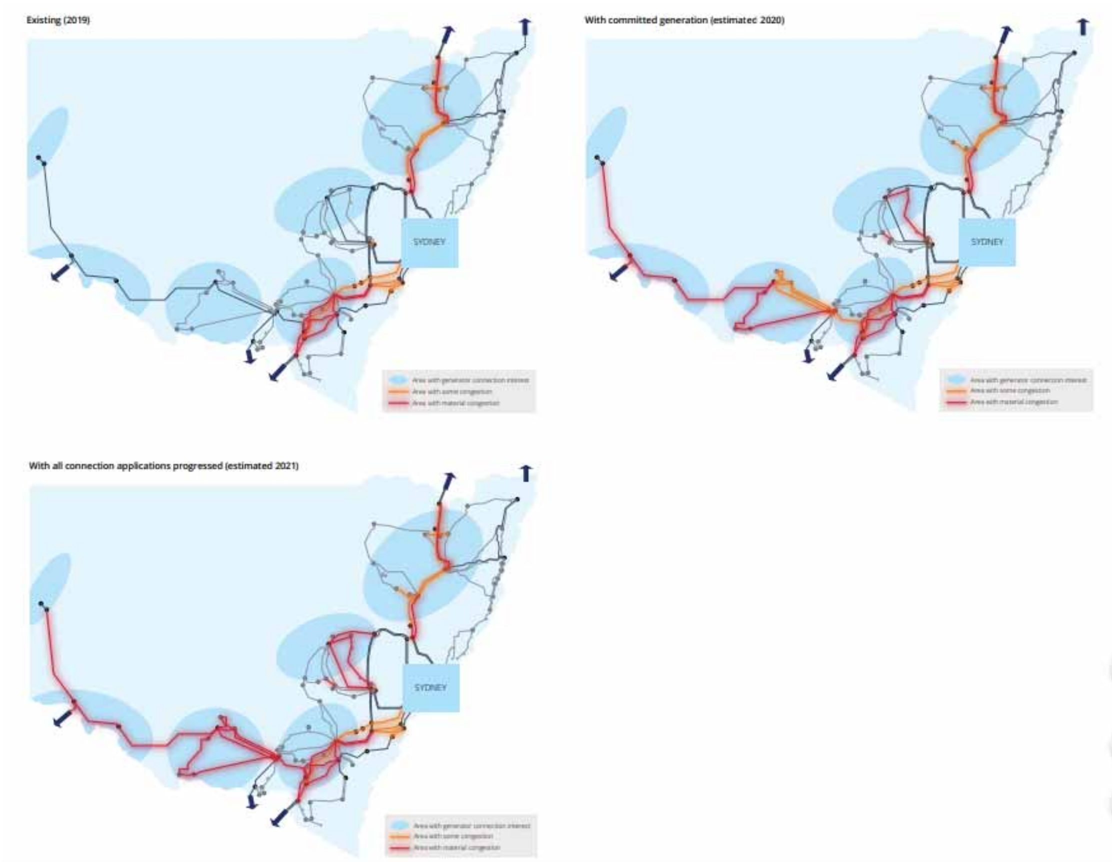
The electricity sector transition that is currently under way is changing the dynamics of the power system:

- Traditional thermal plants are closing, and more renewable and asynchronous generators are connecting to the power system with these newer plants having a different generation profile. In addition, the introduction of 5 minute settlement reforms will further incentivise more flexible types of generation technologies over the coming years, particularly large-scale storage.
- The networks across the NEM are becoming more meshed and interconnected (both within and across regions), with this being combined with increased inter-regional trade and sharing of reserves between jurisdictions.

Generation roughly equal to the current size of the NEM (50 GW) is foreshadowed for connection to the grid over the next 10 years. The national electricity market will replace most of its current generation stock by 2040. Unlike the existing power system, the system of the future is likely to be characterised by a large number of relatively small and geographically dispersed generators. Further, these generators are unlikely to be located where there is substantial existing transmission to serve them instead being connected in sunny or windy areas at the edges of the grid, where the network is less strong. In addition, these new types of generation can in general be built more quickly than transmission infrastructure required to serve it. Substantial and timely transmission infrastructure is therefore likely to be required.

The figure below is taken from TransGrid's recent Transmission Annual Planning Report and shows the existing and forecast significant increase in congestion across its network. Other TNSPs are experiencing similar trends.

Figure 2.1: Congestion in the NSW network



Source: TransGrid, *New South Wales Transmission Annual Planning Report*, 2019, p. 7.

This trend is only going to continue. AEMO's ISP in the 'neutral with storage' modelling scenario shows that by 2030 over 6,000 MW of existing generation is expected to close and be replaced by approximately 22,000 MW of renewable generation and 6,000MW of storage. By 2040, the amount of expected closure increases to approximately 16,000 MW, which is projected to be replaced by 50,000 MW of renewable generation and 20,000 MW of storage.

If a faster and bigger transformation occurs, then these values will increase and occur sooner.

These changes mean that there is a need to have a better way of co-ordinating generation and transmission investment decisions in order to better facilitate the transition that is occurring.

2.2 Access reform will coordinate generation and transmission investment

The existing transmission access regime, where all generation and load is settled on a region-wide price for its physical output or consumption (net of losses), was a central design choice in establishing the NEM. This choice reflected a compromise between reflecting the underlying realities of the system and the benefits of a simple unified price model, and was fit-for-purpose in an environment of relatively low levels of generation and transmission investment, where the transmission risks faced by generators are relatively predictable and stable.

However, this design choice is no longer appropriate given the emerging environment, and a number of consequences of the original design have become significant and more challenging to manage.

The current framework has a **lack of locational signals** in the wholesale pricing framework. Coupled with the speed and scale of connections, private sector investors are placing their generation and storage assets where the network has limited or no capacity for the additional generation capacity to be dispatched. Under the current framework, these parties are finding it difficult to manage the risk that the existing transmission network will not be sufficient to accommodate them.

The current wholesale pricing arrangements are sending **adverse operational incentives to generators and storage** and leading to higher wholesale prices over the longer term.

For example, generators are incentivised to bid unavailable in certain situations because the regional price does not reflect their marginal cost of supply. This leads to AEMO needing to give directions and results in a less **reliable, more costly power system**.

In addition, generators are currently incentivised to bid in at the market price floor when they are behind a transmission constraint ('race to the floor' bidding). Race to the floor bidding means that the lowest cost available generator is not always dispatched, which can **increase the wholesale cost of electricity** over the longer term for consumers.

In light of the electricity market transition, prospective generators and storage **require greater certainty** that their assets can remain profitable even if subsequent parties connect to the network and create congestion or adverse loss effects. Currently, since a generator's revenue from the wholesale market is determined by how much it is physically dispatched for, when it is not dispatched due to congestion (such as someone locating next to it), it receives no revenue.[10] In practice, this means that given the scale of connections, generator's existing businesses cases are being undermined and changed through the pace of transition. Generators have limited certainty and so it is harder for generators to gain access to finance. Prospective generators require and want greater certainty that their assets can remain profitable even if subsequent parties connect to the network and create congestion.

This is being reflected in the debate around the significant changes in annual marginal loss factors that are currently being experienced. As patterns of generation and demand change across the power system, the **transmission losses** that can be associated with a particular market participant also change. Currently, the annually set marginal loss factors can change substantially from year to year depending on what parties connect near and around the

10 Generators currently have a right to be connected, but no right to be dispatched.

generator. Such significant changes can also affect a generator's revenue and its business case.

The level of **transmission infrastructure** also influences the level of congestion. The most efficient level of congestion is not zero: building out all congestion would be very costly; having lots of congestion means that more expensive generators will be dispatched over lower cost generators. There are concerns at the moment that transmission infrastructure is not being built fast enough to facilitate the right level of congestion. In the current climate, it is also clear that consumers have concerns about projected costs and increased bills in order to pay for the new transmission necessary for the transition. This is because it is consumers who currently pay for transmission infrastructure.

Transmission access reform is vital for the NEM to effectively evolve, transition, and co-ordinate investment resulting in least-cost wholesale outcomes for consumers. The proposed model will address the issues raised by market participants, consumer groups, and observed and foreshadowed by the ESB, AEMC and other market bodies.

Our proposed model is a holistic long-term solution to issues raised by market participants, consumer groups, and observed and foreshadowed by the ESB, AEMC and other market bodies. It can address the concerns discussed above:

- Generators and storage will be able to obtain more certainty over the operation and revenue of their assets, in return for paying for financial transmission rights.
- Generators and storage will have improved incentives to locate in areas of the network which are most beneficial for the power system, and to operate efficiently.
- Consumers will benefit by having renewable energy zones being facilitated, which should lower wholesale market prices. Our proposals also return the proceeds from the financial transmission right auctions to consumers, lowering TUOS charges.
- AEMO and networks will have more information to incorporate into their transmission planning and investment decision-making processes.

The broader benefits from the proposed model are explored in the next chapter.

3 OVERVIEW OF PROPOSED MODEL

BOX 1: REVIEW TERMINOLOGY

This paper uses the following specific terminology to more clearly reflect the nature of the proposed model:

- **Financial transmission rights** are discussed rather than transmission hedges or firm access rights. This is to clearly delineate the products being sold from those available in the forward contract markets. In addition, it aligns our terminology with that used in overseas jurisdictions.
- **Local prices** or **locational marginal prices** (LMPs) are used to refer to the new wholesale electricity prices that would be introduced for scheduled market participants, such as most generators and storage, under the model. The concept of locational marginal prices emphasises the fact that this price is the cost of supplying an additional unit of load at the generator's local node.
- **Dynamic regional pricing** refers to the changes to wholesale electricity pricing in full. That is, that:
  - scheduled market participants, such as most generators and storage, would face a locational marginal price for wholesale electricity
  - retailers and other non-scheduled market participants would continue to be settled at a regional price for wholesale electricity
  - marginal loss factors will be replaced by loss factors that are determined dynamically through dispatch.
- **Financial payout** or **financial returns** under the financial transmission rights are discussed rather than compensation payments. Under the proposed model, there is no question of 'compensation' relative to the regional price, as scheduled and semi-scheduled market participants are dispatched and priced with reference to the LMP.

This chapter provides:

- an overview of our proposed access model
- explains the expected benefits of the proposal
- a discussion of how the model interacts with other market processes under way.

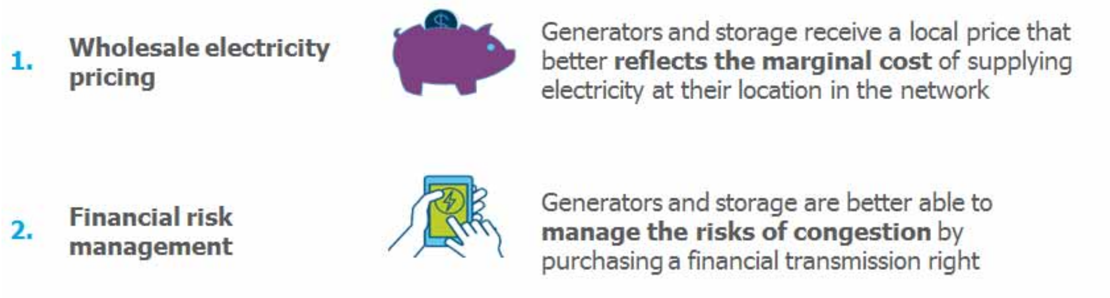
3.1 Overview of the proposed model

The Commission's proposed access model is a holistic long-term solution to many of the issues raised by generators, retailers, storage operators, investors, consumer groups and market bodies.

Our proposed access model focusses on changing two key pillars of the transmission access framework (outlined in Figure 3.1):

- wholesale electricity pricing, by introducing **dynamic regional pricing**
- financial risk management, by allowing generators, storage and other scheduled market participants to better manage the risks of congestion through purchasing a **financial transmission right**.

Figure 3.1: Overview of proposed access model - focus is on first two pillars



Source: AEMC

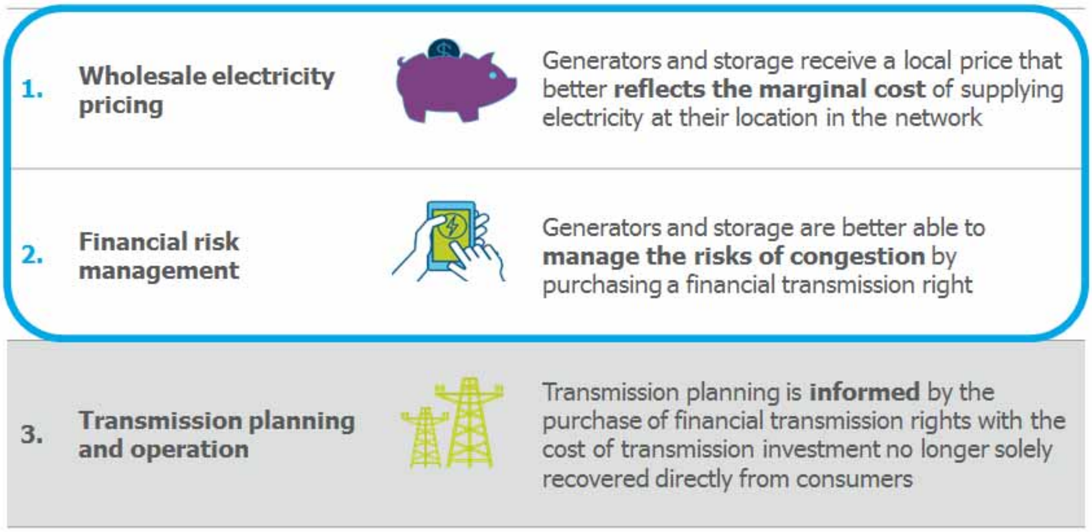
3.1.1 Policy evolution

This section summarises how our proposed model has evolved in response to stakeholder input and feedback.

The June directions paper had proposed three pillars, with the third pillar being related to transmission planning and operation. However, in response to the directions paper, many stakeholders suggested that a model with dynamic regional pricing and financial transmission rights that did not directly link to the transmission planning framework would be preferable.[11] That is, they favoured a model that was limited to the first two elements described in Figure 3.2.

11 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, directions paper submissions: AER, p. 1; AusNet Services, p. 3; Clean Energy Council, p. 2; Energy Networks Australia, p. 5; Major Energy Users, p. 5; TransGrid, p. 1; AEMO, p. 5.

Figure 3.2: Overview of the previous model - we are no longer focussing on the third pillar



Source: AEMC

Stakeholders generally agreed with the Commission that it was important for financial transmission rights to effectively interface with the transmission planning regime, including the Integrated System Plan that is currently being actioned by the ESB. Most stakeholders supported the Integrated System Plan leading the transmission planning and investment decision making process to develop whatever transmission investment is necessary. The existing and planned transmission network would be used as a guide to how many financial transmission rights would be available for purchase.

Given this feedback, as well as the need for this to interface effectively with the ESB's work on *Actioning the ISP*, we agree that the reform should focus on the first two elements of the model.[12] Through the COGATI review and other projects, we have received consistent feedback from stakeholders that investors are facing significant challenges in quantifying the risks associated with regulatory and policy change in the NEM. To pursue this third limb may put in place an additional level of risk on generators, storage and investors that would not be justified.

Therefore, under our proposed model, transmission planning and investment would continue to be conducted using the current regulated process, including the ISP. Following this, an amount of financial transmission rights that takes into account the physical capacity on the network would then be available for purchase by generators, storage, retailers and other market participants.

12 The interaction with the ESB's work is described further below.

To be clear, and in contrast to our earlier proposal, the amount of financial transmission rights available would be limited to the aggregate amount of transmission capacity (both committed and currently available) as determined by AEMO in conjunction with the TNSPs.[13]

The introduction of financial transmission rights will still *indirectly* influence transmission planning and investment decisions over time. For example:

- Financial transmission right auction outcomes could reveal the level of demand from generation for access to a particular part of the transmission network. This information may be useful to inform the development of future strategic and project plans.
- The framework should create a larger incentive for generators, retailers and storage to engage in future planning and investment processes, such as the ISP and TNSP's Annual Planning Reports. This is because the amount of financial transmission rights will directly correspond with the transmission investment decisions made.
- At any given time, transmission planning will take account of the existing and committed stock of generation across the network. As the introduction of the model is expected to result in different, and more efficient, locational decisions by generation and storage assets, this in turn should result in an improved plan for transmission investment.

3.1.2 First element: wholesale pricing changes

What is dynamic regional pricing?

The first element of our proposed model is to change the wholesale electricity price that is applied to generators, storage and other scheduled market participants so that it more accurately represents the marginal cost of supplying electricity at their location in the network. This is called dynamic regional pricing, and its key elements are:

- generators, storage and other scheduled and semi-scheduled market participants would face a locational marginal price for wholesale electricity
- retailers and other non-scheduled market participants would continue to be settled at a single regional price for wholesale electricity
- static, annually determined marginal loss factors would be replaced by marginal loss factors that are determined dynamically through the dispatch process.

A key aim of any transmission access regime should be to provide efficient price signals to generators and storage, such that they make operational and investment decisions that reflect the marginal cost of generating and transporting electricity to consumers.[14] The first aspect of model aims to improve the efficiency of pricing signals in the NEM by changing the wholesale electricity prices that generators, storage and other scheduled market participants are settled at.

Under the current framework, all forms of generation and load are subject to the same regional reference price for each megawatt hour of electricity they consume or dispatch,

13 Rather than being determined directly by market through their financial transmission right purchasing decisions, as previously proposed.

14 Efficiency is promoted when prices reflect the marginal cost of the provision of a particular product or service, as well as any positive or negative externalities.

regardless of where they locate in a region. This price is adjusted by a static marginal loss factor in order to account for the effects of transmission losses in the system.

We are proposing to change these arrangements so that generators, storage and other scheduled market participants face a dynamic regional price that more accurately represents the marginal cost of supplying electricity at their location in the network, including the costs of congestion and losses.

BOX 2: ALGEBRAIC REPRESENTATION OF THE ACCESS MODEL

The issues with the current arrangements can also be illustrated with some basic mathematics.

Currently, market participants are settled at the regional reference price (RRP) for their physical dispatch (ignoring losses for ease of explanation):

Revenue = RRP x physical dispatch [1]

This seemingly innocuous and fundamental equation in the design of the NEM is the root cause of problems we are seeking to fix using our proposed access model:

- Market participants are settled at the regional reference price. This is not an efficient price signal because it does not signal the value of energy at their location in the network. Regional reference pricing therefore creates perverse incentives in both operational and investment time-scales.
- Market participants' revenue through the spot market is entirely a function of physical dispatch, which means that market participants are limited in their ability to manage the risk that their physical dispatch is curtailed in the presence of transmission congestion.

Rearranging equation [1], we get the following, mathematically identical equation:

Revenue = LMP x physical dispatch + (RRP — LMP) x physical dispatch [2]

The LMPs in this equation cancel out, so market participants are only exposed to the RRP (as per equation [1]). But LMPs are currently calculated by the dispatch engine, and the physical dispatch of market participants is determined in relation to these LMPs. This is the first term in the equation above.

The second term is being implicitly allocated to market participants automatically, through the settlement process. It is so deeply embedded in the NEM design that many stakeholders barely give it a second thought. It creates a simple and intuitive outcome: all generators and load in a region are settled at the same price, meaning there is no (visible) settlement residue (ignoring losses and inter-regional flows).

What we are proposing through the access model is take the second term, summed up over all generators, and reallocate it FTR holders:

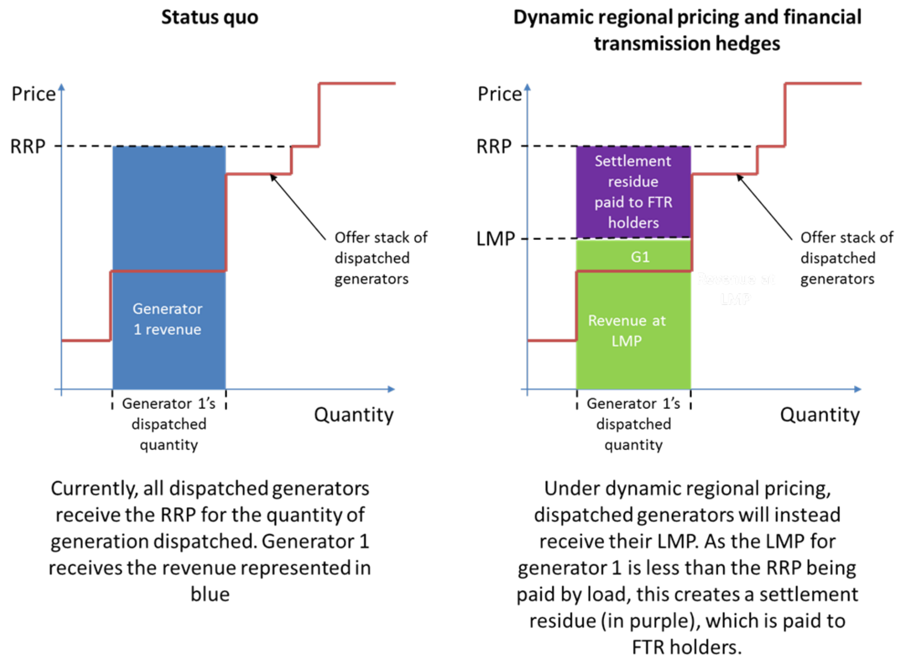
Revenue = LMP x physical dispatch + (Locational price 1 — Locational price 2) x FTR quantity [3]

This solves the two problems with the current arrangements identified above:

1. Market participants are settled at their LMP, not the RRP, which is an efficient price signal.
2. Market participants' spot market revenue has been partially decoupled from physical dispatch, meaning that market participants are able to manage the risk of congestion by acquiring FTRs. When congestion arises, this creates locational price differences and resulting FTR payments through the second term in equation [3].

The changes being proposed are illustrated below:

Figure 3.3: Graphical representation of access model



Source: AEMC

For those market participants not exposed to the local price (i.e. most retail load), settlement remains unchanged. That is, the payment made by retailers on behalf the majority of load will continue to be as per equation [1].

Note: The type of financial transmission rights that would be offered would be option instruments, which only ever result in a positive payment.

Benefits of dynamic regional pricing

We consider that dynamic regional pricing should improve the **incentives for generators, storage and other scheduled market participants to operate efficiently**. That is, it should incentivise them to bid 'available' and at a price reflective of their costs.

In contrast, the current wholesale pricing arrangements are sending adverse incentives to generators and storage, and leading to higher wholesale prices over the longer term. For example, generators are incentivised to bid unavailable in certain situations because the regional price does not reflect their marginal cost of supply. This leads to AEMO needing to give directions and results in an unreliable, more costly power system.

In addition, generators and storage are currently incentivised to bid in at the market price floor price when they are behind a transmission constraint (‘race to the floor’ bidding). This increases the cost of electricity over the longer term for consumers.

Dynamic regional pricing should remedy this by paying scheduled and semi-scheduled generators and storage a price that is more reflective of the cost of generating electricity in each part of the grid. In turn, this should:

- lead to a reduction in the amount of generators bidding 'unavailable', therefore reducing the amount of directions that AEMO needs to give
- eliminate race to the floor bidding by generators and storage, which is currently contributing to higher electricity costs for consumers.

In addition, dynamic regional pricing could contribute to **improved locational signals** in investment time-scales. This is because exposure to locational marginal prices would provide better information to generators, storage and other scheduled market participants on the value of locating in different parts of the network. Better locational investment by generators and storage should, in turn, result in less congestion than would otherwise be the case. This should mean that the development of the transmission network over the longer term is more efficient, ultimately lowering costs for consumers.

We consider that the locational signals are likely to be especially effective for generation technologies that are relatively quick to deploy and are price sensitive, such as storage. Dynamic regional pricing should improve the business case for storage devices to bolster system security and reduce wholesale prices in certain parts of the grid.

Finally, we consider that dynamic regional pricing should improve the **efficiency of dispatch** by more accurately measuring the effects of losses within the system. Introducing dynamic loss factors will help to ensure the lowest cost combination of generation is dispatched at any given time, which should lower costs for consumers.

A more detailed explanation of the above features of dynamic regional pricing is provided in Chapter 4.

3.1.3 Second element: financial risk management

What are financial transmission rights?

The second aspect aims to improve the financial risk management options for generators, storage, retailers and other market participants. We are proposing to enable generators, storage, retailers and large load customers to better manage the risks of congestion and transmission losses by enabling them to purchase financial transmission rights.

These products will hedge against the price differences that may arise under our proposed changes to wholesale electricity prices, including price differentials from congestion and losses.[15]

Benefits of financial transmission rights

Under the current arrangements, generators, storage, retailers and other market participants are unable to manage the risks of congestion and losses effectively. For example, a generator's ability to earn the regional reference price through the market is totally dependent on it being dispatched. Similarly, generators and storage are unable to control their marginal loss factor once they have made an investment decision.

In contrast, under the new framework, financial outcomes would be partially decoupled from physical dispatch. If a generator or storage device had purchased a financial transmission right, then it would be paid if its local price differed from the strike price in the financial transmission right. This payment would occur even if it was:

- a generator that was not dispatched or dispatched at an amount below its preferred output
- subject to a dynamic loss effect than was more variable than expected.

Similarly, retailers and other market participants on the demand side of the market will be able to purchase a financial transmission right in order to manage any risks that accrue to them under the terms of forward contracts, such as power purchase agreements.

The revenue to back the financial transmission right is the settlement residue that arises between what generators are being paid and what load is paying under dynamic regional pricing.

These arrangements should improve **investment certainty** for generators and storage and may **reduce their cost of capital** in the longer term. This is because generators and storage with financial transmission rights would face less risk that other participants who may undermine their business case by locating nearby and causing congestion or adverse loss effects in the local transmission system.

This should also improve participants' willingness to offer energy contracts, improving **contract market liquidity**, both within regions, but also across regions. This will occur because parties will be able to better manage the risk of congestion. Market participants should also be able to better manage the risk of contracting for electricity with counterparties located in different regions of the NEM. This should further improve liquidity in the contract market by providing participants with a wider pool of possible counterparties, particularly as the NEM regions become more interconnected.

In addition, the introduction of financial transmission rights should enable **TNSPs to manage their year-to-year cashflows more effectively.** This is because the proposal will abolish the current settlement residue auction (SRA) units and replace them with inter-regional financial transmission rights that are firmer and more valuable to market

15 Noting that the type of financial transmission rights that would be offered would be option instruments, which only ever result in a positive payment.

participants. The money for these financial transmission rights will be paid out directly through AEMO's settlement system, so TNSPs will no longer need to incur costs associated with holding SRA funds that create issues arising from year-to-year cashflow management.

Finally, the introduction of financial transmission rights should **improve the operation of the transmission network**, as it will be accompanied by an improved operating incentive scheme for TNSPs.

A more detailed explanation of the above features is provided in Chapter 5 and Chapter 6.

3.2 Benefits of the proposed model

Our proposed model is a holistic long-term solution to issues raised by market participants, consumer groups, and observed and foreshadowed by the ESB, AEMC and other market bodies. It can address the concerns discussed in Chapter 2:

- Generators and storage will be able to obtain more certainty over the operation and revenue of their assets, in return for paying for financial transmission rights.
- Consumers will benefit by having renewable energy zones being facilitated, which should lower wholesale market prices. Our proposals also return the proceeds from the financial transmission right auctions to consumers, lowering TUOS bills.
- Networks will be able to gain more certainty over their processes, as well as to more effectively manage their year-to-year cashflows.

Our proposal to introduce dynamic regional pricing and financial transmission rights should result in the following benefits to the NEM:

1. better incentives to operate generation and storage assets efficiently
2. better incentives for efficient generation and storage investment
3. more efficient dispatch of electricity
4. better risk management for market participants
5. better year-to-year cashflow management for TNSPs
6. better incentives to operate the transmission network efficiently.

The broader benefits from the proposed model are explored in more detail below.

3.2.1 Better incentives to operate generation and storage assets efficiently

The wholesale market determines the prices and quantities generated and purchased every trading interval in every region of the NEM i.e. the operation of generation and storage assets. However, the wholesale cost of electricity is not the product of these quantities and prices but is driven largely by the outcome of contracts struck between generators and retailers. The prices for electricity paid by retailers to generators in these contracts smooth the costs and revenues associated with the much more volatile wholesale prices determined in the spot market. Therefore, the below discussion needs to be considered with that in mind.

The current market design does not send the right incentives to generators to operate efficiently (that is, to bid available and at a price reflecting their marginal costs). This may be leading to higher wholesale prices for consumers.

Bidding unavailable

Depending on their contract position at the time, generators are currently incentivised to bid 'unavailable' in certain situations because the regional price does not reflect their marginal cost of supply. For example, a generator that is required to run for system security purposes may be able to exhibit non-competitive market conduct through bidding 'unavailable' and being directed on to generate by the market operator.

Generators who are directed on to provide energy (or FCAS) are currently compensated at the 90th percentile of spot prices over the preceding 12 months (the 'P90' price).[16] If the regional reference price is less than the P90 price, then the generator may (rationally) bid 'unavailable' in order to receive a higher price for its output.

There is evidence that this phenomenon is leading to higher costs and a more unreliable power system for consumers. For example, our recent *Interventions into system strength* review found that during the recent system strength interventions in South Australia, wholesale spot prices were typically much lower than the directed payments that AEMO made.[17] This is because these interventions tend to occur during periods of high wind output and low demand in South Australia.

Race to the floor bidding

Generators and storage behind a transmission constraint are often able to forecast that congestion is likely to arise. For example, AEMO publishes information in pre-dispatch systems that enable generators and storage operators to identify the likely impact of transmission constraints on their assets.

When the system is congested, generators and storage know that the regional reference price is likely to be higher than usual, and that they are not going to receive access to it unless they are dispatched. If a generator or storage device is not dispatched, it may risk losing significant revenue due to the position it has taken under hedge market contractual obligations.

These conditions can give rise to race to the floor bidding. Race to the floor bidding results when generators or storage devices know that the offers they make will, in all likelihood, not affect the settlement price they receive as a result of congestion between them and the rest of the market. Race to the floor bidding can involve a generator or storage device behind a constraint bidding at the market floor price (-$1,000) to maximise its dispatch quantity. This can result in inefficient dispatch through higher cost generation resources being dispatched instead of lower cost resources.

16 Directed participants can also lodge a claim for additional costs, including loss of revenue, if payment at the 90th percentile price or the fair payment price is not adequate to cover their costs. However, a $5,000 threshold per trading interval applies to claims for additional compensation.

17 AEMC, *Investigation into intervention mechanisms in the NEM*, Final report, 15 August 2019, p. 40.

How dynamic regional pricing should improve these issues

Dynamic prices more accurately signal the value of supplying electricity at each location, and do not impose the same perverse incentives on generators or storage devices to operate their assets inefficiently.

For example, exposing generators and storage devices to the dynamic regional price removes the incentives to engage in race to the floor bidding when transmission constraints arise. Under these circumstances, the higher cost participant may lose further revenue if it places a bid at the floor price, as such behaviour runs the risk of depressing the local price which they receive to lower than their costs.

Similarly, generators and storage devices should no longer be incentivised to bid 'unavailable' when the regional reference price is lower than their cost of supply. This is because they will be able to access a higher local price if their electricity generation is needed.

A key aim of any transmission access regime should be to provide appropriate price signals to generators and storage such that they make operational decisions that efficiently reflect the costs of generating and transporting to consumers. Efficiency is promoted when prices reflect the marginal cost of the provision of a particular product or service, as well as any positive or negative externalities. The Commission considers that dynamic regional pricing should send the right incentives to generators and storage devices in order to improve the prospect of the lowest cost combination of generation being dispatched.

3.2.2 Better incentives for efficient generation and storage investment

Due to the current lack of locational price signals in the transmission framework, investors have located their generation or storage assets where the network has limited or no capacity for the additional generator capacity to be dispatched.

For example, a generator or storage investor may choose a location optimal for fuel resources but which has poor levels of existing transmission capacity. While the generator or storage device faces the risk that its output is less than would otherwise be the case due to the likelihood that transmission congestion will arise, these signals are not explicit through the price it receives for its generation, and so are unlikely to be efficient.

Current locational signals such as transmission losses, congestion and inter-regional price variation do provide a degree of incentive for efficient generator or storage location. However, these signals are incomplete, imprecise and difficult to predict given the volume and speed of additional new generation connecting to the network.

How dynamic regional pricing should improve these issues

Dynamic regional pricing could contribute to improved locational signals for generators and storage over the long term, as exposure to locational marginal prices provides better information on the value of locating in different parts of the network. This is particularly true for technologies that are relatively quick to deploy and are sensitive to changes in prices, such as storage devices.

We consider dynamic regional pricing would create a clear and cost-reflective locational signal for new generation and storage investment that is currently missing in the NEM. Locational signals would be provided to generators and storage through local prices that reflect the incremental cost of congestion and loss effects that the participant would impose on the transmission system.

Generators and storage investors would then trade off different locations, taking into account the relative costs of transmission factors, as well as the other factors such as fuel costs. While there are a number of other factors investors consider when making locational decisions, these signals may make a difference in some cases, and would result in more efficient locational decisions being made in the longer term. This should, in turn, result in less need to build out the transmission network, ultimately lowering costs for consumers.

3.2.3 More efficient dispatch of electricity

Transmission losses are currently factored into dispatch through the application of static annual marginal loss factors. However, actual marginal losses vary dynamically, depending on flows on the transmission network.

Therefore, there will naturally be some dispatch inefficiency arising from differences between actual marginal loss factors and the assumed (static) marginal loss factor. Intuitively, if we assume that the static loss factors represent an unbiased estimate of average marginal loss factors, the degree of inefficiency is likely to be proportionate to how much these loss factors vary from the average on a thirty-minute by thirty-minute basis.[18]

There are several trends that may be contributing to increasing variance in actual marginal loss factors, related to the speed, volume and type of generators connecting to the system. For example, the variable nature of some renewable generators could be expected to increase the volatility in actual marginal loss factors. These trends are also causing substantial changes in the annually set marginal loss factors.

Further, the number, size and use of interconnectors within the NEM is expected to increase. Taken together, the increase in grid interconnectedness alongside the rise in variable renewable generation may lead to more frequent reversals of flow direction along and near interconnector routes (as clusters of generation turn on and off in response to weather patterns). This trend would, in turn, potentially change whether the actual marginal loss factors for associated nodes are greater or less than one[19], which may further increase volatility in the annually set loss factors over time.

How dynamic regional pricing should improve these issues

Under dynamic regional pricing, we are proposing that intra-regional and inter-regional losses would be calculated dynamically in dispatch.

The benefits that accrue from adopting dynamic loss factors largely relate to more efficient dispatch. For example, if the static marginal loss factor is very different from the actual

18 Soon to be a five-minute by five-minute basis, with the implementation of five minute settlement.

19 This would change whether the price at the node is greater or less than the regional reference price.

marginal loss factor in any given dispatch interval, this could lead to generators with higher loss-adjusted costs being dispatched ahead of lower cost generators. If intra-regional losses were modelled dynamically in dispatch, the productive efficiency of the dispatch engine could be improved.

However, we recognise that moving to dynamic loss factors could potentially increase volatility of loss factors. Generators, storage and investors today are expressing concerns with the increased volatility in their annual marginal loss factors from year to year. Therefore, we consider it important to combine the introduction of dynamic loss factors, with the introduction of a product that will allow generators to hedge against changes in loss factors. This is discussed further in Chapter 5.

BOX 3: IMPLEMENTATION OF LOCATIONAL PRICING IN ERCOT (TEXAS)

In December 2010, ERCOT transitioned from a zonal market design to a market design that incorporated locational marginal pricing for participants. This transition was widely viewed to be successful in creating more efficient market outcomes.

Key findings from the first year of operation found that, amongst other things:

- There was less pricing volatility under a locational marginal pricing regime than in the zonal market.
- There was a better correlation between the wholesale price of electricity and demand at any given time.
- The existing transmission network was used more effectively, with less transmission constraints binding.

Overseas experiences implementing locational marginal pricing may be useful for our policy design and decision-making processes. However, it is important to note that each jurisdiction has unique circumstances that make straightforward comparisons difficult.

Source: Potomac Economics, *2011 State of the market report for the ERCOT wholesale electricity market*, July 2012

3.2.4 Better risk management for market participants

Another issue under the current framework arises even when generators or storage devices choose to connect where there is relatively good access to the transmission network and little current congestion. Under the current access frameworks, there is nothing to stop a subsequent generator or storage device connecting beside it and effectively constraining off that first participant, undermining its ability to earn revenue from the wholesale market and so its business case. When generators or storage decide to locate in a congested area, the broader system benefits that result from the additional investment are also undermined.

The risk of congestion also reduces the incentives for market participants to sell contracts, because their quantity dispatched may be adversely affected and so they have insufficient revenue from the spot market to cover their payouts in the contract market. The proposal should improve participants' willingness to offer energy contracts, improving contract market liquidity, because they can better manage the risk of congestion. Market participants should also be able to better manage the risk of contracting for electricity with counterparties located in different regions of the NEM. This should further improve liquidity in the contract market by providing participants with a wider pool of possible counterparties.

Having made a locational decision, a generator or storage device is not readily able to manage the risks arising from transmission losses, congestion, and to a lesser extent, inter-regional price variation.

In addition, TNSPs have advised us that they are experiencing issues arising from year-to-year cashflow management as a result of managing the funds for inter-regional settlement residue auction (SRA) units.

How financial transmission rights should improve these issues

The new transmission access model should improve financial certainty for generators, storage devices, retailers and other market participants who purchase financial transmission rights. Under the new arrangements, generators and storage devices would be able to more effectively manage their dispatch risk during times of congestion in return for buying financial transmission rights. In turn, the money collected from the sale of financial transmission rights will go to consumers to offset the money they have paid to build the transmission network.

These arrangements should improve investment certainty for generators and storage devices and may reduce the cost of capital in the longer term. This is because participants with a financial transmission right would face a lower risk that other participants may undermine their business case by locating nearby and causing congestion in the local transmission system.

Under the status quo, a generator or storage device's ability to earn the regional reference price is dependent on it being physically dispatched. In contrast, under a financial transmission rights regime, financial outcomes would be decoupled from physical dispatch.

The Commission also envisages that inter-regional financial transmission rights would replace the existing inter-regional settlement residue products. Since AEMO will manage both the intra- and inter-regional residues going forward through the settlement process, this means that TNSPs will no longer have to do this. This should improve the ability of TNSPs to manage their year-to-year cashflow more effectively.

3.2.5 Better incentives to operate the transmission network efficiently

Under the current framework, TNSPs are required to maintain and upgrade their equipment in order to provide services in line with relevant network performance requirements. This occasionally requires outages to be planned on the power system to facilitate the safe maintenance and upgrade of network infrastructure.

TNSPs must provide information on the timing of planned outages through AEMO’s network outage scheduling tool and in 13 month plans. For generators or storage devices connected to network assets undergoing maintenance, there may be a period where there is a need to curtail output or disconnect to manage system security for the next contingency, or where network equipment is de-energised to allow safe work.

Where unplanned outages are extended or prolific, this can cause significant effects on a generator or storage device's revenue, with no compensation currently available. To incentivise transmission businesses to reduce the impact of planned and unplanned outages on wholesale market outcomes, the AER currently administers the Service Target Performance Incentive Scheme (STPIS). However, this operating scheme is not directly tied to measures of market value, which may decrease its effectiveness.

How the proposed model should improve these issues

The Commission considers that, while the Service Target Performance Incentive Scheme has incentivised TNSPs to improve network performance,[20] it would be better to have an incentive scheme that covers all periods and is better tied to measures of market value.

An enhanced incentive scheme would better encourage TNSPs to maximise network availability at times of high market demand, which in turn would lower wholesale market prices for consumers over the longer term. It should be noted that it is inefficient for a TNSP to operate and plan its network to provide capacity for settlement residue to be sufficient to cover the cost of financial transmission right payouts at all times.[21]

To account for this reality, the proposed model incentivises TNSPs to operate their network efficiently in order to provide sufficient capacity to meet financial transmission rights payouts. The symmetrical incentive scheme targets TNSPs to efficiently manage their network with regard to congestion at all times. However, the inputs into the incentive scheme would be refined to be based on more granular data that would become available under our model. Under such an enhanced scheme, the financial incentives on TNSPs would be sharper to provide a level of physical capacity greater than the amount of financial transmission rights collectively held by generators.

While the incentive scheme would enhance the existing Service Target Performance Incentive Scheme, its strength (i.e. the revenue at risk) would be the same. This is to avoid significantly altering the TNSPs' risk profile.

3.3 How does the proposed model interact with other reforms under way?

The Commission is mindful to ensure that reform in the sector is undertaken in a coordinated manner, both for those reforms being led by the AEMC, and those reforms being led by other organisations such as the ESB, of whom the AEMC is a member organisation.

20 As part of the optional firm access, design and testing, review in 2013, the Commission conducted analysis on the effectiveness of the STPIS scheme. It was found that, typically, incentives to TNSPs under the scheme have increased over time reflecting better performance in minimising outages. AEMC, Optional Firm Access Design and Testing, Final Report - Volume 1, 9 July 2015.

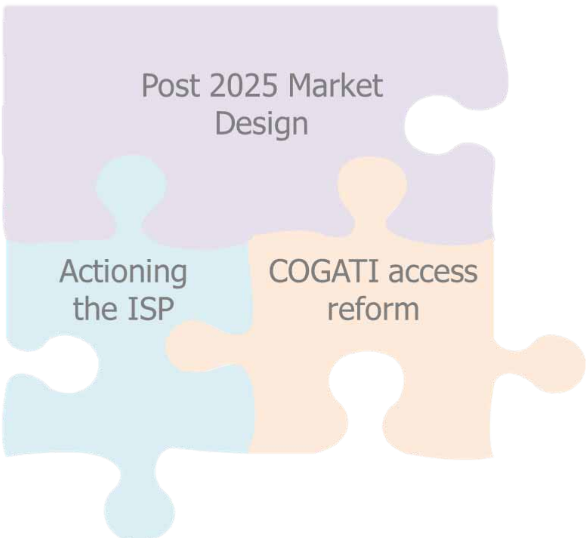
21 There may be circumstances affecting capacity on the network that are caused by events outside the TNSP's control, such as a bushfire. Further, TNSPs need to reduce capacity at times when it is not valued (for example, during off-peak times) for actions such as maintenance. It would not be possible to require sufficient capacity to cover the cost of financial transmission right payouts under these conditions.

The Commission welcomes a recent report by KPMG, commissioned by the Australian Energy Council, which outlines a framework to improve the coordinating electricity market reform.[22] The Commission will consider incorporating elements of the proposed framework into its decision-making going forward, with this discussed further in appendix A.

In this light, the proposal put forward in this paper is consistent with the market reforms currently led by the Energy Security Board, including:

- the process of actioning the Integrated System Plan
- the Post 2025 Market Design review.

Figure 3.4: Integration of market reforms



Source: AEMC

3.3.1 Actioning the Integrated System Plan

In its *Integrated System Plan; Action Plan* report, the ESB identified the importance of changing access arrangements and noted that it will report back to the COAG Energy Council by December 2019 on its views on congestion and changes to the access framework:[23]

Recommendation 12: The ESB recommends that as part of their work they report back to the COAG Energy Council in 2019 on the REZ connections, access and congestion - and options for addressing them.

The Commission is working closely with the ESB on these issues in order to make sure that a coordinated and cohesive plan is being developed.

22 KPMG, Coordinating electricity market reform, September 2019.

23 For more information, see http://www.coagenergycouncil.gov.au/sites/prod.energycouncil/files/publications/documents/isp%20action%20plan.pdf

The ESB also has a project under way to action the Integrated System Plan. It published a consultation paper for this project on 17 May 2019, which provided a high-level structure for a regulatory framework to make the ISP actionable. We understand that the ESB is publishing draft rules for consultation shortly on this.

Our proposed model works with the actioned ISP to facilitate transmission infrastructure that is in the long-term interests of consumers. It helps to deliver on an actioned ISP that aims to deliver the least cost combination of transmission infrastructure and non-network (generation and demand side) solutions to meet the load-side reliability standard.

Under our proposal, the regulated planning and investment processes would determine the amount of network capacity and so financial transmission rights available for purchase, with the subsequent sale of these financial transmission rights providing better information for transmission planning over time. The two proposals therefore work hand-in-hand.

3.3.2 Post 2025 Market Design

The ESB is also currently undertaking a project for the COAG Energy Council. This project will advise on a long-term fit for purpose market framework to support reliability, modifying the NEM as necessary to meet the needs of future diverse sources of non-dispatchable generation and flexible resources including demand side response, storage and distributed energy resources participation.

An issues paper was published in September that sought feedback on:

- the possible future scenarios that will be used when assessing options for change
- the assessment framework for evaluating market design options
- the opportunities, challenges and risks that need to be considered as the project looks to identify market design options and
- the implications for market design resulting from these opportunities, challenges and risks.

The COGATI proposed model is a key input into this work. As noted by the ESB's issues paper, the COGATI review will determine where on the spectrum of approaches the future market design will lie. Any recommendations the post 2025 project makes will be consistent with the COGATI review and look to build upon the proposals.

The Commission is very concious of these interactions and has sought to design an access model that, while adapting to the NEM to meet the trends arising from the energy transition, also provides flexibility for different future market designs to be explored. We are not pre judging or pre-empting where the ESB's 2025 work will get to.

4 DYNAMIC REGIONAL PRICING

The first element of our proposed model is to change the wholesale electricity price that is applied to certain market participants so that it more accurately represents the marginal cost of supplying electricity at their location in the network. This is called dynamic regional pricing, and its key elements are:

- scheduled and semi-scheduled market participants (which includes scheduled loads such as storage) would face a locational marginal price for wholesale electricity
- non-scheduled market participants would continue to be settled at a regional price for wholesale electricity
- marginal loss factors will be replaced by loss factors that are determined dynamically through dispatch.

The model also introduces an ability for participants to manage where these changes introduce difference in prices.

An introduction to dynamic regional pricing was included in the June directions paper, and is replicated in Appendix B.

4.1 Summary of key design features

The following table provides the specification for the implementation of dynamic regional pricing, for stakeholder feedback.

Table 4.1: Summary of key design features for dynamic regional pricing

ISSUE	PROPOSED DESIGN CHOICE
What participants will face the locational marginal price?	Scheduled and semi-scheduled wholesale market participants (including scheduled loads) would be settled at the locational marginal price at their transmission connection point. Non-scheduled market participants (including retail load) continue to face a common regional price for the region they are located in. Some participants would have the option of becoming scheduled should they wish to face their locational marginal price. Market participants would, however, not otherwise be able to opt in or out of facing a locational marginal price. Where the option of selecting their participation category is available to a market participant and exercised by that market participant, it would have to wait 12 months before it could reverse that decision.
What network constraints will influence locational	Under the proposed approach to dynamic regional pricing, locational marginal prices would differ across the network when certain thermal and non-thermal transmission constraints arise.

ISSUE	PROPOSED DESIGN CHOICE
marginal prices?	These constraints must relate to the shared network and be included in the NEM dispatch engine (NEMDE).
How is the regional reference price calculated?	Ideally, the regional price would be the volume weighted average price (VWAP) for unscheduled demand and supply within the region.
Are loss factors included in wholesale electricity prices?	Locational marginal prices as well as the regional price will include dynamic loss factors.
How are issues of market power dealt with?	The Commission does not envisage that market power will be increased as a result of these reforms. As discussed in Chapter 7, we will undertake specific impact analysis to determine the significance of market power considerations under dynamic regional pricing. If we do need a market power mitigation mechanism, then an ex ante offer cap would be introduced in the event that a generator was deemed to be pivotal (i.e. deemed to have market power at that specific time and location). The offer cap would be set at a value related to the conditions in the wholesale market at the time the cap is applied. In addition, the AER should review its existing wholesale market monitoring functions and processes, with the potential to introduce more stringent provisions in the event of a material problem.

The following sections discuss these elements of the model in greater detail.

It is important to note that the design elements outlined above are interlinked. For example, allowing local prices to rise above the regional price is supported by the adoption of VWAP pricing. These interactions should be considered by stakeholders when providing feedback on the proposed design.

The Commission is particularly interested in views on the internal consistency of the design, how this may impact the contract market and any other practicalities that should be considered.

4.2 What market participants will face the locational marginal price?

BOX 4: SCOPE OF DYNAMIC REGIONAL PRICING

Under the proposed design for dynamic regional pricing:

- Scheduled and semi-scheduled wholesale market participants would be settled at the locational marginal price at their transmission connection point.
- Non-scheduled market participants continue to face a common regional price for the region they are located in. As discussed in section 4.4, ideally, this regional price would be formulated using a different pricing method to current arrangements.
- Participants would have the option of becoming scheduled should they wish to face their locational marginal price. Market participants would, however, not otherwise be able to opt in or out of facing a locational marginal price.
- Where the option of selecting their participation category is available to a market participant and exercised by that market participant, it would have to wait 12 months before it could reverse that decision.

Note: Under the proposal, market participants would only have the option of becoming scheduled to the extent that this an option available to them under the current regulatory arrangements.

In developing this design, we have considered the following (competing) factors:

- the ability of the participant to respond to locational marginal prices
- flexibility for participants to make a choice as to which price they face
- not creating perverse incentives for participants to gain access to a more favourable price
- the effect on liquidity in forward contract markets
- the cost and complexity of implementation
- distributional equity
- market power.

How these factors have influenced our preliminary design are described further below.

4.2.1 Scheduled and semi-scheduled market participants face a locational marginal price

Scheduled[24] and semi-scheduled[25] market participants would face a locational marginal price as these parties are most likely to have the greatest ability and incentive to respond to wholesale pricing signals, in both the short-term and the long-term. These parties include participants on the supply and demand side of the market.

This design choice means that scheduled loads will face the locational marginal price. At the moment, the only scheduled loads currently operating in the NEM are large scale storage. All large-scale storage must currently be scheduled as both a generator and load.[26]

24 A generator with an aggregate nameplate capacity of 30 MW or more is usually classified as scheduled if it has appropriate equipment to participate in the central dispatch process managed by AEMO. The Commission currently has a pending rule change request from the Australian Energy Council, which proposes to lower this threshold to 5 MW

25 A generating system with intermittent output (such as a wind or solar farm), and an aggregate nameplate capacity of 30 MW or more is usually classified as a semi-scheduled unless AEMO approves its classification as a scheduled or non-scheduled generating unit. AEMO can limit a semi-scheduled generator’s output in response to network constraints, but at other times the generator can supply up to its maximum registered capacity.

26 In August 2019, AEMO placed a rule change request with the Commission to create a new scheduled market participant category for bidirectional resource providers, which would include large scale storage.

Making sure large-scale scheduled storage faces the same locational marginal price, regardless of whether it exports or imports, is an important component of the proposed access model. This will provide incentives for storage to locate in constrained areas of the network, where it is needed, since it will be able to benefit from the arbitrage opportunity that arises there, by exporting when the price is high and importing when the price is low.

The Commission also notes that it recently published a draft determination for its *Wholesale demand response* rule change request, under which demand response service providers (DRSPs) would be able to aggregate loads and participate directly in the wholesale market. As set out in the draft determination, DRSPs would be scheduled and participate in the dispatch process. Since these parties are scheduled, then under dynamic regional pricing, these parties would face the locational marginal price.

4.2.2 Non-scheduled participants continue to face a regional price

Non-scheduled participants (regardless of whether they are load or generation) will continue to face a regional price for wholesale electricity. The majority of non-scheduled participants are currently on the demand side of the market, as load. For example, this comprises all retail load.

We note that, generally, load is typically not as price responsive as generation. Many other factors affect the long-term choice of location and the short-term choice of consumption level, most notably the characteristics of the market in which the load is supplying goods and services to, or the intrinsic value of electricity (for example in cooling and lighting homes). Load may have limited choice over where to locate, and even less choice over what energy source to use. The Commission considers it is important for non-scheduled participants to face the regional price, in order to minimise shocks to prices in different locations of the network.

Non-scheduled generation is also likely to be less responsive to pricing signals than other types of generating units. This is because a significant proportion of non-scheduled generators produce electricity as a by-product of an industrial or commercial process, rather than in response to electricity market conditions.[27] These types of generators could be considered to have similar behavioural characteristics to large load customers, such as discussed above.

Another key reason why non-scheduled load should continue to face a regional price is for the purposes of liquidity. If all load were to face a locational marginal price instead of a common regional price, there may be a risk of splitting liquidity in the contract market, as forward contracts would potentially instead need to be struck against different locational marginal prices.

Taking these factors into account the Commission is of the view that retaining a common regional price for non-scheduled participants is an appropriate model for dynamic regional pricing. As discussed further below, the proposed approach to regional pricing will provide

27 For example, the AEMC found that 42 per cent of non-scheduled generation in 2016 could be characterised in this way. Source: AEMC 2017, *Non-scheduled generation and load in central dispatch*, Rule Determination, 12 September 2017, p. iv.

flexibility to transition to more granular price signals for non-scheduled market participants over time, were this found to be in the long-term interests of consumers.

4.2.3 Market participants would have the option of becoming scheduled if they wished to face the local price

It may be the case that larger loads in certain areas of the network might wish to face a locational marginal price, if this is expected to result in a more favourable price. Under our proposal, non-scheduled load can opt in to the locational marginal price if they are willing and able to become a scheduled market participant.

This also means that the proposed design is flexible to evolve with market conditions. For example, we note that the responsiveness of non-scheduled load may evolve over time, as the NEM transitions to a two-sided market with a more active and flexible demand side, as was discussed in the Commission's wholesale demand response draft determination.

We recognise that becoming scheduled is potentially a significant hurdle for an industrial customer, and may discourage some price-responsive loads from facing their local price. Being scheduled is more difficult for a load than for a generator, because consumption levels naturally fluctuate for reasons unrelated to the spot price and a scheduled load would need to constantly rebid in order to remain dispatch compliant.

However, the proposed approach provides some flexibility by allowing non-scheduled market participants to access locational marginal pricing if they choose (and are able) to become scheduled. As there are costs associated with being scheduled, it is expected that the choice to become scheduled in order to obtain a more favourable local price would only be taken up by the largest or most price-responsive loads or non-scheduled generation resources.[28]

For example, if a specific local price was similar to the regional price on average but could sometimes be higher and sometimes lower, only a price-responsive load would benefit from being settled at the local price. This suggests that, under the requirement to become scheduled in order to access locational marginal prices, any migration from regional to local pricing should promote efficiency gains.

4.2.4 Restrictions on moving between scheduled and non-scheduled categories

Under the specification, market participants would have some flexibility to opt in or out of locational marginal pricing to the extent they are willing and able to change their market participant registration category.

This flexibility has some implications for market participants that face a regional price. If a load opts to become scheduled in order to benefit from a local price that is, on average, lower than the regional reference price, the average regional price paid by the remaining non-scheduled load will increase in order to ensure that wholesale settlement balances.

28 In principle, the converse might apply: in a zone with high local prices, a responsive load might be discouraged from becoming scheduled. However, given that only storage loads have opted to become scheduled under the current rules, and since these loads can easily avoid a high local price by not charging or pumping at those times, this effect may not be significant.

The Commission is concerned that being able to select scheduling categories may lead to perverse incentives to frequently switch, in order to enjoy the lower of the local price or regional price. This would be at the expense of non-scheduled market participants.

In order to prevent this behaviour, the Commission is proposing that once a market participant opts change category (from scheduled to non-scheduled or vice versa), it would be prohibited from reversing this decision for a period of 12 months.

QUESTION 1: SCOPE OF DYNAMIC REGIONAL PRICING

Do stakeholders consider that the scheduled / non-scheduled distinction offers a sensible basis for determining which parties should face local or regional pricing?

Is the proposed waiting period of 12 months to reverse a change to a participant's categorisation workable and appropriate?

4.3 What network constraints will influence locational marginal prices?

BOX 5: CONSTRAINTS IN PRICING

Under the proposed approach to dynamic regional pricing, locational marginal prices would differ across the network when certain thermal and non-thermal transmission constraints arise.

To cause diverging local prices, these constraints must related to the shared network and be included in the NEM dispatch engine (NEMDE).

The NEM dispatch engine seeks to maximise the value of trade given the physical limitations of the power system. These physical limitations are otherwise known as 'constraints' and reflect, for example, the amount of electricity that can flow over a particular piece of equipment while preserving its integrity, safety and security.

Locational marginal prices represent the **marginal** cost of supplying an additional increment of energy demanded at a given **location**[29] in the transmission system. Without any binding shared network constraints or transmission losses, the cost of supplying an additional megawatt of electricity would be the **same** at all connection points. This is because:

- the same marginal generator could supply all connection points (since there is no congestion)
- the quantity of energy injected into the system would be the same as the quantity withdrawn (assuming no losses).

29 That is, transmission connection point or node.

However, if transmission constraints bind, the same marginal generator would no longer be able to supply all locations in the system. This is because the transmission constraint will restrict the amount of energy that certain generators can supply. For connection points located downstream of the constraint, an additional megawatt can now only be supplied by another, more expensive, generator. This means that the locational marginal prices at these connection points are now *different* due to the transmission constraint, resulting in a higher locational marginal price those located behind the constraint.

Only constraints that result in limitations on transmission flows on the shared network would lead to different marginal generators across the network, and in turn result in diverging local prices. This means that not all dispatch constraints will result in differences between locational marginal prices.

For example, constraints that relate to individual generators, such as limitations on their maximum or minimum output and FCAS provision, would not result in divergent local prices. These types of constraints will result in a more costly generator being marginal (and so setting the locational margin price) across the power system.[30] However, because the same marginal generator could supply all connection points, the locational marginal price is the same across the shared network.

There are a number of different types of constraints currently in the NEM dispatch engine that may impact on transmission flows within the power system:

- Thermal constraints are applied to prevent overloading of a particular transmission element (for example, a transmission line or transformer), either pre- or post-contingency.
- Transient stability constraints prevent pole-slipping of one or more generating units in the aftermath of a fault, which could damage the unit and would likely cause it to trip.
- Voltage stability constraints prevent voltage collapse in the aftermath of a contingency.
- Oscillatory stability constraints are designed to prevent a steady-state instability caused by undamped response to normal small perturbations occurring in the power system.
- System strength stability constraints are designed to maintain sufficient fault currents to ensure post-contingent stability and proper operation of protection systems.

The NEM dispatch engine is currently able to account for some transmission constraints better than others. This is because some dispatch constraints are more idiosyncratic in nature and thus difficult to model effectively. For example, we understand that system strength constraints are not represented in dispatch in the same way as other stability constraints due to their complexity.[31]

To the extent that certain dispatch constraints are currently excluded from the dispatch engine, then they do not impact the regional reference price. They would also not be factored in to locational marginal prices. Rather, AEMO must manage these physical

30 Which would lead to a higher regional price.

31 AEMO is only able to set a simple limit on aggregate asynchronous generation within NEMDE to ensure that the system has system strength stability.

constraints through a blunter method such as directions or instructions, with accompanying payments managed through the intervention pricing regime.

However, including all constraints that exist in the NEM dispatch engine in dynamic regional pricing sets this regime up to be flexible in the future. To the extent that there are new constraints in future (e.g. to do with system services) that can be incorporated in the NEM dispatch engine, then this will mean that dynamic regional pricing will account for them, as well as the payout from the financial transmission rights.

QUESTION 2: CONSTRAINTS IN PRICING

Do stakeholders agree with characterisation of the constraints that would be reflected in locational marginal prices?

4.4 How is the regional reference price calculated?

BOX 6: REGIONAL PRICING METHOD

The regional price would preferably be the volume weighted average price (VWAP) applicable to unscheduled demand and supply within the region.

In the June directions paper, we asked for stakeholders' views whether the current regional pricing would need to be changed in to accommodate dynamic regional pricing:

- AEMO's preferred approach was to implement full nodal pricing. This would remove the regional price, and instead have all forms of load and generation (i.e. all scheduled, semi-scheduled and non-scheduled market participants) paying their locational marginal price. Under this model, the current concept of NEM regions and the current arrangements of settlement occurring against a regional reference price would no longer be applicable.[32]
- Some stakeholders expressed a preference to retain the current pricing methodology, if possible, in order to minimise the complexity and cost of reform.[33]
- ENA provided conceptual support for adopting a volume-weighted average price, on the basis that it would better reflect the average marginal cost of electricity across the system.[34]

32 AEMO, submission to the directions paper, *Coordination of generation and transmission investment implementation- access and charging*, p. 1.

33 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, directions paper submissions: Mondo Energy, p. 5; Infigen, p. 7; Lighthouse Infrastructure Management, p. 7.

34 ENA, submission to the directions paper, *Coordination of generation and transmission investment implementation- access and charging*, p. 14.

4.4.1 Why we are not proposing full nodal pricing

The Commission agrees that moving to full nodal pricing may seem attractive from the perspective of economic efficiency, since it has the advantage of more accurately reflecting the costs of network congestion to all parties, including non-scheduled market participants. However, the Commission does not consider that such a change would be practical. Partly this is since a major downside is that it removes the regional reference price. The NEM's existing regional pricing model was designed to promote liquidity in forward contract markets by allowing all generators and retailers in a given region to trade with each other at the same market price.

The concept of a regional reference price facilitates contracting around a common wholesale market price at which all load and generation is settled. The ability of generators to sell forward contracts against their output allows them to hedge against the risk of spot price volatility, which increases financial certainty for investors. Ultimately, this should result in lower prices for consumers, with generators able to offer electricity (in both spot and contract markets) at lower prices than they otherwise would.

Therefore, our model does not propose moving to full nodal pricing. Rather, we maintain the concept of a regional price for the purpose of supporting liquidity in forward contract markets. If all load were to face a locational marginal price instead of a common regional price, there may be a risk of splitting liquidity in the contract market, as forward contracts would potentially instead need to be struck against different locational marginal prices. The Commission understands that, in overseas markets with locational marginal pricing, it is common for load to be priced at a common price.[35] This is in line with our proposal.[36]

However, while we do not consider that moving to full nodal pricing would be beneficial at this stage - it would be a significant change to the market - our approach provides the flexibility for this to be adopted in the future if it was deemed in the long-term interests of consumers. This means such a model could be pursued in the ESB's post 2025 work, for example.

4.4.2 Opportunity to review NEMDE

The introduction of dynamic regional pricing may present a timely opportunity to optimise dispatch processes through the development of systems that more accurately reflect real-time conditions in the NEM. AEMO flagged in their submission that there would be benefits in exploring how the existing NEM dispatch engine could be modified or enhanced.

NEMDE currently models the transmission system *indirectly*, through the use of constraint equations that maintain flows across the power system within pre-determined limits. This has a number of implications, including that load is not directly modelled at different locations within the system. Rather, load is assumed to sit at the regional reference node, with load location represented indirectly through dispatch constraints and loss factors.

35 For example, the ERCOT market in Texas and the PJM market in the north-eastern United States.

36 Of course, this is not the only option - some markets do have full nodal pricing on both generation and load side, such as New Zealand.

This did not present too many issues historically, given that the regional reference nodes were typically chosen to be close to where the majority of load was located. However, given the transition under way, this is likely to no longer be sustainable, particularly as integration of distributed energy resources continues and distribution networks move to two-way platforms.

We consider that the proposed introduction of dynamic regional pricing results in an opportunity to work with AEMO (as well as the other market bodies, the ESB and AER) to consider how the NEM dispatch engine may be evolved. For example, it could adopt a better calculation of regional pricing. We would work through ways in which each physical element could be *explicitly* reflected in the transmission system, including the location of load within the network. This would also result in more precise representation of the network.

This consideration could also be done in conjunction with the ESB's post 2025 work, since it would support an energy transition in a manner that is broader than the benefits being presented under the COGATI review. For example, a new NEMDE would include the following distinct benefits to the NEM:

- It would support the full range of market design options that may be considered under the ESB's Post-2025 Market Design review.
- It is consistent with the transition towards a two-sided market, including greater participation by the demand side.
- It is consistent with the AEMC's proposed work on moving to a grid of the future, including accommodating two-way flows across distribution networks.
- It would allow dispatch of the proposed interconnector, EnergyConnect, as an inter-regional loop.[37]

The benefits that would accrue to the proposed access model alone are explained further below.

4.4.3 What is volume weighted average pricing?

The regional reference price is currently calculated as the locational marginal price at a given regional reference node.

Ideally, our proposed model would use volume weighted average pricing. This involves calculating a locational marginal price[38] for all transmission connection points in the system. These prices would then be weighted according to the demand and supply of non-scheduled participants at different connection points.

Similar to the current pricing method, VWAP would produce one common regional price for non-scheduled market participants. However, the VWAP would not be anchored to a physical location in the way that the current regional reference price is anchored to the regional reference node. Instead, it would measure the average cost of electricity consumption and

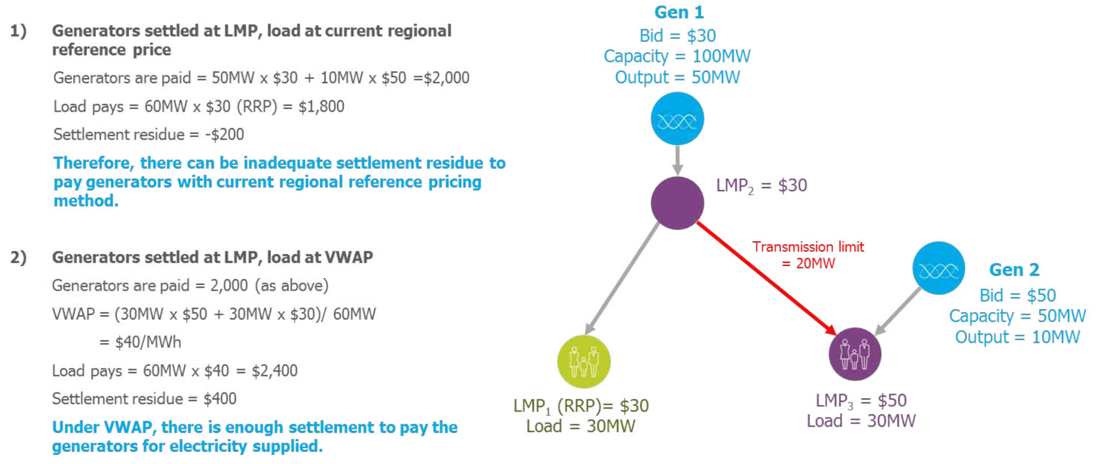
37 Our understanding is that the current NEMDE is not able to accurately dispatch a regional loop.

38 The underlying local prices would reflect the marginal losses between a connection point and the generator who is setting the local price at that point in time.

supply at a point in time, given patterns of non-scheduled demand and supply within the region.

A simple example of wholesale settlement under the current regional pricing method versus under VWAP is illustrated in Figure 4.1.

Figure 4.1: Wholesale settlement under the current regional pricing method and VWAP



Source: AEMC

4.4.4 Benefits of volume weighted average pricing

The Commission considers that ideally the model would use VWAP, since a key advantage of VWAP is that it would more accurately reflect underlying local prices than the existing regional reference price, which captures the local price at only one node in a region. This method is more flexible to future changes as the electricity system transforms, including moving to more active distribution networks.

Adopting a VWAP means that there would also always be sufficient money recovered from consumers to pay scheduled market participants who now receive their local marginal price. The money paid by load for wholesale electricity will be sufficient to cover the payments to generators for the supply of electricity.

Under VWAP pricing, there would be at least enough money coming in to wholesale settlement from scheduled and unscheduled load to pay:

- the regional price for each megawatt of electricity supplied by non-scheduled generation
- the local price for each megawatt of electricity supplied by semi-scheduled and scheduled generation.

Furthermore, the settlement revenue generated as a result of the transmission constraint is exactly the appropriate amount, in that it equals the differences in the local marginal prices between the nodes, multiplied by the flow on the line (which is equal to the limit of the line).[39]

In the example, above, the settlement residue is $400, which is equal to the flow on the constrained line (20MW) multiplied by the price difference between the nodes either side of the constrained line ($20/MWh).

The Commission is interested in stakeholder views on the proposal to adopt VWAP - for example, whether or not stakeholders agree with the proposed benefits, or are there other alternatives that could be explored. It is worth noting that if VWAP pricing was not adopted, then that would require other changes to be made to the proposed model for access reform in this document. As noted in the introduction, this is an internally consistent model. One such example is that if the current regional reference pricing method was to be retained under dynamic regional pricing, then there may not be enough money coming in from load to pay generators the amount owed to them under wholesale settlement arrangements in a given dispatch interval. This may occur when the regional reference price is lower than local prices at other transmission nodes, and there is a significant level of demand situated away from the regional reference node.

To ensure sufficient revenue, possible alternative solutions would be:

- to cap the local prices at the regional reference price (as currently formulated), or
- scale local prices down or uplift the regional reference price (as currently formulated).

At this time, our proposal does not include these approaches as our initial view is that they would dilute the benefits of more granular and accurate pricing signals that would occur under our proposed model. These benefits are particularly important in relation to large-scale storage locational decisions; as these parties have significant opportunity to benefit from more accurate pricing signals in relation to their investment decisions. We are interested in stakeholder views on these matters.

4.4.5 Implementation of volume weighted average pricing

As noted above, the current dispatch engine does not model load directly at different locations within the system. Consequently, it does not seem possible with the existing dispatch engine to determine the local price at existing non-scheduled load connection points. This is a clear pre-requisite of determining the volume weighted average price of non-scheduled load.

Adopting a volume weighted average pricing approach would therefore require at least some redevelopment of the existing NEM dispatch engine from the current 'hub and spoke' design.

The Commission's initial analysis indicates that this could lead to additional substantial dispatch efficiency gains by having dispatch processes more accurately reflect real-time conditions in the NEM, regardless of improving wholesale market price signals. We are

39 This is important for the design of financial transmission rights, discussed in Chapter 5. If the number of financial transmission rights sold is commensurate with the physical capacity of the system, then there is enough settlement residue to back financial transmission rights payments.

working with AEMO to explore the options for how the NEM dispatch engine could be modified, including indicative costs.

Such a change should result in more efficient dispatch outcomes, by allowing AEMO to map where *demand* is located at any given moment in the system. It would also allow for a more accurate and efficient representation of losses within the system (discussed further in section 4.5). We consider that this would set up the framework that would be more adaptable to the future. In particular, explicitly mapping demand across the system would allow locational marginal prices to be calculated for non-scheduled load, which is not currently possible in NEMDE.

Over time, the NEM is likely to transition towards a two-sided market as demand side resources become more responsive to wholesale market prices. As this transition progresses, the advantages of allowing non-scheduled market participants to face a locational marginal price will increase. The proposed approach to establishing a common regional price provides flexibility to move to locational marginal pricing for non-scheduled participants over time, if this was found to be in the long-term interest of consumers.

QUESTION 3: REGIONAL PRICING METHOD

Do stakeholders agree with characterisation of the benefits and costs of moving to a volume-weighted average price?

What other costs and benefits do stakeholders think should be taken into account?

4.5 Are loss factors included in wholesale electricity prices?

BOX 7: LOSSES UNDER DYNAMIC REGIONAL PRICING

Wholesale electricity prices (including locational marginal prices and the regional price) will include dynamic loss factors. These dynamic losses would replace the current approach to calculating inter- and intra-regional losses.

Electricity transported across the transmission system is subject to losses. That is, if demand at one connection point is supplied by generation at another connection point, the quantity of generation produced needs to exceed that demand, in order to account for losses as electricity flows between the two locations. This means that it is more expensive to supply demand with generation located in different parts of the network away from load.

4.5.1 Current arrangements

Transmission losses are currently factored into dispatch through the application of marginal loss factors:

- **Losses that occur within a region ('intra-regional losses') are modelled as static and are set each year**

  AEMO calculates intra-regional loss factors using the weighted average of the forecast actual marginal loss factors that would arise in dispatch over the year.

- **Losses that occur between regions ('inter-regional losses') are calculated quasi-dynamically in dispatch**

  The calculation of inter-regional losses might be described as quasi-dynamic. This is because the inter-regional losses calculated in dispatch vary dynamically with flows on the system. However, the linear loss function is itself static and set on an annual basis by AEMO.[40]

Marginal loss factors exist to improve the efficiency of wholesale electricity pricing and dispatch outcomes. This is because adjusting generator offer prices to account for loss factors recognises the impact of losses on the marginal cost of delivering energy from generation sources to where demand is located. In this way, dispatch minimises the total cost of supply by effectively co-optimising the cost of generation and the cost of the associated transmission losses.

The Commission is currently considering rule change requests from Adani Renewables to change the current approach to calculating marginal loss factors. A draft determination will be published by 21 November 2019. The *Transmission Loss Factor* rule change process is focussed on the transmission loss factor framework in the context of the current framework. Since this review is focussed on holistic longer-term solutions to the transmission access framework, the Commission is considering loss factors more broadly in the COGATI review.

4.5.2 Dynamic loss factors

Under dynamic regional pricing, the Commission proposes that intra-regional and inter-regional losses would be dynamically calculated in dispatch.

Actual marginal losses vary dynamically, depending on flows on the transmission network. Therefore, there will naturally be some dispatch inefficiency arising from differences between actual marginal loss factors and the assumed (static) marginal loss factor. Intuitively, if we assume that the static loss factors represent an unbiased estimate of the mean value of MLFs, the degree of inefficiency is likely to be proportionate to how much loss factors vary from the average on a thirty-minute by thirty-minute basis.[41]

The Commission notes that there are several trends that may be contributing to increasing variance in actual loss factors, related to the de-carbonisation of the grid and associated increase in more variable and flexible supply and demand-side resources. For example, increased volatility in output of generators could be expected to increase the volatility in actual marginal loss factors.

40 The loss function is a linear approximation of the quadratic loss function applied to estimate marginal losses based on the quantity of energy flowing between regions.

41 Soon to be a five-minute by five-minute basis, with the implementation of five minute settlement in 2021.

Further, the number, size and use of interconnectors within the NEM is expected to increase. Taken together, the increase in grid interconnectedness alongside the rise in variable renewable generation may lead to more frequent reversals of flow direction along and near interconnector routes (as clusters of generation turn on and off in response to weather patterns). This trend would, in turn, potentially change whether the actual marginal loss factors for associated nodes are greater or less than one[42], which may further increase volatility in the annually set loss factors over time.

The benefits that accrue from adopting dynamic loss factors largely relate to more efficient dispatch. For example, if the static marginal loss factor is very different from the actual marginal loss factor in any given dispatch interval, this could lead to generators with higher loss-adjusted costs being dispatched ahead of lower cost generators. If intra-regional losses were modelled dynamically in dispatch, the productive efficiency of the dispatch engine could be improved.

However, we recognise that moving to dynamic loss factors could potentially increase volatility of loss factors. Generators today are expressing concerns with the increased volatility in their annual marginal loss factors from year to year. Therefore, we consider it important to combine the introduction of dynamic loss factors with the introduction of a product that will hedge generators against changes in loss factors. This is discussed further in Chapter 5.

4.5.3 Implementation of dynamic loss factors

The specification assumes that dynamic loss factors would be incorporated into dispatch in real time. Our current understanding is that a real-time approach to dynamic loss factors would require a redevelopment of the existing NEM dispatch engine as discussed above in section 4.4.2.

Currently NEMDE does not explicitly model transmission losses that occur within a region. This would need to be changed to simulate losses on each branch of the transmission network, to reflect how the level and cost of transmission losses would change as the branch flow changes. This could be considered similar to the approach taken in the NEM dispatch engine for modelling inter-regional losses. Such an approach has been adopted in other jurisdictions where dynamic loss factors are part of the dispatch process, such as in the New Zealand electricity market.

There may be other options to incorporate dynamic loss factors in dispatch. For example, intra-regional marginal loss factors are currently set on an *ex ante* basis, a year ahead. It might be possible to adopt an *ex ante* approach in which marginal loss factors are calculated close to real time for each dispatch interval, to reflect expected network conditions (for example, 30 minutes before dispatch).

The resulting marginal loss factors would then be incorporated in dispatch processes in the same way as for static marginal loss factors currently. While such an approach could in

42 This would change whether the price at the node is greater or less than the regional reference price.

theory be implemented without significant revisions to the NEM dispatch engine, this type of modification would still require new interfaces and data transfers occurring close to real time.

As noted above, we are working with AEMO to explore the options for this to occur, including indicative costs.

QUESTION 4: LOSSES UNDER DYNAMIC REGIONAL PRICING

- Do stakeholders agree with the Commission's qualitative analysis of the potential dispatch efficiency benefits that could result from adopting dynamic loss factors?
- What other costs and benefits do stakeholders think should be taken into account?
- Do stakeholders agree that the alternative *ex ante* approach to incorporating dynamic loss factors should not be pursued further at this stage?

4.6 How are issues of market power dealt with?

BOX 8: MITIGATING MARKET POWER

Under the proposed approach to dynamic regional pricing, market power issues may not arise, however, if they do:

- An ex ante offer cap would be introduced in the event that a generator was deemed to be pivotal.
- The offer cap would be set at a value related to the conditions in the wholesale market at the time the cap is applied.
- In addition, the AER should review its existing wholesale market monitoring functions and processes with the potential to introduce more stringent provisions in the event of a material problem.

Some stakeholders have raised concerns that the introduction of dynamic regional pricing could potentially give rise to new circumstances where participants are able to manipulate the wholesale market prices above their long-run willingness to pay or sell electricity.[43] These stakeholders have argued that this could occur because allowing prices to vary across the network effectively creates smaller 'sub-markets' when transmission constraints bind, and the degree of concentration in these sub-markets may mean that competition does not provide an effective constraint on bidding behaviour.

The Commission does not envsiage that market power will be increased as a result of these reforms. However, in recognition of stakeholder concerns we are intending to undertake some modelling - as discussed in Chapter 7 - to quantify the potential for additional market

43 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, directions paper submissions: AER, p. 1; HRL Morrison & Co, p. 3; Aurizon Networks, p. 3; Meridian and Powershop, p. 8; Energy Queensland, p. 6; Snowy Hydro, p. 2.

power issues to arise under dynamic regional pricing. This will help determine how material this concern may be. The incidence of new market power will be a function of when and where transmission constraints bind, and the resulting market structure 'behind' the constraints.

Ideally, market power mitigation mechanisms would not be needed. However, in the case where market power mitigation strategies are necessary, we have included some recommendations below.

We set out below:

- considerations of market power under current arrangements
- how this could change under dynamic regional pricing
- preferred market power mitigation strategies if they are deemed necessary.

4.6.1 Influencing outcomes under current arrangements

Generators use bidding strategies to influence how much they are dispatched for, and when they are dispatched, in the wholesale market. Transient pricing power, resulting in occasional spot price spikes, is an inherent feature of a workably competitive wholesale market. It is only a concern if it occurs frequently enough and to a significant enough magnitude to lead to average annual wholesale prices above the long-run marginal cost of generation.

It is important to note that the wholesale cost of electricity is not solely a function of current supply and demand conditions, but is also influenced by the forward contract market. Specifically, the prices for electricity in forward contracts smooth the costs and revenues associated with more volatile supply conditions, and change the incentives of market participants to bid into the wholesale spot market.

The AER has wholesale market monitoring powers, and notes that there are multiple ways that market power can arise within the NEM. The AER distinguishes between market conduct and the misuse of market power. Instances of non-competitive market conduct include (but are not limited to):[44]

- the extent of any physical withholding of capacity in the market
- the extent to which participants may have engaged in economic withholding, for example by shifting capacity to extreme high prices
- the extent to which participants are rebidding capacity from low to high prices close to dispatch, which can limit competitive responses from other generators.

4.6.2 Influencing outcomes under dynamic regional pricing

We do not envisage that dynamic regional pricing would increase the circumstances in which market participants may be able to manipulate the *regional* price. As under the status quo, we consider that groups of generators may be able to exhibit non-competitive market conduct if they can act to increase the long-run average regional price to a level that exceeds their long-run marginal cost (LRMC). This will be possible if the market has relatively few

44 AER, *Wholesale electricity market performance monitoring*, Statement of Approach, March 2018, p. 14

firms and has material barriers to entry. There are existing ways to mitigate this, which we consider are fit-for-purpose.

However, stakeholders have raised concerns about circumstances where market participants could influence the *local* price. This is because allowing prices to vary within each region effectively creates smaller 'sub markets' where transmission constraints bind, and the degree of concentration in these sub markets may mean that competition does not provide an effective constraint on bidding behaviour.

We consider that this should not often occur, due to:

- that market participants' relationships with the contract market may act to curtail any opportunities and incentives to exercise market power.
- that the coincidence of load pockets and limited competition is not likely to be widespread throughout the NEM.

On the first point, market participant will typically strike contracts in the forward market in order to mitigate their operating risks. These contracts will, in turn, influence their bidding strategies going forward. We consider that forward market contracts may depress the incentives that scheduled and semi-scheduled market participants have to exercise market power.[45]

4.6.3 Market power mitigation measures

The Commission's initial view is that a form of *ex ante* mitigation may be appropriate if a market power mitigation mechanism is deemed necessary. In addition, we consider that the AER should review its existing wholesale market monitoring functions and processes, with the potential to introduce more stringent provisions in the event of a material problem.

This is consistent with the findings in other jurisdictions that have implemented more granular pricing signals (as summarised in Appendix C).

Mitigation measure one: introduce an ex ante offer cap in the event that a generator is deemed to be pivotal[46]

This approach is a bid mitigation mechanism, whereby a regulated offer price cap is automatically applied through dispatch if a generator fails a pivotal supplier test.[47] The test is a market power test, and the regulated price applied would be determined with regard to the prevailing market conditions. If the cap is a mechanical calculation, then the Commission considers that the cap would be determined by AEMO and applied in practice automatically through the NEM dispatch engine. This is appropriate since it leaves the AER to undertake wholesale market monitoring.

45 For example, a common contract is a swap. Under swaps, the generator will receive the strike price in the contract when the wholesale spot prices are below the strike price; however, it will need to pay the buyer the difference between the spot price and the strike price for the contracted quantity when the spot price is higher than the strike price. Therefore, even under dynamic regional pricing, a generator with a cap may have limited incentives to increase the local price, since it will have to pay out under its contract if that occurs.

46 This approach is currently used in the ERCOT market.

47 A pivotal supplier test could be, for example, if the generator is required to meet demand at one or more transmission nodes.

The main benefit of this option is that it would create a clearly defined outcome. This could potentially operate as a relatively automatic process, which reduces compliance costs; although the effects of the mechanism would likely themselves require careful monitoring.

In addition, we consider that this approach is broadly consistent with our current approach to intervention pricing, whereby AEMO has a transparent pricing methodology that it uses to provide payments to generators that are directed on to meet reliability needs. Under the current arrangements, these generators are more likely to be monopoly providers in a load pocket area. Under dynamic regional pricing, oligopolistic generators in load pockets will also be incentivised to bid above their costs. An ex ante offer cap would need to be designed to cover both of these instances.

The exact nature of the cap still needs to be thought through. A key challenge with this approach would be designing an offer cap that avoids the risk of disrupting investment signals or preventing generators from recovering efficient costs.

The Commission's preference is the offer cap should be set at a value related to the conditions in the wholesale market at the time the cap is applied. For example, the cap could be set at the price of the second highest bid in the wholesale market, with this made by another generator who was cleared.

The Commission considered alternative options, but on balance does not think they would be as appropriate, because they would be less reflective of the prevailing market dynamics. These options include:

- A pre-determined value, related to costs of the generator. The cap cannot be set at the short run marginal cost, since we need generators to recover long-run costs. This could take a similar approach to what the Commission recommended in our *Investigation into the intervention mechanisms in the NEM* review.[48]
- A fixed $/MW. The cap could be set at a fixed $/MW, although, this would risk over compensating some generators and under compensating others.

The cap would only apply when constraints bind and a generator is deemed pivotal. If this occurs, then the cap will be automatically applied.

The Commission notes that it ruled out introducing a pivotal supplier test in its final report on Gaming in rebidding.[49] The Commission still considers that, in the absence of changes to market design such as DRP, this should not be introduced in the NEM. However, given the specific concern raised by stakeholders, the Commission considers that an ex ante offer cap could be introduced alongside dynamic regional pricing.

Mitigation measure two: the AER should review its existing wholesale market monitoring functions and processes, with the potential to introduce more stringent provisions in the event of a material problem

As a consequence of the reforms, the AER should review its monitoring functions and processes to make sure they are fit for purpose for coping with dynamic regional pricing. The

48 AEMC, *Investigation into intervention mechanisms in the NEM*, Final report, 15 August 2019, p. 40.

49 AEMC, *Gaming in rebidding*, Final report, 28 September 2018

new procedures should aim to ensure that the AER is able to detect if unforeseen or new instances of market power arise following the introduction of the new pricing regime.

For example, an ex ante offer cap would not cover situations where demand side participants were able to exert market power. It is unlikely that this will be a problem in the short term, but t may materialise over time if the amount of storage and/or scheduled load increases significantly.

QUESTION 5: MITIGATING MARKET POWER

- Do stakeholders agree with our characterisation of how market power issues may arise under dynamic regional pricing?
- Do you agree with our proposed response to market power issues?
- What other costs and benefits may result from this response to market power issues?

5 FINANCIAL TRANSMISSION RIGHTS

The second element of our proposed model aims to improve the financial risk management options for market participants. We are proposing to enable scheduled and semi-scheduled market participants to better manage the risks of congestion and transmission losses by purchasing financial transmission rights (FTRs).

Financial transmission rights pay out on the price differences that arise due to dynamic regional pricing, allowing market participants to manage the risk of transmission constraints and losses.

This chapter discusses how these financial transmission rights will be designed, with the following chapter describing how they will be procured.

5.1 Summary of key design features

The following table provides the proposed specification for financial transmission rights for stakeholder feedback.

Table 5.1: **Summary of key design features for the financial transmission rights**

ISSUE	PROPOSED DESIGN CHOICE
What type of financial transmission rights are offered?	The type of financial transmission rights that would be offered would be option instruments, which only ever result in a positive payment. This means that the financial transmission right would never result in a payment liability for the right holder.
What prices do the financial transmission rights refer to?	Market participants would be able to buy financial transmission rights that pay out on the price difference between: • a local price and any regional price • a regional price and any other regional price.
When do the transmission rights pay out?	Market participants would be able to acquire rights which pay out: • at all times of the day ('continuous rights'), or • at specific pre-defined times of the day ('time of use' rights).
Where does the revenue to back the transmission rights come from?	The source of revenue to back financial transmission rights would arise from the difference between what generators are being paid and load is paying under dynamic regional pricing. Excess settlement residues in a given time period would accumulate in a fund administered by AEMO. This would be drawn down from when there is insufficient settlement

ISSUE	PROPOSED DESIGN CHOICE
	residue in a different time period. When the fund is exhausted, FTR payouts would be scaled to the extent necessary.
How are losses hedged?	Financial transmission rights should hedge the risk of price differences arising from losses. Specific details of these instruments is yet to be determined.

The following sections discuss these elements of the design specification in greater detail. We are interested in stakeholder feedback on any and all the design features described below.

It should be noted that the majority of discussion relates to financial transmission rights that pay out on the price differences that arise as a consequence of **congestion** on the shared network, as opposed to **losses**. FTRs to incorporate losses have some unique complexities, which may drive specific design decisions.[50]

The Commission's approach to non-thermal constraints is discussed in section 5.6. In short, The financial transmission rights would hedge the full price difference between nodes, including those price difference arising from non-thermal constraints.

5.2 What type of financial transmission right would be sold?

BOX 9: TYPE OF FINANCIAL TRANSMISSION RIGHTS

The type of financial transmission rights that would be offered would be option instruments, which only ever result in a positive payment.

This means that the financial transmission right would never result in a payment liability for the FTR holder.

Two simple types of financial transmission rights that could be offered are options or swaps.

5.2.1 What are options?

The Commission proposes that the financial transmission rights that are offered should be option instruments. An option right would mean that the payout under the financial transmission right is only ever positive.

For example, if a generator has purchased an option that pays out on the difference between its local price and the regional price:

50 The design of FTRs for losses is discussed further in section 5.7.

- the FTR would pay a positive amount to the generator when its local price was below the regional price[51]
- the FTR would not pay out when the local price was above or equal to the regional price.

For each pair of prices, two option products would be available. Each financial transmission right would be backed by the same transmission capacity, but relate to opposite 'directions' of electricity flow in the network. For example:

1. the first financial transmission right might pay out when the local price is lower than the regional price[52]
2. the second financial transmission right might pay out when the regional price is lower than the local price.[53]

The rationale for having option FTRs in both 'directions' is to accommodate the differing needs of the supply and load side of the market. The first 'direction' above is likely to be useful for scheduled and semi-scheduled generators, who are likely to want to hedge against relatively *low* LMP. The second 'direction' is likely to be useful for scheduled loads, who are likely to want to hedge against relatively *high* LMP.

BOX 10: OPTION INSTRUMENTS

Financial transmission rights for generation

Financial transmission rights that are likely to be useful for generation would be 'put' options. That is, they would pay out when wholesale electricity market has a local ('spot') price that is below the regional ('strike') price. The financial transmission right is 'out of the money' otherwise, and would not be exercised.

The mathematical pay out of the financial transmission right would therefore be:

FTR payout= max(0, VWAP - LMP).

Financial transmission rights for load

Financial transmission rights that are likely to be useful for load would be 'call' options. That is, they would pay out when wholesale electricity market has a regional ('strike') price that is below the local ('spot') price. As above, the financial transmission right is 'out of the money' otherwise.

The mathematical pay out of the financial transmission right would therefore be:

FTR payout= max(0, LMP - VWAP).

Financial transmission rights which hedge the price difference between two regions are described in section 5.3.2.

51 The payout would be equal to the difference between the regional price and the local price, multiplied by the FTR amount purchased.

52 That is, FTR payment = max(0, VWAP - LMP)

53 That is, FTR payment = max(0, LMP - VWAP).

5.2.2 What are swaps?

The Commission does not favour the use of swap instruments at this time to support dynamic regional pricing.

A swap instrument would simply pay out on the difference between prices. This means that FTR 'payments' could be positive or negative.

For example, if a generator has purchased a swap that pays out on the difference between its local price and the regional price:

- the FTR would pay a positive amount to the generator when its local price was below the regional price[54]
- the FTR would require payment from the generator when the local price was above or equal to the regional price.[55]

Some overseas markets with financial transmission rights offer both swap and option instruments, including New Zealand, ERCOT and PJM. Our understanding from the New Zealand market is that the swaps are rarely purchased.[56] This may reflect the fact that market participants may not want to pay for a financial instrument that includes a liability.

Swaps would also require the development of prudential arrangements, given that FTR owners would be required at times to make payments into settlement. Introducing swaps would therefore create additional complexity into the market design, for apparently little value.

We consider that swaps could be subsequently introduced into the market if participants considered them to be of sufficient value.

QUESTION 6: TYPE OF FINANCIAL TRANSMISSION RIGHTS

1. Should financial transmission rights be limited to options instruments?

5.3 What prices do the financial transmission rights refer to?

BOX 11: THE PRICES THAT THE FINANCIAL TRANSMISSION RIGHTS REFER TO

Market participants would be able to buy financial transmission rights that pay out on the price difference between:

- a local price and any regional price

54 The payout would be equal to the difference between the regional price and the local price, multiplied by the FTR amount purchased.

55 The payment required would be equal to the difference between the local price and the regional price, multiplied by the FTR amount purchased.

56 See, for example: https://www.ea.govt.nz/dmsdocument/22503-overview-of-the-ftr-market, p. 5.

- a regional price and any other regional price.

The FTRs between two regional prices would replace the current inter-regional settlement residue auction (SRA) distribution units that are periodically auctioned off.

5.3.1 Financial transmission rights between local and regional prices

As discussed in section 5.2.1, we are proposing financial transmission rights that are useful to both demand and supply side participants (i.e. load and generation) to manage the price difference between their local node and a regional price.

FTRs would therefore be available which relate to the difference between a nominated local price and any regional price (and vice versa). By relating to the difference between a local price and any regional price, financial transmission rights would allow market participants to manage the basis risk introduced by dynamic regional pricing.

Potential to support liquidity

The proposed design is for non-scheduled market participants to continue to be settled at their regional price. This choice has been made, in part, for the purpose of supporting liquidity in forward contract markets. If all load were to face a locational marginal price instead of a common regional price, there may be a risk of splitting liquidity in the contract market, as forward contracts would potentially instead need to be struck against different locational marginal prices.

The design of financial transmission rights is consistent with this proposal, and should go further to *improve* the liquidity of forward contract markets. This is because financial transmission rights would allow scheduled and semi-scheduled market participants to manage transmission congestion risk more effectively than they can under the current arrangements.

Under current arrangements, scheduled and semi-scheduled market participants risk being constrained off as a result of transmission constraints.[57] These participants are not directly compensated when this occurs. For generators, their revenue in the spot market is simply the energy dispatched multiplied by the regional reference price and the marginal loss factor; therefore, a reduction in physical dispatch necessarily reduces their revenue.

If a generator takes a contractual position in the wholesale contract market, it may suffer a loss when it is constrained off. This is because the revenue generated through the spot market is not sufficient to defend its wholesale contract position. Transmission congestion can be a material risk, as congestion typically happens when demand is high, which is also when the spot price is typically high.

57 For generators, this means not being dispatched or being dispatched at a lower quantity than is preferred, despite offering at a price less than the regional reference price. For scheduled load, this means not receiving the quantity of energy bid for, despite offering at a price above the regional reference price.

To manage the risk of congestion, generators currently sell a lower amount of hedges in the wholesale contract market than their physical capacity.[58] We understand that generators do this in practice. For example, thermal generators typically only contract 75 per cent of their capacity or expected output.[59]

Financial transmission rights should alleviate the risk of congestion for their holders and improve their ability to offer contracts in the forward market.[60] Transmission FTRs do this by allowing scheduled and semi-scheduled market participants to access the regional reference price regardless of their physical dispatch. As such, market participants with financial transmission rights should no longer face the (material) risk that they are short in their wholesale contracts if they are constrained on or off.

In contrast, those that do not hold sufficient FTRs will be exposed to the local price and not receive a FTR payment. They will bear the risk of congestion that arises on the network.

Flexibility in design

To be clear, a market participant would have the option to buy an FTR that relates to their local price and the price of a region in which they are not located. This is to reflect the fact that a market participant may be electrically 'closer' to the regional price of a region other than the one they are located in.[61]

For example, a scheduled or semi-scheduled generator in south-west New South Wales may have a local price that more closely approximates the regional price of South Australia. In the proposed arrangement, this market participant may choose to enter into commodity contracts with counter-parties settling on the South Australian regional price, in part because the risk of transmission congestion (and the cost of a financial transmission right to address that risk) may be relatively low.

Market participants settled at their local marginal price would therefore be agnostic to the regional boundaries: they would be able to buy financial transmission rights from their transmission connection point to any regional price.

5.3.2 Financial transmission rights between regional prices

Market participants would also be able to buy FTRs that payout on the difference between any regional price and any other regional price, even if those regions are not adjacent.

However, that is not to say that the prices of inter-regional financial transmission rights will be roughly equivalent. Financial transmission rights between regions that are electrically far away from each other (e.g. Queensland and Tasmania) are expected to be relatively more

58 That is, they take a deliberately longer position, because of the downside risk of being short if congestion arises.

59 Although this behaviour also mitigates the risk of generator outages and so cannot be fully attributable to the risk of transmission congestion.

60 The retailer reliability obligation may also increase demand for contracts and, all else equal, increase their supply. But in entering into additional contracts, generators will still face the risk of transmission constraints.

61 And hence they may have a local price that relates more closely to the alternate regional price rather than the price of the region they are in.

expensive than FTRs that relate to two points that are closer together. This is appropriate given that the financial transmission rights relate to the physical capacity of the system.

Settlement Residue Auction units

The Commission envisages that the FTRs between regional prices would replace the existing inter-regional settlement residue products (colloquially known as SRA units). The need for, and design of, transitional arrangements for SRAs are discussed in Chapter 6.

Since AEMO will manage the residues going forward through the settlement process, this should improve the ability of TNSPs to better manage year-to-year cashflows arising from managing SRAs funds. This benefit is offset by AEMO having to manage the settlement residue instead.

Potential to support liquidity

Currently, liquidity is already somewhat split in the NEM across the five regions. Generators and market customers are somewhat unwilling to enter into wholesale hedges where each counter party is exposed to different regional prices. This is because of the basis risk that arises for each market participant if transmission constraints bind between regions and so the regional prices differ.

The use of inter-regional settlement residue auctions partially offsets this risk. However, SRAs are currently not firm in nature (due to the inclusion of transmission losses and effects such as counterprice flows).

Therefore, they constitute imperfect hedges, which means that they are more typically purchased by speculators in the market, rather than market participants for the purpose of basis risk management. Consequently, generators and market customers generally tend to contract with counter parties within their region.

We consider that the introduction of inter-regional financial transmission rights - that replace SRAs - will further support liquidity. Market participants will be able to buy financial transmission rights which hedge:

- the price difference between their local price and any regional price, including the regional price in other regions, or
- the price difference between any two regional prices.

These FTRs should be firmer than the existing SRA units, and hence improve the ability for market participants to manage pricing risk across regions. In turn, this should promote cross-regional trade, and improved liquidity in the existing regional markets. The reason why these financial transmission rights are expected to be firmer than the existing SRA units is discussed in box 14 in section 5.5.2.

QUESTION 7: LIQUIDITY

Do stakeholders agree with our characterisation about how the financial transmission rights should support liquidity?

5.3.3 Alternative approaches not proposed

There are a number of alternative approaches to financial transmission rights that were considered by the Commission, but are not proposed to be adopted.

A financial transmission right that relates from a local price to another local price

It is possible to sell financial transmission rights that relate to the difference between any local price and any other local price. This is a more granular approach than that currently favoured by the Commission.

This approach might be useful, for example, if a scheduled load and a scheduled or semi-scheduled generator wanted to enter into a commodity contract based on a price other than a regional price. They might do this if they are co-located behind a constraint that typically binds, meaning that their local prices are often similar. In this case, the price of a financial transmission right that managed any residual basis risk between the two local prices would presumably be lower than the price of a financial transmission right that related to the regional price.

The rationale for excluding any-to-any financial transmission rights is that it dramatically increases the number of possible FTRs that would be offered in an auction (from hundreds to tens of thousands). In turn this increases the complexity of the auction for allocating the FTRs, and increases concerns about the level of competition in the auction. It may also split liquidity in the secondary market for capacity.

Financial transmission rights that relate to a few pre-defined 'hubs'

The Commission is also aware of an approach whereby FTRs can only be bought between a (small) number of pre-selected transmission connection points. This is the approach taken in the New Zealand market.

In New Zealand, financial transmission rights can be bought and sold between eight pre-defined transmission nodes (known as 'hubs'). While this may increase competition and liquidity in the FTR market, it leaves market participants with the risk of any remaining price difference between their local node and the hub price. The Commission does not consider that leaving market participants exposed to this basis risk, with no way to manage it, would be efficient.

QUESTION 8: PRICES THAT CAN BE HEDGED

1. Have we appropriately identified the pairs of prices that can be hedged through the instruments?
2. Would more or less flexibility than that recommended be preferred?

5.4 When do the financial transmission rights pay out?

> BOX 12: WHEN THE FINANCIAL TRANSMISSION RIGHTS PAY OUT
>
> Market participants would be able to acquire financial transmission rights which pay out:
>
> - at all times of the day ('continuous rights'), or
> - at specific pre-defined times of the day ('time of use' rights).

5.4.1 Continuous rights

A continuous right would be active at all times of the day or night. It would payout the difference between the relevant prices in the financial transmission rights, whenever this price difference is positive.

Benefits of continuous rights

The main advantage of continuous rights (compared to the alternatives considered below in section 5.4.3) is that they are simple and generic. This makes them more fungible, easier to sell through the auction and so more conducive to liquidity in the secondary market. We consider that a key benefit is that counter parties would be able to more readily understand the FTR that they are buying, and the generic nature of the FTRs is likely to increase the prospective pool of buyers and sellers.

Drawbacks of continuous rights

A drawback of continuous rights is they may not be the best instruments for some market participants, particularly VRE participants, to manage the risk of congestion. Whenever the quantity of FTRs owned by the market participants is different from the *preferred output* of the market participant,[62] the FTR will pay out more or less than is required.[63]

For example, a continuous financial transmission right will pay out when:

- the generator is unavailable
- if the generator's preferred output is zero because the regional price is less than its short run costs.

In either case, the generator may receive a FTR payout despite the fact that - had that congestion not occurred - its output and revenue would have been zero. Therefore, continuous rights introduce an *upside* risk for generators.[64]

In turn, some generators may choose to manage this upside risk by simply purchasing less financial transmission rights than their maximum capacity (in order to avoid the upfront cost).

62 That is, the output that the market participant would have chosen absent of constraints.

63 For ease of explanation, throughout this section the term preferred *output* is used and a focus is placed on scheduled and semi-scheduled generators. Preferred *consumption* would be the appropriate term for scheduled load.

64 That is, where the financial transmission rights pay out in excess of that required to make the generator indifferent to the presence or absence of the transmission congestion.

This outcome would be less than ideal, as it would necessarily introduce *downside* risk for the generator. That is, the financial transmission right may no longer be sufficient to optimally hedge against transmission congestion when the generator's preferred output is high.

Of course, there may be some correlation between the generator's preferred output and instances of transmission congestion. Consider, for example, a wind farm located near many other wind farms. If it is not windy, the preferred output of all the wind farms is low,[65] meaning that there is unlikely to be transmission congestion. Conversely, the preferred output of each individual wind farm may be high when it is very windy; however, if the transmission capacity in that part of the network is not able to accommodate all the wind farms, then there is likely to be transmission congestion.

5.4.2 Time of use rights

We have recommended also selling time of use rights in order to partially address the concerns described above. Time of use rights would only be active (i.e. only pay out) at certain pre-defined times of the day (or night).

Time of use rights may be particularly useful for some forms of variable renewable generators.

For example, there is likely to be a high correlation between a solar generator's preferred output and the time of day when it needs to mitigate against transmission congestion. Further, this approach may result in positive consequences for other types of market participants.

We expect that solar generators will exclusively purchase time of use financial transmission rights that are active during daylight hours; which should allow additional FTRs (at a potentially lower price) to be released during the night-time. Depending on the circumstances, this may send an (appropriate) locational signal to other forms of generation (such as batteries or wind farms) to locate in this part of the transmission network.

5.4.3 Alternative approaches not proposed

It is important to acknowledge that time of use rights only partially address the concern that the FTRs available do not perfectly correlate with a market participant's preferred output or consumption.

The Commission explored more sophisticated, bespoke products to better correlate the products sold with generators' risk management needs. For example, one possible instrument that could be offered is dependent on weather patterns (i.e. it is only active when it is windy).

However, we consider that such instruments are likely to dramatically increase the complexity of the FTR procurement process. As discussed in section 6.2, the Commission is proposing an

65 In this context, 'preferred output' means the output of that the wind farm would have chosen given the price *had there been no transmission constraints*. The wind farm owner may have preferred it to be windier; however, availability risk is not a risk that can be hedged through the financial transmission right framework.

auction which would determine the appropriate combination of financial transmission rights to sell, given the bids made by market participants and the physical capacity of the system.

Bespoke products make this process far more complicated, because the auction would have to assess the variable nature of the active quantity of each of the products, in order to ensure that the active quantity can be simultaneously accommodated by the physical system.

It may also be the case that, in time, an active secondary market emerges that allows market participants to acquire bespoke products. That is, a market participant may purchase a continuous FTR and then on-sell a bespoke product on the secondary market. This would leave the primary seller with a financial transmission right which is better correlated with its preferred out. Its counter-party would also have acquired a bespoke FTR, presumably suited to its needs.

Were such a secondary market to emerge, this would reduce the need for bespoke products to be sold in the primary market, because market participants would be able to acquire them on the secondary market instead.

QUESTION 9: WHEN FINANCIAL TRANSMISSION RIGHTS ARE ACTIVE

1. Are continuous and time of use rights appropriate, given the trade-offs identified above?
2. Are more bespoke products desirable through the auction, and how might they be accommodated?
3. What are your expectations of a secondary market emerging to provide bespoke products, if desired by the market?

5.5 What is the source of revenue to back the financial transmission rights?

BOX 13: THE SOURCE OF REVENUE TO BACK THE FINANCIAL TRANSMISSION RIGHTS

The source of revenue to back financial transmission rights would be the settlement residue that arises from the difference between what generators are being paid for energy and load is paying for energy.

The number of FTRs sold is expected to be set so there will likely be excess settlement residue not required to pay financial transmission rights in any given dispatch interval. This would accumulate in a fund, which would be drawn down on the relatively rare (but potentially material in dollar terms) instances when a shortfall in settlement residue arises. This fund would be administered by AEMO.

When the fund is exhausted, FTR payouts would be scaled to the extent necessary.

The source of revenue used to back the financial transmission rights will come from settlement residue that arises because supply and demand is being settled at different prices under dynamic regional pricing.

Payments to FTR holders will commonly not *exactly* equal the settlement residue that arises on a dispatch interval by dispatch interval basis. Excess settlement residue[66] would accumulate in a fund, which would be drawn down when a shortfall in settlement residue arises. This fund would be administered by AEMO.

This section discusses:

- how settlement residue arises under dynamic regional pricing
- that this settlement residue will be used to back financial transmission rights
- why settlement residue does not exactly equal FTR payouts on a dispatch interval by dispatch interval basis
- Commission's preferred approaches to making sure there is sufficient revenue to back the FTRs.

The section will also explain why the Commission does not favour the use of the revenue generated from the sale of FTRs to supplement the fund when settlement residue is exhausted.

This section is focused on FTRs that payout on the differences in prices arising due to transmission congestion, as opposed to losses. FTRs for transmission losses are discussed in section 5.7.

5.5.1 Congestion settlement residues

As discussed in Chapter 4, in the absence of binding dispatch constraints or transmission losses, the cost of supplying an additional megawatt of electricity would be the same at all connection points within a region. This is because:

- the same marginal generator could supply all connection points
- the quantity of energy injected into the system would be the same as the quantity withdrawn.

When there is a binding transmission constraint, the same marginal generator would no longer be able to supply all locations within the region. For connection points located downstream of the constraint, an additional megawatt of electricity could now only be supplied by another, more expensive, generator. This means that local prices differ from one another, and the local prices will also differ from regional prices.[67]

In the majority of cases of transmission congestion, the local prices faced by scheduled and semi-scheduled market participants are expected to be lower than the regional price. This is because transmission congestion often constrains off lower cost generators in a particular part of the network; meaning that a more expensive generator will need to be dispatched in

66 That is, residue over and above that required to pay financial transmission rights in any given dispatch interval.

67 This is necessarily true given that the regional price is to be derived from a volume-weighted average of the local prices that non-scheduled demand and supply face.

order to supply consumers located elsewhere in the region (which would lead to a higher regional price).[68]

The differences between the local prices that scheduled and semi-scheduled generators receive and the regional price that non-scheduled load pays as a result of binding transmission constraints will effectively result in **congestion residues.**

Intra-regional congestion residues do not arise (or at least are not visible) under the existing arrangements. Imagine that all generators were currently settled at their local price. Under the current arrangements, the difference between their local price and the regional price is automatically and implicitly allocated to generators in proportion to their physical dispatch, meaning that generators are only exposed to the regional price for their physical dispatch. The mechanism to allocate congestion settlement residues intra-regionally is therefore inherent in the regional pricing regime.

In contrast, inter-regional congestion settlement residues do arise. This is because different regions are settled at different prices. An excess of generation to meet load within a particular region flows across the inter-connectors to serve (at an overall lower cost) the load in a different region. The regional prices in both regions can differ as a result of both losses and congestion between the regions. Eligible registered participants are able to access a proportion of inter-regional residues through the purchase of settlement residue distribution units in the quarterly settlement residue auctions held by AEMO.[69]

5.5.2 Financial transmission rights will be backed by settlement residue

Financial transmission rights would be backed by the settlement residues that arise for the reasons described above.

The settlement residue is the natural 'counter party' to financial transmission rights, rather than TNSP or any other market participants. When there are price differences between locations (and between locations and the regional prices), this *simultaneously* creates both:

- obligations to payout under the FTRs, with the size of the payout being a function of the price differences and the active quantity of FTRs paying out, *and*
- settlement residue, with the size of the residue being a function of the price differences and the physical flows on the lines between the locations.

Providing the number of FTRs active is consistent with the physical capacity of the network in any given dispatch interval, then there will be exactly the right amount of settlement residue to fund the FTR payouts.[70]

Financial transmission rights would therefore:

68 The exception to this is where there are looped flows within a meshed network, or where a market participant holds some measure of market power behind a constraint. As discussed in Chapter 7, we have a plan to model the network in order to better understand how prices may diverge with the changes to wholesale pricing under our proposed model.

69 This process relates to regulated interconnectors only.

70 Subject to actual losses, discussed in section 5.7.

- introduce a new mechanism by which market participants would be able to manage the risks of congestion and losses[71]
- replace, and improve upon, the existing SRAs.

BOX 14: FINANCIAL TRANSMISSION RIGHTS WILL PROVIDE A BETTER RISK MANAGEMENT TOOL THAN SRA UNITS

Currently, generators that trade inter-regionally can partially hedge against inter-regional price risk.

They can do this by purchasing the right to a share of the inter-regional settlements residue (IRSR) that accrues when prices between regions separate. The value of the IRSR is equal to the difference between the price paid by retailers in an importing region and the price received by generators in an exporting region, multiplied by the amount of flow across the relevant interconnector.

Such rights are known as settlement residue distribution units (SRDU), or more commonly, settlements residue auction units.

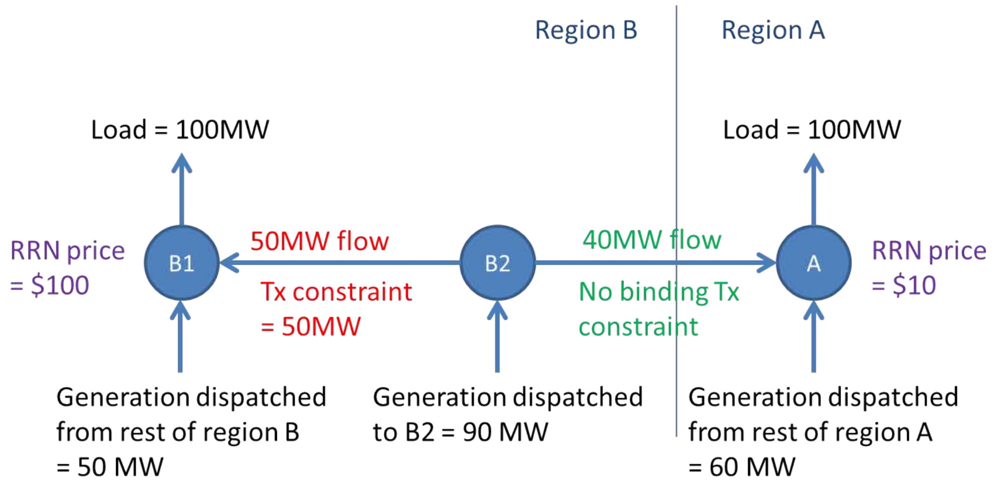
SRA units provide an effective inter-regional hedge only when the interconnector is able to flow at capacity and in the direction equal to the volume of SRA units sold. This is because of a phenomenon known as counterprice flows. Counterprice flows describe the situation where electricity flows from a lower priced region to a higher-priced region.

For example, take the example shown in Figure 5.1 below. Load on one side of a regional boundary in region A may be best served (from the perspective of dispatch efficiency) from generation on the other side of the boundary in region B. This will result in flows across the interconnector from region B to region A. This might occur even if the local price at the regional reference node in region B (i.e. the regional reference price) is higher than that in region A.

This example of counterprice flow is efficient from the perspective of dispatch.

71 Noting that these risks currently manifest through reduced physical dispatch, and changing marginal loss factors.

Figure 5.1: Counterprice flows under the current arrangements



Source: AEMC

Incentives to undertake race to the floor bidding behaviour in the presence of transmission constraints can exacerbate the instances of counterprice flows, resulting in counterprice flows which are inefficient.

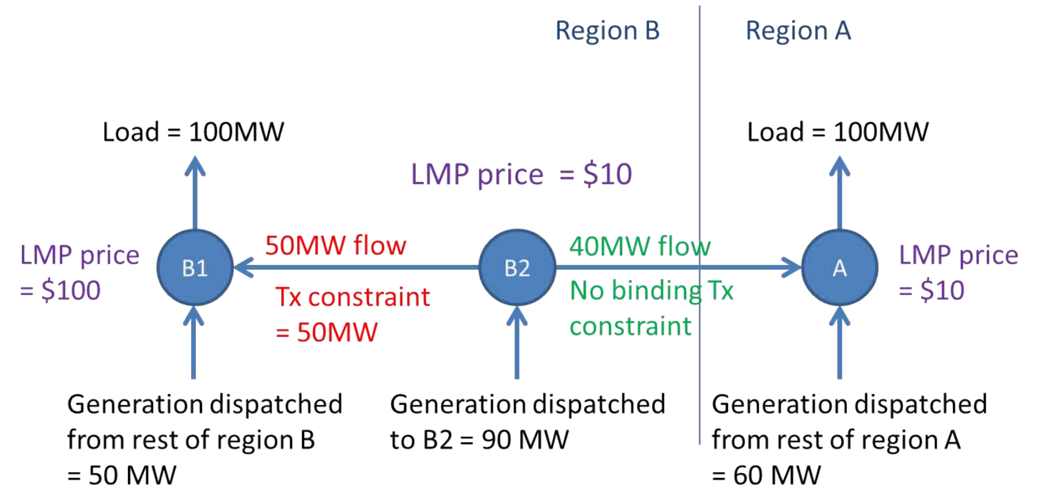
Regardless of the reasons for counterprice flows, there will be negative settlement residue (paid for by consumers via TUOS) and no payout under the SRA, despite the price difference between region A and region B.

In contrast, under our proposals:

- there can be no counter-price flows between nodes on the network. The dispatch engine will always dispatch from low to high priced nodes
- the incentive for race to the floor bidding behaviour is removed, for the reasons discussed in section 3.2.1
- the settlement residue that accumulates is exactly equal to the flows on the network, multiplied by the price difference between nodes on the network. It will always be zero or positive. And providing the number of FTRs sold is consistent with the physical capacity of the system, there will be sufficient settlement residue to back the relevant FTRs, so they will be paid in full.

The same circumstances are replicated below, but with local pricing applying to node B2.

Figure 5.2: Interconnectors flows under dynamic regional pricing



Source: AEMC

5.5.3 Making sure there is sufficient revenue to back financial transmission rights

Settlement residue is a function of the capacity of the transmission infrastructure available in any given dispatch interval. Conversely, the FTR payouts are a function of the quantity of FTRs sold well in advance of the dispatch interval.

It is therefore possible that the payouts to any particular FTR will not be exactly met by the settlement residue that arises in any given dispatch interval or for a given constraint. This will result in shortfalls or excess settlement residue on a dispatch interval by dispatch interval basis.

This raises the following questions:[72]

- what should happen to any excess settlement revenue not required to back a FTR in a given dispatch interval or for a given constraint?
- how should shortfalls in settlement revenue be managed in a given dispatch interval or for a given constraint?

The Commission favours the following approach to make sure there is sufficient revenue to back the FTRs:

- The quantity of FTRs made available should be determined such that we are commonly dealing with *excess* revenue, and only rarely dealing with a settlement *shortfall.*
- Excess settlement residue at a given time and at a given point in the network should be used to offset shortfalls in settlement residue at later times and in other parts of the

72 These questions do not arise in the status quo arrangements because the settlement residue that arises between local prices as calculated by the dispatch engine but discarded for the purpose of settlement, and regional prices, is automatically and implicitly allocated to generators in proportion to their physical dispatch.

network. In effect, there would be an excess settlement residue fund to be managed by AEMO, which would increase and decrease over time, but could never go negative.

- To the extent the above approaches result in insufficient revenue, the FTR quantity should be scaled back.

Consequently, the financial transmission rights are not fully firm: market participants which hold financial transmission rights are exposed to the residue risk of insufficient revenue. As noted in Chapter 7, the Commission plans to conduct some modelling next year in order to ensure that the products being designed are sufficiently firm and effective for risk management purposes.

Additionally, the Commission considers that revenue generated through the sale of FTRs should be used to offset TUOS and so should *not* be used as an additional source of revenue to offset shortfalls.

The Commission also envisages that the existing market impact component of the STPIS TNSP incentive scheme would be enhanced and would be used to provide more precise financial incentives to TNSPs to operate their network in a manner which maximises network capacity when it is needed. This approach would be expected to increase the firmness of financial transmission rights by making sure that TNSPs have an incentive for network capacity to be made available when it is valued.

Further explanation and rationale for the Commission's preferred approach is as follows.

5.5.4 Determining the quantity of financial transmission rights sold

Determining the quantity of financial transmission rights to be sold is discussed in section 6.2, and is done with regard to the expected physical capacity of the system.

In doing so, the Commission favours that the quantity of FTRs are determined, so that it is very often the case that there is excess settlement residue.[73] This will tend to reduce the prospect of needing to reduce the firmness of the FTRs through scaling and should improve the ability of market participants to manage their risk.

This approach also reflects the likelihood that when excess revenue arises it will typically be relatively small, but when shortfalls arise they may be relatively large. This is due to, for example, a network outage substantially reducing physical capacity and leading to high regional prices.

Clearly, however, there is a balance to be struck. The more conservatively the quantity of FTRs is determined, the fewer the FTRs that are available to generators to manage their risk: that is, more generators will be exposed to the local price for more of their capacity. Over time, as confidence in the process for determining the appropriate number of FTRs increases, it may be possible to increase the number FTRs sold.

73 Rather than insufficient settlement residue to back the FTRs

5.5.5 Treatment of excess settlement residue

Excess settlement residue could be use offset shortfalls in settlement residue in other parts of the network, and/or at other times, or simply returned to consumers. This can be simplistically represented in the matrix below:

Table 5.2: Treatment of excess settlement residue

	NOT OFFSET IN ANOTHER DISPATCH INTERVAL	OFFSET IN ANOTHER DISPATCH INTERVAL
Not offset in another area of the network	Not offset by time or by location. All excess settlement residue returned to consumers.	Excess settlement residue for a particular part of the network would accumulate over time and be used to offset shortfalls in settlement residue in the same part of the network at a later date. Excess settlement residue from one part of the network would not be used to offset settlement residue in another part of the network.
Offset in another area of the network	Excess settlement residue across the network would offset shortfalls in other parts of the network. However, excess settlement residue above and beyond that required in any given dispatch interval would be returned to consumers.	Offset by both time and location. Settlement residue would accumulate in a fund.

The Commission's preference is that excess settlement residue that accumulates in a particular dispatch interval would be used to offset a shortfall in settlement residue in a different dispatch interval (i.e. the bottom-right hand box in the table above). This should occur across all constraints and time periods. That is, there would be a single fund, administered by AEMO, which would rise and fall as settlement residues were greater or less than that required to pay FTRs.

The fund could never go negative (with shortfalls *to the fund* being met through scaling financial transmission rights, as described below).

The Commission proposes that the fund would be indefinite, in size and time. The alternatives would be to:

- cap the fund at a certain dollar amount (beyond which and excess settlement residue would be returned to consumers); or
- to redistribute the proceeds of the fund on a regular basis.

The Commission's preferred approach is simple. It also makes the FTRs firmer or allows more FTRs to be sold for a given level of firmness, because *all* excess settlement residue can be used to offset settlement residue shortfalls. In turn, this should be in the interest of consumers as it should reduce market participants' cost of capital, and increase the revenue generated through the sale of the FTRs.

Although determining the quantity of the FTRs sold would be modelled with regard to each individual element of the network and over time, we would not have to be concerned by revenue adequacy for each individual element of the network in each discrete time period. Over- or under-estimations of the capability of the network for the purpose of determining the quantity FTRs would, effectively, offset one another (although not necessarily perfectly).

Of course, a single fund creates a degree of 'smearing' across both time and geography. Shortfalls in one part of the network would in effect be subsidised by excess revenue in other parts, and shortfalls at one time would be subsidised by excess revenue at other times. While this is a downside, the Commission, on balance, favours its approach for the reasons provided above.

Furthermore, FTRs that precisely match the physical capacity of the system on a dispatch interval by dispatch interval basis are less important given our preferred approach to transmission planning. This is because the sale of FTRs is not directly influencing investment in the physical capacity of the network, and so the impact of smearing on the FTR buying behaviour of market participants does not directly flow through to different transmission investment decisions.

The Commission does not prefer the alternatives of not using excess settlement residue to offset shortfalls (i.e. the other three boxes in the matrix above).[74] In each case, this would reduce the firmness of the FTRs, as it would quarantine (either by time or geography, or both) the funds that could be used to offset shortfalls.

Furthermore, quarantining funds by geography, network constraint or network element would require multiple funds. Defining these funds is likely to be challenging. For example, should the funds be by constraint, or part of the network, and if so, how would that part of the network be defined?

The Commission welcomes views from stakeholders on this discussion.

5.5.6 Scaling of FTR payouts

As discussed above, the financial transmission right fund would not be able to be negative. If the fund is exhausted, then payments from the FTRs will be scaled back to the extent necessary to ensure that the settlement residue that arises within a dispatch period is exactly sufficient to pay the (scaled) FTR payment.

74 Either in the particular dispatch interval in question, or across the network, and instead returning it directly to consumers.

The Commission has not considered how the scaling would happen in detail, but it favours a simple approach where each FTR is scaled by the same amount or proportion (with that amount or proportion being determined to precisely maintain the fund at zero).

This means that the FTRs would not be fully firm, and FTR holders retain the residual risk of settlement shortfall. The Commission finds this preferable to either TNSPs taking the risk (which would radically alter their risk profile), or consumers funding the shortfall through TUOS.

5.5.7 Auction revenue

The Commission has also considered whether it is appropriate to further firm the FTRs by using the revenue used from the sale of the FTRs as another source of money prior to scaling the FTRs. This would have the benefit of making the FTRs firmer, although it would reduce the amount of revenue generated from the sale of the FTRs used to offset TUOS charge.

The Commission does not favour this approach. Consumers, who fund the transmission network out of TUOS, should be reimbursed by market participants that wish to access the settlement revenue that arises as a consequence of that transmission network.

QUESTION 10: REVENUE TO BACK FTRS

1. How the number of FTRs sold should be determined? How, specifically, might this be achieved/targeted?
2. How should excess settlement revenue not required to fund financial transmission rights be treated?
3. Who should pay for any shortfall in settlement revenue?
4. Should the revenue from the sale of the financial transmission rights be used to back the FTRs?

5.6 What risks do financial transmission rights manage?

BOX 15: RISKS THAT THE INSTRUMENTS HEDGE AGAINST

The financial transmission rights would hedge the full price difference between nodes, including those price difference arising from non-thermal constraints.

As discussed in chapter 4, dynamic regional pricing will take into account the impact of all thermal and non-thermal transmission constraints that are included in NEMDE.[75]

75 Transmission constraints include thermal and stability constraints, such as transient, voltage, oscillatory and system strength stability constraints.

Given that market participants will be exposed to local prices which take into account all transmission constraints, ithe FTR products available to market participants will also hedge these risks.

However, complexities and difficulties arise in the development of financial transmission rights for non-thermal constraints.

As discussed in section 6.2, the quantity of FTRs sold is determined with regard to the physical capacity of the transmission system, which in turn determines the quantity of settlement residue that arises to back the financial transmission right payments. Therefore, the "right" number of FTRs need to sold - otherwise:

- some market participants will (in hindsight) have been unnecessarily exposed to their local price without a financial transmission right, despite the fact that the physical capacity of the network could have backed more FTR sales, or
- selling too many FTRs means there is insufficient revenue to back the FTRs, and the payment under the FTRs are scaled back accordingly.

The Commission has recommended a number of design features to mitigate these risks, some of which are discussed in the subsequent chapter on the procurement process.[76]

These risks may be more acute for non-thermal constraints.

For example, system strength constraints are, in part, a function of the type of generation that is generating or not generating in parts of the network at any given time. This means that constraint may bind in a manner which is difficult to predict several years in advance. While this does not present a challenge for the settlement algebra, it does mean that the firmness of the FTR could be unpredictable. As discussed in Chapter 7, the Commission intends to undertake a more detailed study of this issue, and its possible impact on FTR firmness.

Having an effective system security framework is a priority of the Commission. With regard to the proposed model, it will help to make the system security related constraints in the dispatch engine more certain and predictable, as well as making sure there is sufficient network capacity in place to help facilitate the provision of security services. The Commission is carefully considering the interaction of COGATI with its work to improve system strength frameworks.

QUESTION 11: NON-THERMAL CONSTRAINTS

1. Has the Commission identified the challenges relating to non-thermal constraints? How might these challenges be accommodated in the design of the FTRs?

76 Only selling FTRs three years into the future so that we have greater confidence in our estimates of the physical capacity of the transmission system; only selling FTRs relating to a proportion of the expected capacity of the system in the future and continually reassessing how much should be released in subsequent tranches; using any excess settlement revenue that accumulates over time and across the network to offset shortfalls, to smooth the risk of overs and unders in settlement revenue.

5.7 How are losses hedged?

> BOX 16: LOSS FTR INSTRUMENTS
>
> Financial transmission rights should hedge the risk of price differences arising from losses, backed from settlement residue arising as a consequence of losses. Specific details of how this would occur is yet to be determined.

The sections above have focused on financial transmission rights which hedge against price differences that arise due to **congestion** on the transmission network. Differences between local and regional prices also arise because of **losses**.

The Commission's preference is to design financial transmission right instruments that allow market participants to hedge the risk of price differences across the network that arise from losses.

Given various differences between losses and congestion (discussed below), the Commission considers it is preferable to introduce the ability for losses and congestion to be hedged within a single financial transmission right. This would hedge the full price difference arising between nodes. While there could be separate products (for losses on the one hand and congestion on the other), the Commission considers it would be easier for them to be part of the same instrument, both from a settlement algebra point of view and for market participants. We welcome views on whether it would be helpful for them to be the same, or separate, instruments.

The Commission is continuing to design the FTR instruments as they pertain to losses (and considering whether it should be separate from the congestion instrument), noting a number of specific challenges that arise for losses.

5.7.1 Losses settlement residue

Loss residues already arise from the wholesale market settlement process. This is because marginal loss factors (MLFs) are currently used to adjust prices between the regional reference node and the transmission connection point of a customer.

The existing MLF process tends to recover more from customers than what is required to pay generators for the electricity generated. In addition, some metering inaccuracies arise in the measurement of electrical flows. The difference arising results in intra-regional loss residues.

Under the specification for dynamic regional pricing, losses would no longer be oriented towards the regional reference node. They would also be dynamically calculated, rather than static in nature.[77] However, intra-regional loss residues would still exist.

77 See Chapter 4 for a discussion.

Intra-regional loss residues are currently paid to the transmission network service provider for the associated region and are used to reduce TUOS charges that are ultimately paid by electricity consumers. Inter-regional loss residue is currently allocated to the holders of SRA units.

Under the Commission's proposal this would no longer be the case. Instead, and as with congestion, the settlement residue that arises from losses would be used to back FTRs that are sold to market participants. The revenue from the sale of FTRs, including for losses, would be used to offset TUOS instead.

5.7.2 Design of transmission losses FTRs

As with price differences that arise from congestion, it is preferable from a risk management perspective for market participants to be able to hedge price differences that arise across the network due to losses.

In order to provide market participants the ability to better manage the risk arising from losses, the Commission is proposing introducing losses into FTRs. This can be considered analogous to the financial transmission right instrument described throughout the rest of this chapter for congestion; however, differences are highlighted below.

As with the design of locational marginal pricing and financial transmission rights for congestion, the Commission's intent for the treatment of losses is that:

- market participants would continue to be exposed, on the margin, to prices which include marginal losses, in order to provide market participants with the appropriate incentives in operational and investment time scales
- market participants would be able to enter into FTRs which allow them to effectively manage the risk of changing marginal losses.

However, the design of FTR instruments which incorporate losses present a number of challenges, including that:

1. transmission losses reflect that some electricity, and hence some residue, will be lost from the supply source to the customer, meaning that settlement residue is insufficient to fund FTR payouts
2. losses are based on electricity *flows*, not transmission *capacity*
3. a continuous or time of use FTR may be a poor instrument for hedging losses risk

The Commission is still considering in the design of FTRs which incorporate losses in light of these issues.

> **QUESTION 12: LOSSES**
>
> 1. Has the Commission identified the challenges relating to losses? How might these challenges be accommodated in the design of the FTRs?

6 PROCUREMENT OF FINANCIAL TRANSMISSION RIGHTS

6.1 Summary of key design features

The following table provides the proposed specification for the procurement of financial transmission rights for stakeholder feedback.

Table 6.1: Summary of key design features for the procurement of financial transmission rights

ISSUE	PROPOSED DESIGN CHOICE
Method of sale for financial transmission rights	Financial transmission rights would be sold through a series of simultaneous feasibility auctions of the network run by AEMO, with input from TNSPs being used to set the parameters of how many financial transmission rights could be sold. The auction would determine the quantity and combination of financial transmission rights sold, given market participants willingness to pay for them and the expected physical characteristics of the network. The simultaneous feasibility auction is designed to provide financial transmission rights with an appropriate level of firmness.
Tenure of financial transmission rights and lead time	Quarterly products would be available up to three to four years in advance. For example, participants could purchase a right for the immediately upcoming three-month period, or for a three-month period three or four years in the future.
Participants in the auction	Only physical market participants should be able to purchase financial transmission rights in the auction run by AEMO with the payout on the difference between local prices and regional prices. In addition, their ability to purchase these financial transmission rights through the auction run by AEMO should be capped at some measure of their physical capacity in the market. In contrast, all market participants (including non-physical participants) would only be able to purchase financial transmission rights that payout on the difference between two regional prices. Anybody would be able to participate in any secondary market for FTRs which emerges.
Transparency of procurement process	AEMO should maintain a register of the amount of financial transmission rights sold at auction and the clearing price. The register would also include information about the current holders of financial transmission rights, including where changes in ownership occur due to secondary trades.

The following sections discuss these elements of the design specification in greater detail.

6.2 Method of sale for financial transmission rights

BOX 17: METHOD OF SALE

Financial transmission rights would be sold through a series of auctions run by AEMO.

The auction would determine the quantity and combination of financial transmission rights sold, given market participants willingness to pay for them and the expected physical characteristics of the network, in order to provide financial transmission rights with an appropriate level of firmness.

We are proposing that financial transmission rights would be sold through a series of auctions run by AEMO. TNSPs would have to provide input to AEMO on the physical characteristics of their network.

6.2.1 What quantity of financial transmission rights is sold?

The auction would be based on a detailed network model (called a 'simultaneous feasibility study') that calculates the amount of financial transmission rights that can be sold, based on:

- the investment decisions made by TNSPs with regard to existing and committed network capacity[78]
- the existing financial transmission rights that have already been sold to other market participants.

The intent of this process would be to maximise the value of the financial transmission rights sold while promoting sufficient settlement residue to back the financial transmission rights sold (called 'revenue adequacy').

An auction of this nature would necessarily be complex since the power system is complex. However, it is commonly applied in overseas jurisdictions which have FTRs (including New Zealand and in multiple markets in the US). The Commission will seek to gain learnings from these jurisdictions as it progresses the auction design.

Given the meshed nature of the network, the quantity of one particular FTR having sold would impact on the quantity of FTRs available to be sold on other transmission lines.

The trade off between financial transmission rights is unlikely to be one-to-one: it may be that selling eight more of one type of financial transmission right means that ten less of another type can be sold. To manage this, the auction algorithm would seek to maximise the *revenue* generated through the auction (as opposed to the quantity). This would mean that the FTRs are allocated in the combination which is most valued (collectively) by market

78 This capacity is driven by both physical transmission infrastructure as well as any non-network options that are being utilised.

participants, and so would best allow them (collectively) to manage transmission congestion and loss risk.

It is important that a simultaneous feasibility method is employed, rather than a sequential auction approach. A sequential auction approach is where the quantity of a particular product is determined first, and then the quantity of another product determined next. Such an approach would not take into account the trade-offs between products, and would be unlikely to result in an efficient allocation of financial transmission rights.

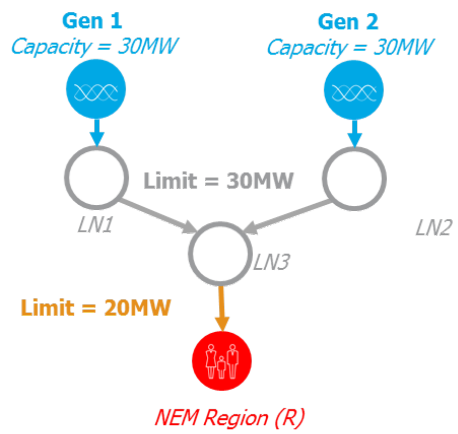
BOX 18: SIMULTANEOUS FEASIBILITY STUDY ON A SIMPLIFIED NETWORK

Below sets out a simplified example for how a simultaneous feasibility study could occur.

In this example, each of the links connecting the generators to LN3 are 30MW, but the limit between LN3 and the new region is 20MW. Therefore, the maximum available volume of FTRs that would be available for the generators to purchase to manage any differences in price that may arise between the generators' local prices and the regional price will be limited by the LN3-R path (20MW). A quantity of FTRs higher than this cannot be sold, since otherwise there would be insufficient settlement residue available to pay out under the rights. The rights are financial, but the residue accrues based on the physical capacity that exists in the network.

Both generators have greater capacity than the amount of FTRs available in this example, and so Gen 1 and Gen 2 would compete in the auction for this FTR capacity.

Figure 6.1: Simultaneous feasibility study on a simplified network



Source: AEMC

6.2.2 Is there a reserve price?

The price of the financial transmission right would be determined through the auction. There would be a reserve price of zero for every financial transmission right.

This is appropriate since it would maximise the chance that generators would be able to purchase financial transmission rights, in order to give them the best ability to manage the risk of transmission congestion. This would likely mean that most of the financial transmission rights offered to the market would be purchased.

Negative bids would not be allowed (i.e. market participants would not be able to bid to be paid to acquire financial transmission rights). This is because the financial transmission rights are options, and so only result in positive pay outs.

6.2.3 What is the governance of the auction?

We consider that AEMO is the most appropriate party to run the auction. This is for a number of reasons:

- The operation of the auction is a by-product of the existing operation of the market by AEMO. Settlement residues arising from the difference between locational marginal prices and the regional reference price are collected by AEMO. AEMO has direct access to these residues. At the same time, AEMO is the only party with a model of the entire network, required to determine the combination of possible financial transmission rights that should be sold.
- It is important that the auction process is as transparent to market participants as possible. The Commission considers that AEMO, as market operator, is the party best placed to ensure transparency in relation to all aspects of the auction including its interaction with other closely linked market processes.

However, TNSPs will still have an important role to play. TNSPs will need to provide AEMO with detailed information about the characteristics and design of their network. This could be similar to the current development of constraints in the NEM dispatch engine. TNSPs currently generate limit equations, with AEMO converting these into the constraint equations. A similar process could occur here.

TNSPs would also be subject to an incentive scheme, which is discussed in box 15 below.

BOX 19: EXISTING TNSP INCENTIVE SCHEME WILL BE ENHANCED

The market impact component of the current Service Target Performance Incentive Scheme (STPIS) will be enhanced. The granular information from dynamic regional pricing will be used to inform the market impact component, rather than having the incentive based on all relevant outage events with a market impact of over $10/MWh.

Therefore, TNSPs will receive a small financial reward as an incentive to manage the physical capacity of the system. Symmetrically, TNSPs can also be penalised. Penalties and rewards under the scheme will flow to and from TUOS.

The operating incentive scheme would enhance the existing market impact component of the STPIS. As such, the Commission expects that the 'strength' (i.e. the revenue at risk) of the incentive scheme would be the same. This is to avoid significantly altering the TNSPs' risk profile.

There would also need to be a consideration of what network conditions would be used to set the parameters of the transmission capacity under the auction. This would set the amount of financial transmission rights that would be sold.[79] It is important to set these parameters well, so that market participants have some assurance that the financial transmission rights are sufficiently firm.

TNSPs would therefore need to provide AEMO with information about what the constraints would be under the conditions used in the auction. There would need to be a common set of principles governing this across the different TNSPs. For example, the conditions considered should be:

- nationally consistent
- coincide with instances where potential constraints would either occur frequently or lead to high divergence in prices
- take into account market factors that could materially influence transmission capacity (e.g. local loads)
- take into account ambient environmental factors that could materially affect transmission capacity (e.g. temperature).

As discussed in section 5.5, the quantity of financial transmission rights to be sold would be calculated to improve the firmness of the financial transmission rights.[80] Since it is impossible to fully guarantee the firmness of the financial transmission rights given the possibility, however remote, of severe transmission network outages or new constraints emerging, it is preferable for the auction to release a level of financial transmission rights that could reliably be paid out through settlement residues. The risks increase significantly if too many financial transmission rights are released.

6.2.4 How would the auction be designed?

Many details of the auction design are still to be worked though, and trade-offs may need to be made along the way. Details that are yet to be determined include (but are not limited to):

- whether the price paid is a clearing price or a pay as bid price
- whether 'linked bids' are feasible. Ideally, a market participant would want to be able to specify that it only wants to purchase financial transmission right A if it also purchases financial transmission right B. Such linking could be:
  - by location (e.g. I only want A to B if I also have B to C)
  - by time (e.g. I only want A to B this season if I also have A to B next season)
  - by product type (e.g. I only want time of use product A if I also secure time of use product B).

79 That is, given a specified set of conditions, the payout under any financial transmission rights purchased would be exactly met by the settlement residue that arises.

80 Balancing the need to sell an adequate number of financial transmission rights to allow generators to manage their risk.

- how the auction could permit market participants to sell financial transmission rights into the auction, at a reserve price set by the seller - we want the seller to be able to release its financial transmission rights if it no longer considers these valuable.

> QUESTION 13: METHOD OF SALE
>
> 1. Do you agree with the proposal to use a simultaneous feasibility auction to determine the quantity and combination of financial transmission rights to be sold?
> 2. Should AEMO be responsible for this auction?
> 3. Should the reserve price be zero?
> 4. What other insights do you have on the design of the auction?

6.3 What is the tenure and lead time of financial transmission rights?

> BOX 20: TENURE AND LEAD TIME
>
> Quarterly products would be available up to three to four years in advance.

Financial transmission right tenure refers to the length of time that the FTR applies to. FTR lead time refers to the time in advance that the rights can be purchased.

The Commission's indicative preference is that financial transmission rights of a tenure of three months can be purchased up to three to four years in advance. For example, if the lead time was three years, FTRs for a particular three-month time period would therefore be released in 12 (roughly) equal tranches:

- In the first tranche, one twelfth of the estimated number of financial transmission rights that are able to be backed by the physical system (as determined through the process described above) would be released for auction three years ahead of the start date of the financial transmission right
- In the second tranche, one *eleventh* of the *remaining* estimated number of the financial transmission rights that are able to be backed would be released *two years and nine months* ahead of the start date
- In the third tranche, one tenth of the remaining financial transmission rights would be released two years and six months ahead of the start date
- And so on, such that in the penultimate tranche, half of the estimated remaining number of financial transmission rights would be released three months before the start date, and in the last tranche, all of the estimated remaining number of financial transmission rights would be released (and would be effective almost immediately).

A similar approach is currently used in the settlement residue auction.[81]

81 This auction under rule 3.18 of the NER is for settlement residue distribution units relating to directional interconnectors.

The Commission favours this approach because:

- three month tenures (rather than shorter) reduce administrative costs and complexity, and is consistent with the typically traded wholesale market hedges and the existing SRA units. Shorter financial transmission rights could be sold on the secondary market if required.
- financial transmission rights for longer than three months (up to three to four years) could be acquired through the auction through linked bids (providing such an approach is accommodated in the auction design)
- releasing the financial transmission rights in tranches:
    - limits the prospect of any particular market participant acquiring a large proportion of the financial transmission rights, and then having market power (either in the secondary market for FTRs or the energy market)
    - allows for new market participants to acquire financial transmission rights. Otherwise, there could be a barrier for entry created, whereby generators were limited in their ability to acquire financial transmission rights for an extended period of time.
    - allows for the quantity of financial transmission rights released to be fine-tuned. As we approach real time, we are more likely to be able to accurately forecast the physical realities of the transmission system, and hence the appropriate number of financial transmission rights to be released. To the extent that the system is *less* capable than previously envisaged, proportionately less financial transmission rights would be sold in subsequent auctions, and vice versa. This allows for the trade-off between the quantity and firmness of the financial transmission rights to be fine-tuned.
- A three-year lead time is consistent with readily traded ASX wholesale contract market products and existing SRAs. However, a four-year lead time may alternatively be appropriate if it corresponds with two biennial iterations of the ISP.

Products further into the future would be better for market participants to manage the risk of transmission congestion. However, it also:

- increases the likelihood that the transmission network capacity may be different and so there be insufficient settlement residue to back the FTR payments
- may be difficult for participants to undergo a process of price discovery so far in advance.

On balance, the Commission favours a lead time of three to four years. The possibility of longer term financial transmission rights are discussed in the accompanying discussion paper on renewable energy zones.

QUESTION 14: TENURE AND LEAD TIME

- What is the appropriate tenure for the financial transmission rights?
- How far in advance should the financial transmission rights be made available? What factors should the Commission take into consideration when determining the lead time?

6.4 Who would be allowed to participate in the auction?

BOX 21: AUCTION PARTICIPANTS

Only physical market participants should be able to purchase through the auction run by AEMO financial transmission rights that hedge the price difference between a local price and a regional price. In addition, their ability to use these financial transmission rights should be capped at some measure of their physical capacity in the market.

In contrast, all market participants (including non-physical participants), would only be able to purchase through the auction financial transmission rights between regional prices.

Anybody would be able to trade FTRs on any secondary market for FTRs that may emerge.

We consider that only physical market participants should be able to purchase financial transmission rights between a local price and a regional price through the auction process run by AEMO. In addition, their ability to purchase these financial transmission rights should be capped at some measure of their physical capacity in the market.

A potential downside of this approach is that the revenue generated through the auction could potentially be lower than it otherwise would, as demand for the financial transmission rights would have been lessened. Obviously, this depends on how many market participants are seeking to connect to the power system and in what location, and hence the level of competition for financial transmission rights.

However, we consider it is important to keep the products sold through the auction available only to physical players, at least initially. Allowing non-physical participants to buy hedges through the auction risks reducing the number available to physical participants, reducing their ability to manage risk. Capping the amount sold at the physical capacity of market participants also limits there ability to gain a large amount of FTRs which they might use to exert market power.

There are also legal challenges to letting non-physical players participate in the auction. Depending on the ultimate design of these reforms, the Commission may not have sufficient rule-making power under section 34 of the NEL to make rules about non-physical participants (i.e. persons who do not participate in the wholesale exchange for electricity or who are not otherwise involved in the operation of the national electricity system).

Determining 'physical capacity' for the purposes of capping the quantity may be challenging, particularly in the case of scheduled load. We are continuing to explore the best way to do this.

In the case of financial transmission rights between regional prices, our preferred approach is that non-physical players should be allowed to purchase financial transmission rights. However, depending on the ultimate design of these reforms, the Commission may also not have sufficient rule-making power to make such rules.

There would be no restrictions on any party participating in a secondary market for FTRs, should such a market emerge.

QUESTION 15: AUCTION PARTICIPANTS

1. Should participants to the auction be limited to physical market participants in the case of financial transmission rights between local and regional prices?
2. Should non-physical participants be allowed to buy financial transmission rights between regional prices?

6.5 What transparency would there be of financial transmission rights?

BOX 22: TRANSPARENCY IN THE FINANCIAL TRANSMISSION RIGHTS MARKET

AEMO would maintain a register of the amount of financial transmission rights sold at auction and the clearing price. The register would also include information about the current holders of financial transmission rights.

Market transparency can be defined as the availability of relevant information to market participants. Transparency is an important component of a well functioning market. In the context of a market for financial transmission rights, this information may include the:

- amount of financial transmission rights that were bought and sold in an auction
- price at which the financial transmission rights were sold
- parties that bought or sold financial transmission rights in the auction.

In addition, there is the added question of how transparent any secondary sales[82] of financial transmission rights should be.

Competitive, efficient and reliable market outcomes are more likely to be achieved when current market participants, and prospective participants, have access to information about current and forward electricity prices and the factors driving those prices, including supply and demand conditions.

In the context of a market for financial transmission rights, publishing certain market information could assist with:

1. the **price discovery process** for market participants:

   If the outcomes of previous auctions are published, then market participants may be better placed to bid into future auctions in a competitive and well-informed manner. It

82 A secondary sale is where financial transmission rights are bought and sold outside the auction held by AEMO. This sale may occur through a bilateral trade or through a secondary trading platform.

may also be expected that the competitive discipline of the auction process may be more likely to lead to a fair value over time for the financial transmission rights that are sold.

2. determining whether **market power** concerns are likely to arise:

   Transparency may assist regulators and other participants in identifying whether the potential for market power abuse exists. For example, a register that includes the identity of market participants and the corresponding amount of financial transmission rights they hold may illuminate whether there is an undue concentration of financial transmission rights to one or a few market participants in particular region or subregion.

3. providing an **educational benefit** for industry participants and the wider public:

   Publishing key market information may assist in lowering any barriers to entry that exist within the market for financial transmission rights. In addition, such information may serve a public policy benefit if it is available to the wider public, including policy-makers and academics.

However, transparency can also result in additional costs. For example, a high level of transparency may result in significant cost for the market participants that need to provide information. Therefore, the additional value of added transparency needs to be balanced against the costs to market participants.

We consider that there is a strong case to introduce transparency into the financial transmission rights market from the outset. This is because a financial transmission rights market with transparent prices and easy accessibility for new market participants should promote competition, reliability and efficiency in the wholesale and retail electricity markets.

The design specification for financial transmission rights includes a role for AEMO to maintain a register of the:

- price of financial transmission rights sold at each auction
- amount of financial transmission rights sold
- current portfolio of financial transmission rights held by market participants.

The aim is to provide complete transparency with regard to the outcomes in the primary market for financial transmission rights (i.e. the quarterly auction run by AEMO). This means that the price, quantity and purchaser of financial transmission rights would be published by the market operator. The bid and offer prices within the auction would not need to be reported.

For secondary trades, a lower reporting burden would be imposed. Namely, market participants would be required to lodge the quantity sold and the identity of the purchaser with AEMO so that the holder of financial transmission rights can be updated within the register. This should ensure that the register is up-to-date and accurate.

Further consideration is required about the reporting requirements for non-physical market participants who acquire FTRs through the secondary market.

We understand that this proposal is similar to the transparency and reporting arrangements for financial transmission rights in other jurisdictions. For example, the FTR manager in New

Zealand is required to administer a list of the financial transmission rights held by participant and period (including secondary trades).[83] It is also consistent with the Commission's recommendation and work to improve the transparency of the over the counter contract market, and to enhance the AER's powers to monitor contract market liquidity.

QUESTION 16: FINANCIAL TRANSMISSION RIGHTS TRANSPARENCY

1. What information relating to the sale of financial transmission rights should be made transparent?

83 See https://www.ea.govt.nz/dmsdocument/22503-overview-of-the-ftr-market.

7 QUANTITATIVE ANALYSIS

7.1 Objectives for quantitative analysis

The majority of stakeholders that responded to the June directions paper suggested that some form of quantitative analysis should be undertaken on the proposed model.[84]

However, stakeholders' objectives for this modelling varied. For example, objectives cited included:

- Evaluation of the benefits and the costs of the proposed model in order to assist with evaluating whether it is likely to promote the national electricity objective. Several stakeholders were of the view that this exercise should consider a number of different scenarios for the future development of the market and how the net benefits may differ for different stakeholders.
- Providing evidence to support specific design decisions within the proposed model. For example, analysis to inform the potential incidence of market power concerns, which may inform how these market power issues might be tackled.
- Providing evidence of the distributional impact of implementing the proposed model; for example, analysis to suggest the parties who are likely or less likely to benefit from the model.
- Providing all stakeholders with a more detailed explanation of how the proposed model might operate in practice; for example, through a simulation or trial in practice.

7.2 Our proposed approach to modelling

We agree that quantitative modelling has an important role to play in the COGATI review. As identified by stakeholders, modelling can help inform specific policy design choices and weigh the potential impacts of introducing the model, as well as provide a potentially valuable communication tool. When considering whether or not a particular change will facilitate the national electricity objective, modelling can potentially provide a useful input into the assessment - above and beyond any qualitative assessment that we undertake.

Throughout the course of the review and the rule change process next year[85], we therefore propose to address the entire list of objectives identified by stakeholders above. This will occur in a staged manner. Our approach is as follows:

- We propose to complete some quantitative analysis by December 2019.
- For larger tasks that require more detailed modelling, we propose to commence this modelling at the end of 2019. These exercises will aim to be completed by early to mid-2020, with the outcomes informing the detailed design and implementation of the proposed model through the rule change processes.

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84 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, directions paper submissions: Citipower, Powercor and United Energy; HRL Morrison & Co; Hydro Tasmania; ENGIE; Energy Queensland; AER; TasNetworks; TransGrid; Meridian Energy and Powershop; Mondo Energy; Delta Electricity; Clean Energy Council; AEC; ENA; Major Energy Users; Innogy; Spark Infrastructure; EUAA; ERM Power; Stanwell; Tesla; Aurizon Networks; Infigen.

85 See Chapter 1 for further discussion.

We have developed a preliminary overview of modelling tasks designed to meet the objectives identified by stakeholders. These are outlined in the table below and discussed in further detail in the following sections.

Table 7.1: **Proposal for modelling the COGATI review**

CATEGORY	NATURE OF TASK	BY DECEMBER 2019	BY MID-2020
1. Costs of reform	Implementation and ongoing costs	Research into the cost of introducing comparable models elsewhere	Survey of market participants, AEMO, AER and other interested stakeholders
2. Benefits of reform	Benefits of reforms	Research into the benefits of introducing comparable models elsewhere	
	Better risk management for generators	Initial estimate of benefits of improved risk management	Survey of generators
	Improved operating incentives for generators	Literature review of race to the floor behaviour	Forward modelling the cost of race to the floor bidding
	Improved dispatch efficiency	Initial estimate of benefits from dynamic loss factors	
	Better locational incentives to invest	Initial estimate of historic costs of congestion	
3. Policy design	Market power	Zonal study of network to ascertain how many participants are in each location to get an indicative estimate of market power potential	
	Sufficient settlement residue to back financial transmission rights		Simultaneous feasibility study of the network to estimate what possible payouts

CATEGORY	NATURE OF TASK	BY DECEMBER 2019	BY MID-2020
			may be under the financial transmission rights
	Effect of VWAP pricing	TBD	TBD
4. Distributional impacts	Initial indication of parties who are likely to benefit more or less from the proposed model		Assessment of distributional impacts, informed by analysis conducted under objectives 1 and 2
5. Communication	Building simplified model of how the proposed model may operate		Discrete paper trial, for example using 10 nodes over a limited timeframe

Before undertaking the proposed quantitative analysis, we considered that it would be useful to consult with stakeholders on our approach. We are seeking your feedback on each of the modelling tasks identified below, including:

- how each modelling task could be improved
- any additional modelling that may be required to meet the objectives; or
- whether stakeholders disagree with any of our reasoning.

7.3 Costs of implementing the proposed model

BOX 23: COSTS OF IMPLEMENTING THE PROPOSED MODEL

We plan to:

1. conduct research into the implementation costs of comparable reforms overseas (by December 2019)
2. assess the implementation and ongoing costs of the reform through a survey of relevant stakeholders (by mid-2020)

The Commission considers that the costs will include the:

- implementation costs for industry and the market bodies
- ongoing costs for participants and market bodies, including transaction costs.

We intend to address the task of quantifying the costs in two stages.

In the **first stage**, we will undertake research into the implementation costs of comparable models overseas. We consider that there is potential to learn from the experience of our international colleagues during similar changes to wholesale pricing and contracting. For example, the Commission will assess work completed by the Public Utility Commission of Texas (PUCT) in 2004 and in 2008 on a cost benefit analysis prior to and during implementation of more granular pricing signals and financial transmission rights. In doing so, we will be careful to assess the importance of any differences to the market structures and circumstances between these regimes and the NEM - including both the original design of the market prior to the reforms being implemented, and the nature of the market design post implementation.

During the first stage, we will also revisit similar costing exercises that have been completed in the NEM in relation to comparable changes. For example, during the 2015 *Optional Firm Access: Design and testing* review:

- AEMO completed a cost benefit assessment[86]
- the Commission employed EMCa to estimate the costs to TNSPs [87]
- we also employed Market Reform to complete work in relation to generator costs.[88]

While these numbers may be useful, they are no longer directly comparable. This is because our proposed model is significantly different.

In the **second stage**, we will undertake a survey of market participants and market bodies in order to better understand the implementation and ongoing costs of the proposed model. The survey of market participants will include both generators, demand response service providers, large energy users that may become scheduled, and large-scale storage providers. We consider that it is necessary to complete this analysis later in the market design process, as the proposed model will need to be well-developed in order for the outcomes of the survey to be meaningful.

> QUESTION 17: COSTS OF IMPLEMENTING THE PROPOSED MODEL
>
> Do stakeholders agree with our proposed approach to ascertain estimates of the costs of implementing the proposed model?

7.4 Benefits of implementing the proposed model

The Commission has identified a number of benefits associated with the proposed model that will feed into its assessment of whether or not the proposed changes meet the national electricity objective. The Commission notes that, in general, the costs of reform are easier to

86 https://www.aemc.gov.au/sites/default/files/content/6082a028-b869-49be-b633-626681d03c86/AEMO-Access-Settlements-Implementation-Cost-Estimates.pdf

87 https://www.aemc.gov.au/sites/default/files/content/3369f9de-4a9c-4d59-9c3e-04798c626c57/EMCa-Transaction-costs-of-OFA-for-TNSPs-in-the-NEM.PDF

88 https://www.aemc.gov.au/sites/default/files/content/a3f8d13e-b49b-4c4a-9f08-9331883f8393/Market-Reform-Transaction-costs-of-OFA-for-generators-in-the-NEM.pdf

quantify than the benefits. This is because the reform aims to change the *incentives* and *behaviours* of market participants, which is difficult to model.

However, we consider that it is possible to indicate the relative 'size of the prize' that the proposed model is aiming to capture. These modelling exercises are useful in that they are also relatively simple to understand, will help to inform specific design decisions and can help to illustrate potential distributional benefits.

The Commission has identified four distinct benefits that would benefit from additional modelling. These benefits are addressed in the sections below.

QUESTION 18: ADDITIONAL BENEFITS

Beyond the benefits identified, are there additional benefits that stakeholders think should be taken into consideration?

7.5 Better risk management for generators

BOX 24: BENEFIT OF IMPLEMENTING THE PROPOSED MODEL: BETTER RISK MANAGEMENT

We plan to:

1. conduct an initial estimate of the potential benefits from improved risk management (by December 2019)
2. survey generators to understand their risk management needs (by mid-2020).

We are proposing to enable scheduled and semi-scheduled market participants to better manage the risks of congestion and transmission losses by enabling them to purchase financial transmission rights. These financial transmission rights will hedge against the price differences that may arise under our proposed changes to wholesale electricity prices.

These arrangements should improve **investment certainty** for scheduled market participants and should **reduce their cost of capital** in the longer term. This is because an operating regime in which generators have greater certainty in the face of transmission constraints is one in which generators are likely to face lower risks to the cashflows of their existing generation assets. In particular, market participants with financial transmission rights would face less risk that other participants may undermine their business case by locating nearby and causing congestion or adverse loss effects in the local transmission system.

A lower cost of capital should mean that a greater number of generation investments proceed over time when compared to a scenario in which the model is not implemented. This may have a beneficial impact on the costs faced by consumers in the longer term.

The Commission proposes to model the potential 'size of the prize' for this category of benefit by December 2019. This will involve assessing the benefits to the industry and consumers of more efficient investment in generation as a result of improved risk management and a consequent lower cost of capital.

By mid-2020, the Commission will conduct a survey of generators and developers of generation assets in order to better understand the potential improvements to risk management as a result of introducing financial transmission rights.

> QUESTION 19: BETTER RISK MANAGEMENT
>
> What additional implications from better risk management do stakeholders think should be considered, beyond a lower cost of capital?

7.5.1 Literature review of quantitative analysis undertaken overseas

> BOX 25: LITERATURE REVIEW OF QUANTITATIVE ANALYSIS
>
> We plan to conduct research into the benefits of comparable reforms overseas (by December 2019)

We will undertake research into the estimated benefits of comparable models overseas. As with regard to costs, we think there is potential to learn from overseas markets which have undertaken similar reforms in the past. In some such markets, quantitative analysis has been undertaken estimating the benefits of the reforms.

Importantly, we will recognise the differences in circumstances between the overseas markets. For example, their size, market structure, market design before implementation, and physical network characteristics are all likely to be relevant differences compared to the NEM.

> QUESTION 20: BENEFITS OF REFORMS OVERSEAS
>
> 1. What overseas markets or studies could be relevant? What important differences should be taken into account?

7.5.2 Improved operating incentives for generators

> BOX 26: BENEFIT OF PROPOSED MODEL: IMPROVED OPERATING INCENTIVES
>
> We plan to:

1. conduct a literature review of race to the floor behaviour and bidding unavailable behaviour (by December 2019)
2. model the forecast cost of race to the floor behaviour and bidding unavailable behaviour in the future (by mid-2020)

Race to the floor bidding

When the system is congested, generators know that the regional reference price is likely to be higher than usual, and that they are not going to receive access to it unless they are dispatched. If a generator is not dispatched, it may risk losing significant revenue due to the position it has taken in the contract market, or incur significant opportunity cost if not contracted.

These conditions can give rise to 'race to the floor bidding' by generators. Race to the floor bidding results when generators know that the offers they make will, in all likelihood, not affect the settlement price they receive as a result of congestion between them and the rest of the market. Race to the floor bidding can involve a generator behind a constraint bidding at the market floor price (-$1,000) to maximise its dispatch quantity. This can result in inefficient dispatch through higher cost generation resources being dispatched instead of lower cost resources.

Exposing generators to the dynamic regional price removes the incentives to bid at the floor price when transmission constraints arise. Under these circumstances, the higher cost generator may lose further revenue if it places a bid at the floor price, as such behaviour runs the risk of depressing the local price which they receive to below their costs. Exposing generators to the local price means that generators are no longer incentivised to maximise their physical dispatch, even if the regional reference price is high.

The removal of incentives for race to the floor bidding has operational efficiency benefits for the NEM. In order to quantify these operational benefits, the Commission intends to complete by December 2019:

- a literature review of race to the floor behaviour
- a qualitative analysis of recent Queensland bidding behaviour related to instances of transmission congestion.

These exercises should help illuminate the potential for race to the floor bidding to get worse or better in the future, due to the evolving characteristics of the NEM.

To augment this analysis, the Commission will undertake updated forward modelling of the cost of race to the floor bidding by mid-2020. This modelling is likely to be similar in nature to the modelling completed by ROAM consulting for the Commission in 2013 for the transmission frameworks review.[89]

89 https://www.aemc.gov.au/sites/default/files/content/271255f4-4323-4931-934d-50566be6be5b/ROAM-Consulting-Modelling-Transmission-Frameworks-Review.PDF

Bidding 'unavailable'

Generators are currently incentivised to bid 'unavailable' in certain situations because the regional price does not reflect their marginal cost of supply. For example, a generator that is required to run for system security purposes may be able to exhibit non-competitive market conduct through bidding 'unavailable' and being directed on to generate by the market operator.

There is evidence that this phenomenon is leading to higher costs and a more unreliable power system for consumers. For example, our recent *Interventions into system strength* review found that during the recent system strength interventions in South Australia, wholesale spot prices were typically much lower than the directed payments that AEMO made.[90] This is because these interventions tend to occur during periods of high wind output and low demand in South Australia.

Exposing generators to the dynamic regional price removes the incentive to for generators to bid 'unavailable' when the regional reference price is lower than their cost of supply. This is because they will be able to access a higher local price if their electricity generation is needed.

The Commission plans to consider how to quantify the improvements to this phenomenon by December 2019.

> QUESTION 21: IMPROVED OPERATING INCENTIVES
>
> What literature in relation to race to the floor behaviour and bidding unavailable behaviour do stakeholders think should be taken into account?

7.5.3 Improved dispatch efficiency

> BOX 27: BENEFIT OF PROPOSED MODEL: IMPROVED DISPATCH EFFICIENCY
>
> We plan to estimate the potential benefits to dispatch if loss factors were more accurate (by December 2019)

The design specification for dynamic regional pricing proposes that intra-regional and inter-regional losses would be dynamically calculated in dispatch.

Actual marginal losses vary dynamically, depending on flows on the transmission network. Therefore, there will naturally be some dispatch inefficiency arising from differences between actual marginal loss factors and the assumed (static) marginal loss factor. Intuitively, if we assume that the static loss factors represent an unbiased estimate of average marginal loss

90 AEMC, *Investigation into intervention mechanisms in the NEM*, Final report, 15 August 2019, p. 40.

factors, the degree of inefficiency is likely to be proportionate to how much actual marginal loss factors vary from the average on a thirty-minute by thirty-minute basis.[91]

The Commission notes that there are several trends that may be contributing to increasing variance in actual loss factors, related to the de-carbonisation of the grid and associated increase in variable renewable generator resources. For example, the volatility in the output of variable renewable generators could be expected to increase the volatility in actual marginal loss factors.

The benefits that would accrue from adopting dynamic loss factors would depend on the degree of inaccuracy in the way losses are currently represented. For example, if the static marginal loss factor is very different from the actual marginal loss factor in any given dispatch interval, this could lead to generators with higher loss-adjusted costs being dispatched ahead of lower cost generators. If intra-regional losses were modelled dynamically in dispatch, the productive efficiency of the dispatch engine could potentially be improved.

By December 2019, we plan to undertake an initial quantitative assessment of the potential magnitude of the efficiency gains from introducing dynamic loss factors.

> QUESTION 22: IMPROVED DISPATCH EFFICIENCY
>
> Is the proposed methodology in relation to the efficiency gains from adopting dynamic loss factors likely to capture all the benefits from such a change?

7.5.4 Better locational incentives to invest

> BOX 28: BENEFIT OF PROPOSED MODEL: BETTER LOCATIONAL INCENTIVES TO INVEST
>
> We plan to conduct an initial estimate of the historic costs of congestion (by December 2019).

An assessment of the historic cost of congestion in the NEM can provide an indication of the potential benefit of enhanced locational signals to invest. This is because better locational signals should lead to reduced congestion in the future, as a result of improved generator siting decisions.

By December 2019, the Commission proposes to complete an initial estimate of the historic cost of congestion in the NEM. Scenario modelling can analyse the patterns and materiality of congestion, both at an intra-regional and inter-regional level. It may help to answer important questions such as:

- what has the impact of congestion been on dispatch costs

91 Soon to be a five-minute by five-minute basis, with the implementation of five minute settlement in 2021.

- how has congestion impacted on wholesale market prices
- what has the impact been on consumers
- the patterns of congestion across the NEM, and their possible impact.

> QUESTION 23: BETTER LOCATIONAL INCENTIVES TO INVEST
>
> Do stakeholders agree with the methodology described in relation to using the estimated historic cost of congestion as a basis for an estimate of the 'size of the prize' of better locational signals for investment that would be provided under the proposed model?

7.6 Policy design

Modelling of the impact of the proposed model will be addressed in order to inform three key areas of policy design.

> QUESTION 24: ADDITIONAL POLICY DESIGN AREAS
>
> Are there areas of policy design in addition to the three identified that stakeholders consider should be included in the quantitative modelling exercise?

7.6.1 Market power

> BOX 29: POLICY DESIGN: MARKET POWER
>
> We plan to undertake a zonal study of the network (by December 2019).

The introduction of dynamic regional pricing could potentially give rise to new circumstances where participants are able to manipulate the wholesale market prices above their long-run willingness to buy or sell electricity. This is because allowing prices to vary across the network effectively creates smaller ‘sub-markets’ when transmission constraints bind, and the degree of concentration in these sub-markets may mean that competition does not provide an effective constraint on bidding behaviour.

By December 2019, the Commission will undertake a study of the network to determine the share held by any one generator in each zone, and any potential market power issues that might arise as a result.

> QUESTION 25: MARKET POWER
>
> What issues should be taken into account in the proposed modelling of the impact of dynamic

regional pricing on market power?

7.6.2 Revenue adequacy of financial transmission rights

BOX 30: POLICY DESIGN: REVENUE ADEQUACY OF FINANCIAL TRANSMISSION RIGHTS

We plan to conduct a simultaneous feasibility study (by mid-2020) to assess the adequacy of revenue that would be used to back financial transmission rights.

The adequacy of the revenue required to back financial transmission rights will help to determine the volume of financial transmission rights to be sold under the proposed model at each location in the network. An assessment of revenue adequacy will also help to determine the different financial resources that could be utilised to back financial transmission rights and which of these resources are most suitable.

By mid-2020 the Commission proposes to undertake a feasibility study of simultaneous financial transmission rights demand across key shared transmission assets in the NEM. This will help to determine, or be indicative of, the combinations of financial transmission rights that can be offered across the network.

QUESTION 26: REVENUE ADEQUACY OF FINANCIAL TRANSMISSION RIGHTS

What factors do stakeholders think should be taken into consideration in modelling the demand for financial transmission rights at each point in the network?

7.6.3 The effect of VWAP pricing

The proposed model would see non-scheduled generation and load face a new regional price for electricity, called the volume weighted average price (VWAP). A key advantage of VWAP is that it would more accurately reflect underlying local prices than the existing regional reference price, which captures the local price at only one node in a region. This means that VWAP would perform better in terms of revenue adequacy than the existing regional pricing method.

Modelling the impact of moving to VWAP pricing would involve the use of a full nodal model. The Commission does not plan to conduct full nodal modelling at the current time.

QUESTION 27: THE EFFECT OF VWAP PRICING

What impacts do stakeholders see from the introduction of volume weighted average pricing in place of the existing regional reference price? What considerations do stakeholders think should be taken into account in modelling the effect of volume weighted average pricing?

7.7 Distributional impacts

BOX 31: DISTRIBUTIONAL IMPACTS

We plan to assess the distributional impacts of the proposed model (by mid-2020).

The Commission will undertake an initial assessment of the segments or participants in the market that are expected to be better off as a result of introducing the proposed model and those that are expected to be worse off. This will, as much as possible, be quantified in financial terms but may require assessment on a qualitative basis in some instances.

By mid-2020, the Commission will provide an assessment of the broad categories of the market that are expected to benefit from the model, and the categories that are expected to be worse off. Where feasible, the quantitative analysis conducted by the Commission by December 2019 in relation to the costs and benefits, will be interpreted in the context of distributional impacts.

QUESTION 28: DISTRIBUTIONAL IMPACTS

What issues should be taken into account in the proposed modelling of distributional impacts?

7.8 Communication

BOX 32: COMMUNICATION

We plan to conduct a discrete paper trial of the proposed model, for example using 10 nodes over a limited timeframe (by mid-2020).

We understand the importance of allowing market participants to understand how the proposed model may work in practice. To assist with this, we consider that it would be useful to construct examples of how the model might operate in particular circumstances on the network.

By mid-2020, the Commission proposes to conduct a small desktop or paper trial of the model using, for example, ten nodes, over a particular timeframe. A basic simulated network would be constructed, providing simulated local prices and financial transmission rights. Participants could 'purchase' financial transmission rights in a paper trial and see how this might influence payouts. This may help with education about the reform, including illustrating the degree of firmness of financial transmission rights under different scenarios.

The trial may also help to demonstrate how the proposed model will interact with related reforms, including demand response, the retailer reliability obligation and five minute settlement.

> QUESTION 29: COMMUNICATION
>
> What particular aspects of the operation of the model would stakeholders like to see in operation in a paper trial?

7.9 Why we are undertaking multiple modelling exercises

As noted in section 7.1, some stakeholders were in favour of pursuing one cost-benefit exercise.

We consider that there are three modelling techniques that could be used to provide a cost-benefit assessment. These are:

- agent based market modelling
- central planner modelling
- computational general equilibrium modelling.

Each of these approaches has merits for particular applications, and has been used to assess the costs and benefits of other reforms. However, we consider that the proposed model presents particular challenges for the application of each of these approaches.

For the reasons outlined below, the Commission does not consider that any of the three approaches will either robustly or comprehensively quantify the net benefits of the model. As such, we do not recommend pursuing them further. We consider it would be more fruitful to undertake a variety of modelling methods to elicit a number of inputs into an assessment as to whether the proposed reform would promote the long-term interests of consumers.

The Commission invites responses from stakeholders on these issues, including specific suggestions on how to overcome the difficulties with undertaking a comprehensive cost-benefit analysis.

7.9.1 Agent based market modelling

Agent based modelling creates a model of a particular market based on the individual actions of profit-maximising agents.

This is helpful in modelling the proposed model in the context of the NEM where individual market participants do not always have incentives to act in a manner that is consistent with an economically efficient outcome for the market as a whole. An agent based model could assess system costs under the existing region-wide pricing regime, and again under a locational marginal pricing regime. The difference between the two cases would provide a representation of a substantial component of the benefits of the model.

An agent based model would also be well suited to inform specific details of the model and distributional impacts, two of the key objectives of the quantitative analysis.

However, internal assessment by the Commission and consultation with a number of economic consulting firms indicates that such a model would be computationally challenging as a result of the need to model the bidding behaviour of individual agents in every five minute settlement period over several years.

It has been indicated that such an approach would be extremely time-consuming. Furthermore, the requirement to make assumptions about the bidding strategies of generators - a highly uncertain but critical requirement in the modelling - does not give the Commission sufficient confidence that the effort and time involved would be justified by the validity of the outcome.

The modelling would also not cover all the objectives identified by stakeholders for the modelling and analysis; for example, the improved risk management for generators and investors would not be addressed.

7.9.2 Central planner modelling

A central planning model attempts to minimise the total system costs to meet a particular objective, for example the reliability standard. The ISP is an example of a cost minimising, central planner model.

In such a model, the cost of dispatch would be modelled in the presence of transmission constraints, to determine a base case. The proposed model would then be modelled in order to determine a new total system cost. The difference between the new total system cost and the base case cost would provide an estimate of the benefits of implementing the model.

There are a number of problems in relation to the application of a central planner model to the proposed model. The modeller must make assumptions as to how costs are to be increased in the presence of transmission constraints. This assumption effectively assumes the answer that the model is trying to determine (i.e. that costs are greater in the base case).

This approach is ill-equipped to measure the operational and investment benefits from providing individual generators with more efficient price signals. This is because it takes no account of individual bidding behaviour, a critical component in any working model of the NEM.

The approach also fails to represent the risk appetite of generators and the impact on generator risk management under the proposed model. Costs are modelled, but not behaviour and responses to changes in the level of risk.

In failing to model risk and the impact on investment decisions, the modelling is unlikely to accurately describe the net benefit of the model, the likely impact of specific policy decisions or the distributional impact.

The central planner model would also be expensive and time-consuming to complete, with broadly similar costs and time lines to agent based modelling. The Commission, as a result, is not satisfied that the effort and time involved would be justified by a robust and comprehensive outcome in this instance.

7.9.3 Computational general equilibrium modelling

A Computational General Equilibrium (CGE) model is not a model of the electricity market, but instead a macroeconomic model of the economy as a whole. The modeller would assume changes in productivity in the electricity sector as a consequence of the proposed model, and use this to determine outputs such as GDP or employment changes.

The changes in productivity in the electricity sector are an input to this model, and are not modelled in their own right. As such, this model would assume the answer it is seeking to establish as an input, rather than deriving it as an output of the modelling.

The Commission does not consider that such an approach can provide meaningful analysis of the net benefits of the proposed model. It also fails to address specific policy design decisions as the electricity market itself is not modelled. For example, dispatch outcomes are not modelled, and so the impact of the model on the efficiency of dispatch cannot be determined.

QUESTION 30: ALTERNATIVE APPROACHES

Are there alternative approaches to a full quantitative model that stakeholders think should be considered that might avoid the pitfalls identified in the three approaches?

8 TRANSITION

Transitional processes would apply in the early years following implementation of the proposed model. These processes are necessary to ensure that the introduction of the model does not create sudden changes in the market, and to provide for a learning period.

Importantly, the transition process should not unnecessarily delay or dilute the efficiency benefits that the model is designed to promote. This chapter sets out our initial view on the transition for generators and TNSPs.

8.1 Transition for generators

There will need to be a transitional period in which incumbent generators would be granted, rather than pay for, financial transmission rights.

As outlined in the June directions paper, the objectives of these processes would be to:[92]

- mitigate any sudden changes to wholesale electricity prices or margins for market participants on commencement of the reform, in order to encourage and permit (existing and new) generators to acquire and hold the amount of financial transmission rights that they would choose to pay for
- give time for generators, transmission network service providers and other market participants to develop their internal capabilities to operate new or changed processes under the access reforms without incurring undue operational or financial risks during the learning period
- prevent abrupt changes in the amount of available financial transmission rights that could create dysfunctional behaviour or outcomes in financial transmission rights procurement or pricing.

The nature and length of any grandfathering arrangements represents a **trade-off.** On the one hand, were the arrangements too generous to incumbent generators (for example, the financial transmission rights provided excessive benefits, or were in effect for a long time), this could risk paying out too much to existing generators. In turn, this could also deter otherwise efficient investment in both generation and transmission.

Conversely, if the grandfathered rights are insufficient (in nature or length), this could expose incumbent generators to significant, unforeseeable regulatory risk. This too would be likely to deter, or increase the costs of, future investment. Thus, in ascribing the level of grandfathered rights, difficult judgements would need to be made as to how to best serve the long run interests of consumers, trading off the need to sufficiently protect existing investors.

92 AEMC, *Coordination of Generation and Transmission Investment - Access reform, Directions paper*, 27 June 2019, p. 96.

BOX 33: TRANSITION UNDER OPTIONAL FIRM ACCESS

The last time changes to the access framework were seriously considered in the NEM was in the AEMC's *Optional firm access, detailed design and testing* project, which the Commission was asked to undertake by the COAG Energy Council.

Under the model, it was proposed that existing generators would receive a level of transitional access. Details included that:

- At the date of commencement, existing generators would be allocated transitional access. Transitional access would function identically to other firm access rights, but would be procured differently and sculpted back over time.
- Some transitional access would be allocated to all existing generators for free. The remaining network capacity would be auctioned.
- There would be an ability for participants to secondary trade the transitional rights that they had received.
- There would initially be a period of five years where the transitional access, regardless of how it was procured, would remain at the level purchased.
- All transitional access, regardless of how it was procured, would be sculpted back over the subsequent ten years. As generators would have their transitional access sculpted back, they would have the right to purchase firm access through a renewal process that could represent a saving over the cost of firm access purchased in the standard procurement system.

We went to note in the final report for that review that implementing optional firm access did not meet the National Electricity Objective in the environment that existed in 2015 – but it could at some future time.

The Commission noted that if optional firm access were to be implemented at a later date, the transitional access arrangements would need to be reconsidered at that time, taking into account the above principles for transitional access allocation, and the market situation at that time.

The Commission agrees with the sentiments that it expressed in 2015. We consider that the transitional access model will need to be adapted given:

- the model for transmission access reform that is being considered now is significantly different to optional firm access. In particular:
  - there is no direct link between the purchase of financial transmission rights and transmission planning and investment decision-making
  - financial transmission rights are shorter in length.
- the NEM has evolved significantly since that time. For example, there is significantly higher proportion of renewable generators and significant market reforms have taken place.

Therefore, the work that was undertaken in Optional firm access may be instructive in considering transitional matters, but not definitive.

Source: AEMC, Optional Firm Access, Final Report - Volume 2, July 2015.

8.1.1 Grandfathering of access

The Commission is of the view that incumbent generators would need to be granted some level of financial transmission rights for free.

In response to the June directions paper, some generators and investors indicated that grandfathering arrangements should be made clearer to stakeholders.[93]

However, the Commission is of the view - as it was in June - that it is difficult to work out the form and length of the transitional financial transmission rights prior to developing the proposed access model in detail. It is impossible to work out an effective transition towards a model that is not yet clearly specified.

However, we recognise that this issue is important to stakeholders and therefore have set out the following considerations:

- The new arrangements should start somewhere close to a steady-state situation, where most of the network is covered by financial transmission rights arrangements. Transitional FTRs should approximate the implicit access that generators currently enjoy, based on how they use the network.
- Recognising the risk that generators' implicit access is currently at risk of being degraded over time (for example by the location of new generators nearby), transitional FTRs should be sculpted back over time.

This implies that existing generators would receive an amount of financial transmission rights for free that would taper off over time.

Once the level of grandfathering has been determined, there are strong arguments that FTRs should be allocated to the party that values it most, as quickly as possible. It therefore may be prudent to have a one-off auction to allow generators to buy and sell transitional FTRs from each other, or to allow this to happen in the first auction of any remaining fFTRs not allocated to incumbent market participants. This would seek to ensure that existing transmission capacity was efficiently allocated.

However, there are also arguments to suggest that holders of property rights often systematically overvalue those rights, holding on to them when they would be better off selling them. This is due to what has been dubbed the 'endowment effect'.[94] In this case, purchase prices are more efficient than selling prices; that is, forcing generators to relinquish their FTRs over time will lead to more efficient allocation than would be achieved by relying

93 Submissions to the June directions paper: HRL Morrison & Co, p. 3; Australian Energy Council, p. 12; CS Energy, p. 2; ENGIE, p. 2; Meridian Energy and Powershop, p. 6; TasNetworks, p. 7; AGL, p. 5; Infigen Energy, p.5.

94 See D Kahneman, JL Knetsch, and RH Thaler, 'Experimental Tests of the Endowment Effect and the Coase Theorem', Journal of Political Economy, vol 98, no 6, 1990, pp.1325-1348.

on secondary trading alone. Efficient FTR prices are particularly important in terms of facilitating efficient entry into the market.

> QUESTION 31: GRANDFATHERING OF ACCESS
>
> Do stakeholders agree with the proposed principles and approach?

8.2 Transition for transmission network service providers

As discussed in Chapter 6, the proposed model includes enhancing the existing service target performance incentive scheme for TNSPs to manage the network in line with *when* and *where* capacity is most valued by the market. The incentive would reflect more granular information being revealed from the dynamic regional pricing.

The enhanced incentive scheme should better align the risks that TNSPs face with those faced by market participants. For example, since settlement shortfalls would be based on the spot market price, the risks that TNSPs face would reflect better approximation of the market value of the congestion that is created (compared to the current tariffed market impact component penalty).[95] However, the risk that TNSPs would be exposed to under the enhanced STPIS should be no different to what they are currently exposed to.

Therefore, we consider that the enhanced operational incentive scheme for TNSPs could be put in place to apply to each TNSP as part of their next revenue determination in accordance with relevant guidelines and regulatory arrangements.

> QUESTION 32: TRANSITION FOR TRANSMISSION NETWORK SERVICE PROVIDERS
>
> Do stakeholders agree with our considerations for transmission network service providers in relation to transition?

95 This is because spot market prices can range from -$1,000 to $14,700 per megawatt hour. In contrast, the market impact component of the current STPIS scheme includes a relatively blunt measure of the value of transmission capacity; whereby TNSPs are incentivised to eliminate outage events with a market impact of over $10/MWh (i.e. well below the market price cap).

9 IMPLEMENTATION

This chapter sets out the proposed implementation approach for our proposed access model, including the introduction of dynamic regional pricing and financial transmission rights.

9.1 Background

In the June directions paper, we set out an initial intent to implement dynamic regional pricing and financial transmission rights in July 2022.[96] This view was based on the following considerations:

- Implementing dynamic regional pricing and financial transmission rights in one holistic stage may make adapting to the new regime simpler for market participants. In addition, the ability to purchase financial transmission rights would enable generators to more effectively manage the risks of local prices that diverge from the regional reference price when transmission congestion occurs.
- Implementing the access model sooner rather than later will maximise its intended benefits and allow generators to receive greater financial certainty over their investment.

We also considered that there was an in-principle case for greater information provision before 2022. For example, it may be possible for AEMO to publish the following information before the wider changes to the access regime come into effect:

- historic and forward-looking locational marginal prices
- information about when transmission network constraint equations bind.

9.2 Stakeholder views

In response to the directions paper, the AER expressed support for implementing dynamic regional pricing and financial transmission rights at the same time.[97] It agreed that concurrent implementation should also make the transition to the proposed access model simpler for stakeholders to navigate.

Many generators and networks were of the view that the proposed July 2022 implementation date may be too soon.[98] They considered that a greater amount of lead time would be needed to develop and test the proposed model before it is implemented. In addition, several stakeholders cited that implementation may be challenging alongside other framework changes currently under way such as five minute settlement.

96 AEMC, *Coordination of Generation and Transmission Investment - Access reform, Directions paper*, 27 June 2019, p. 94.

97 AER, submission to the directions paper, *Coordination of generation and transmission investment implementation- access and charging*, p. 1.

98 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, directions paper submissions: CitiPower, United Energy & Powercor, p. 1; AusNet Services, p. 3; Australian Energy Council, p. 1; CS Energy, p. 2; Delta Electricity, p. 2; Energy Networks Australia, p. 4; Energy Queensland, p. 2; Meridian Energy and Powershop, p. 5; Snowy Hydro, p. 7; AGL, p. 2.

9.3 Our views

Transmission access reform is needed sooner rather than later for the NEM to effectively evolve. Access reform is integrally linked with the key issues facing the market, which are affecting all types of market participants.

The Commission agrees with the view previously expressed by AEMO that four years is too long to wait to resolve the challenges facing the NEM.[99] That is why we proposed a date of July 2022 for implementation of the new access regime.

We are concious of stakeholder feedback that sufficient time is needed for the market to prepare to implement the model. However, in our view, the proposed access model is somewhat simpler now that we are not proposing to have financial transmission rights directly inform transmission planning.

Therefore, we are still of the view that July 2022 is appropriate for implementation. As with any change, the implementation date of the model will be finalised during the rule change processes next year, by which time AEMO will have been able to consider detailed costing and the extent of system changes that are required. The implementation date at that time will also be informed by the dates of other reforms that interact with this one.

QUESTION 33: IMPLEMENTATION

In light of the proposed access model specification put forward in this paper, do stakeholders have views on an appropriate implementation date?

99 AEMO, submission to the consultation paper, *Coordination of generation and transmission investment implementation- access and charging*, p. 4.

ABBREVIATIONS

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
Commission	See AEMC
COGATI	Coordination of generation and transmission investment review
COAG	Council of Australian Governments
DR	demand response
ESB	Energy Security Board
FTR	financial transmission right
ISP	Integrated System Plan
IR-TUOS	inter-regional transmission use of system
LAP	load aggregation pricing
LMP	locational marginal price
MCE	Ministerial Council on Energy
MLF	marginal loss factor
MNSP	market network service provider
NEL	National Electricity Law
NEM	National electricity market
NEMDE	National electricity market dispatch engine
NEO	National electricity objective
NERL	National Energy Retail Law
NERO	National energy retail objective
NGL	National Gas Law
NGO	National gas objective
NSA	network support agreement
NSG	Non-scheduled generation
OFA	Optional firm access
PPA	Power purchase agreements
REZ	Renewable energy zone
RIT-T	Regulatory investment test for transmission
RRN	regional reference node
RRP	regional reference price
SENE	Scale efficient network extensions
SRA	settlement residue auction
STPIS	Service target performance incentive scheme
TCAPA	Transmission connection and planning arrangements

TNSP	Transmission network service provider
TUOS	Transmission use of system

A ASSESSMENT FRAMEWORK

This appendix sets out the framework the Commission will use to consider:

- how access reform might improve coordination between generation and transmission investment
- whether changes to the regulatory framework and market design are needed to enable access reform to proceed in a manner consistent with the NEO.

A.1 The National Electricity Objective

The overarching objective guiding our approach is the National Electricity Objective (NEO). The Commission's assessment of any recommendations must consider whether the proposed recommendations promote the NEO. Similarly, with any related rule changes that may stem from this review, the Commission will have to consider whether the proposed rules promote the NEO. The NEO is set out in section 7 of the National Electricity Law (NEL), which states:

> "The objective of this Law is to promote efficient investment in, and efficient operation and use of, electricity services for the long-term interests of consumers of electricity with respect to:
>
> (a) price, quality, safety, reliability and security of supply of electricity; and
>
> (b) the reliability, safety and security of the national electricity system."

Based on a preliminary assessment of the issues raised by this review on the generation and transmission access regime, the Commission considers that the overarching promotion of **efficient investment, operation and use of electricity services**, as well as the areas of **price, reliability and security** are the relevant areas of the NEO for further consideration.

A.2 Principles of good market design

The Commission has set out a number of market design principles to guide the development of potential changes to market and regulatory arrangements that underpin the generation and transmission framework in the NEM. These principles were discussed in the technical working group, and reflect stakeholder feedback.

As noted in Chapter 3, the Commission welcomes the Australian Energy Council's assessment framework to assess congruency between different reforms under way that it has recently published. The Commission agrees with the AEC's assessment that the proposed COGATI reforms affect all four categories - wholesale markets, contracting, generation and networks.

However, the Commission notes that the initial assessment undertaken by the AEC was against the proposal in the directions paper (i.e. where the third pillar of reform was included). The Commission will consider how the framework could be applied to the proposed model set out in this paper.

A.2.1 Appropriate allocation of risks to parties best placed to bear them

Good market design allocates risk and accountability for market investment and operational decisions to parties who are most able to manage them efficiently and have the greatest incentives to do so.

A key objective of the COGATI reforms is to minimise the risk of consumers carrying the risk of inefficient transmission investment decisions. Solutions that allocate risks to market participants are preferred where practicable because market participants have commercial incentives to manage such risks in an efficient manner.

Risk allocation and the accountability for investment and operational decisions should rest with those parties best placed to manage them. Placing inappropriate risks on consumers, who are not best placed to manage these risks is likely result in higher prices while risk to market participants will only be passed on to consumers in terms of higher prices where competition permits.

Under arrangements where investment and operational decisions are made by a single entity such as a planner or system operator, risks are more likely to be borne by consumers. As a result, this single entity does not have sufficient commercial incentive to minimise costs (because the consumer tends to bear them instead), resulting in inefficiently high costs for consumers than they would be if the costs associated with decisions were incurred by market participants operating in competitive environments. Solutions that allocate risks to market participants, such as commercial businesses, who are better able to manage them are preferred, where practicable.

A.2.2 Promote signals that encourage efficient investment and operation of generation and load assets

Efficient market design arrangements maximise the provision of price signals that reflect the marginal cost of the provision of a particular product or service, as well as any positive or negative externalities, in order to encourage efficient decision-making by market participants in both investment and operational time-scales.

A key aim of any transmission access regime should be to provide appropriate locational signals to new generators such that they make entry and operational decisions that efficiently reflect the costs of generating and transporting electricity to consumers.

The right signals tend to lead to the minimisation of system wide costs. Price signals are preferred because they are the key signals that enable market participants to understand and incorporate the short-term and long-term costs of producing electricity into their commercial decisions. These signals would encourage prospective generators to establish their operations in locations where it would be efficient to do so and discourage them from establishing in locations where doing so would be less efficient. Appropriate price signals also provide incentives for market participants to operate in an efficient manner.

However, there may be other signals that can also be provided such as the greater provision of market information to participants.

A.2.3 Facilitating competition where feasible, and effective regulation where necessary

Competition promotes efficiency on a short-term basis by encouraging generators to offer prices that reflect production costs, as well as in the long-term by encouraging investment and innovation that supports the provision of cheaper electricity.

However, market design must also take into account the fact that no market is perfectly competitive, as well as any circumstances where the promotion of competition is impractical or not feasible.

In these cases, it is necessary to regulate and incentivise natural monopolies, such as TNSPs, to make efficient trade-offs between providing transmission services through additional investment in network expansion or through the use of operational (non-network) measures.

Such measures encourage TNSPs to provide the services demanded by their customers at the lowest sustainable cost.

A.2.4 Promoting simplicity, transparency and predictability

Any market design intended to reform the transmission framework should be simple, predictable and transparent, so that consumers, generators, TNSPs and regulators are adequately informed about the variables that affect investment and operation in the sector.

As a result, market participants would be able to make efficient investment and operational decisions that would minimise their transaction costs.

Such simplicity, transparency and predictability should also promote confidence in the market framework and encourage effective market participation.

A.2.5 Promoting the safe, secure and reliable supply of energy

Any new market design must take into account the need to support the safe, secure and reliable supply of electricity to consumers. Regulation may be required to safeguard these outcomes.

A.2.6 Maintaining a level playing field for different forms of technology and for market participants

Market design arrangements should be designed to account for a full range of potential market and network solutions. Market design should therefore focus on the goods that are being supplied, rather than the methods used to supply these goods.

Regulatory arrangements should be designed to take into account the full range of potential market and network solutions, as well as taking account of all possible technologies that could provide such solutions (e.g. generation or demand-side). They should not be targeted at a particular technology or business model, or be designed with a particular set of technologies in mind. Technologies are changing rapidly, and, to the extent possible, a change in technology should not require a change in regulatory arrangements.

Market design arrangements should also be designed to provide a level playing field for market participants. Market design reforms should provide transitional arrangements that mitigate adverse impacts on existing generators that made investment decisions based on the current regime, but also do not hinder the ability of new generators to enter the market.

A.2.7 Flexibility and adaptability

Transmission and generation frameworks must be designed to be flexible in response to changing market and external conditions, such as in the broader political landscape. These frameworks must also enable market participants to respond to such changes as they develop within the NEM.

Flexibility and adaptability are particularly important during times when major changes and other major reforms are occurring within the NEM. The NEM is currently experiencing rapid technological change. To the greatest extent possible, the framework delivers efficient solutions regardless of how the future pans out, rather than having to change the framework to adapt to a changing future.

Such frameworks seek to decentralise decision-making to the greatest extent possible, because market participants and customers typically have the information, tools and incentives to flexibly respond to changes in circumstances in ways that promote customers' long term interests.

B DYNAMIC REGIONAL PRICING AND SETTLEMENT

This appendix provides an overview of how dynamic regional pricing may change settlement.

B.1 Current dispatch and settlement arrangements

In the NEM, there are key differences between dispatch and settlement:

- Generators are dispatched[100] based on their offers to the market, their location and the physical characteristics of the network. Therefore, dispatch can be considered to be a local market clearing process.
- Generators are paid for energy dispatched at the regional reference price. This payment is directed through central settlement arrangements that are operated by AEMO. Therefore, settlement can be considered to be a regional market clearing process.

B.1.1 Dispatch arrangements

Load and generation need to physically balance at each point in the transmission system. NEMDE dispatches generators such that load and generation are balanced. It also dispatches generators in a manner that solves for the least cost way of meeting demand.

NEMDE is able to achieve this through determining the 'locational marginal price' of generation in each location. The locational marginal price is calculated by working out the cost (as proxied by the offer prices of local generators) of supplying an additional megawatt of electricity at a particular transmission node.

Generators are dispatched by NEMDE if they place offers at or below the locational marginal price of their transmission node. Generators with offers above the locational marginal price are never dispatched by the NEM dispatch engine. This is because these offers are above the marginal cost of supply and so would not result in total dispatch costs being minimised.

B.1.2 Settlement arrangements

Generators are paid for the production of energy by market customers. This occurs through the central settlement process that is operated by AEMO. Under the current settlement arrangements, all load and generation are paid the regional reference price for the amount of electricity they consume or dispatch, respectively.

Generators that are not dispatched in a given settlement period do not generate electricity and so do not receive payment i.e. these generators do not receive access to the regional reference price. Thus, revenue is a direct function of physical dispatch.

The regional reference price is determined just like any other locational marginal price. It represents the cost of supplying an extra megawatt of demand (as determined by generator offer prices) at the regional reference node. Therefore, settlement payments to generators can be considered to be the following:[101]

100 That is, given instructions about how much to generate at a particular point in time in order to meet demand.
101 Excluding the impact of losses.

BOX 34: CURRENT SETTLEMENT ARRANGEMENTS

Settlement$ = RRP x G **(1)**

Where:

G = Dispatched output

RRP = Regional reference price

However, we can also think about the current arrangements differently. Putting the concepts described above together, the above payment can be de-constructed into two settlement components:

- **Settlement against the LMP:** a generator is dispatched at its local node in accordance with its dispatch offer[102] and is paid its local marginal price for its output.
- **Settlement against the RRP-LMP differential**: for the quantity that it is dispatched, the generator also receives the difference between its local price and the regional reference price.

If there are no constraints on the transmission network within a region, a generator's locational marginal price would be the same as the regional reference price.[103] Because there is no congestion, supplying one more unit at the regional reference node could come from the local generator if it has the lowest marginal offer. This means that the price at the regional reference node must be the same as the price at the generator's local node.

However, when congestion arises, locational marginal prices diverge from the regional reference price to reflect the transmission constraints that are occurring at a particular time. For example, if there is a constraint on the network, it is expected that a more expensive generator will need to be dispatched in order to supply consumers. This will increase the regional reference price. This displacement will be at the expense of lower cost generators located behind a constraint.

Since load is settled at the regional reference price, differences between the locational marginal prices that generators receive and the regional reference price that load pays effectively result in intra-regional settlement residues. This way of thinking about settlement clarifies that under the existing arrangements, these residues are *implicitly* allocated to generators based on their dispatched output.

Adopting this perspective, an alternative mathematical representation of the current arrangements is set out in the box below. This could be considered to better reflect the underlying dispatch and settlement processes.

102 That is, dispatched if their offer is equal to or below the local price.

103 In the absence of losses.

BOX 35: ALTERNATIVE PERSPECTIVE ON CURRENT SETTLEMENT ARRANGEMENTS

$$Settlement\$ = Settlement\$_{Dispatch} + Settlement\$_{Residue} = LMP \times G + (RRP - LMP) \times G \quad \mathbf{(2)}$$

Where:

G = Dispatched output

LMP = Locational marginal price

RRP = Regional reference price

In this formulation, the second term, (RRP – LMP) x G, captures the current implicit allocation of intra-regional settlement revenues based on dispatched generation.

Note that this is mathematically identical to the more familiar equation 1 in the previous box.

These arrangements give rise to several commercial and operational concerns in the NEM today:

- As dispatched generators receive an allocation of the intra-regional settlement residues at no cost, locational signals to generators are diluted.
- As the allocation of settlement residues is based on dispatch, which can be affected by congestion, the allocated quantity is uncertain.
- As generators are effectively paid the regional reference price rather than locational marginal price, bidding and dispatch outcomes may be inefficient when congestion occurs.

B.2 Dispatch and settlement under dynamic regional pricing

As described above, a generator's dispatched output currently determines both:

- the quantity of generation for which the generator will receive the locational marginal price; and
- their share of the settlement residues that accumulate as transmission constraints arise and locational marginal prices within a region diverge.

If dynamic regional pricing were to be implemented, scheduled and semi-scheduled market participants would receive the locational marginal price at their transmission node for their dispatched output, rather than the regional reference price. As a result, the settlement residues that are currently *implicitly* allocated on the basis of dispatched output would need to be *explicitly* allocated on a different basis.

We are proposing that dynamic regional pricing is introduced at the same time as financial transmission rights. This would mean that the allocation of settlement residues would be based on the level of financial transmission rights held by generators, as shown in the box below.

BOX 36: SETTLEMENT UNDER DYNAMIC REGIONAL PRICING (WITH FINANCIAL TRANSMISSION RIGHTS)

$$Settlement\$ = Settlement\$_{Dispatch} + Settlement\$_{Residue} = LMP \times G + (VWAP - LMP) \times H$$
(3)

Where:

G = Dispatched output

H = Financial transmission rights quantity

LMP = Locational marginal price

VWAP = Volume weighted average price

*Note that we are proposing that the financial transmission rights are **options** contracts, and so only pay out if the RRP is greater than the LMP. If so, the holder of the financial transmission right would not receive a negative payment (that is, have to make a payment) if LMP is greater than RRP. Note that the proposed model replaces the current regional reference pricing method with a volume weighted average price.*

An advantage of decoupling the allocation of intra-regional settlement residues from dispatch[104] is that it would remove the incentives for generators to engage in 'race to the floor' bidding behaviour, which currently creates costs to consumers.

Under dynamic regional pricing:

- If the generator's offer is *less* than the locational marginal price at its node[105], it will be dispatched and achieve an operating profit margin equivalent to the difference between its cost and the locational marginal price.[106]
- If its offer is *above* the locational marginal price, it will not be dispatched.[107] However, this should be preferable to being dispatched and receiving a locational marginal price which will not cover operational costs.

An alternative way to think about dynamic regional pricing is that it enables a more efficient allocation of congestion risks and costs. Under the current arrangements, generators currently face *volume* risk. Volume risk is the risk that, due to transmission constraints, generators may not be dispatched despite their offer price being less than the regional reference price. Under dynamic regional pricing, generators would no longer face this volume risk, as dispatch would be a direct function of their offer price and the locational marginal price at their local node.

However, generators would face *price* risk. Price risk is the risk of the generator's locational marginal price being different from the regional reference price. This risk will occur when

104 In equation 3 above, this is expressed by replacing the 'G' in the second term of equation 2 with an 'H').

105 Or equal to the locational marginal price, if it is the marginal generator.

106 In addition to a share of the settlement residue if they hold financial transmission rights.

107 But may still receive a share of the settlement residue depending on whether it holds financial transmission rights.

transmission congestion is present. The implementation of financial transmission rights through the proposed access model provides a means for generators to manage this price risk.

C INTERNATIONAL EXPERIENCE - MARKET POWER MITIGATION

The market arrangements in New Zealand and ERCOT illustrate two different approaches to mitigating local market power in a market with locational marginal pricing.

C.1 New Zealand

The New Zealand wholesale market design includes two features that assist with the mitigation of market power:

1. Defined standards of trading conduct provide for an ex post evaluation of bidding behaviour by pivotal suppliers and potential remedies if these standards are breached.
2. If an undesirable trading situation arises, the Electricity Authority has broad powers to take action to ensure that the integrity of the wholesale market is preserved, which may include ex post modification of pricing outcomes.

C.1.1 Standards of trading conduct

Clause 13.5 of the Electricity Industry Participation Code (2010) sets out trading conduct provisions for market participants. The provisions were established in 2012, with the objective of promoting outcomes that are consistent with workable competition.

A primary driver of the provisions was to address potential efficiency losses that could occur in pivotal supplier situations. The provisions contain:

- Clause 13.5A, which requires *all* generators and ancillary service providers (not only pivotal suppliers) to observe a high standard of trading conduct when submitting or revising an offer.
- Clause 13.5B, which sets out safe harbour provisions that define when a generator complies with 13.5A:
  - The generator offers all available generation capacity to the market.
  - If the generator decides to submit or revise an offer, it does so as soon as possible.
  - If a generator is pivotal (i.e., required to meet demand at one or more nodes):
    - The generator's offers do not result in a material increase in the final price at any node at which the generator is pivotal, compared to the final price in an immediately preceding trading period or other comparable trading period in which the generator was not pivotal.
    - The generator's offers are generally consistent with offers it has made when it was not pivotal.
    - The generator does not benefit financially from an increase in the final price at a node in at which it is pivotal.

Since the provisions were implemented, there have been two compliance investigations, both of which related to alleged misuse of a pivotal supplier position. These cases have led to a review by the Market Development Advisory Group (MDAG).

C.1.2 Undesirable trading situations

An undesirable trading situation (UTS) is defined as *"any situation that threatens, or may threaten, confidence in, or the integrity of, the wholesale market, and that, in the reasonable opinion of the Authority, cannot satisfactorily be resolved by any other mechanism available under the Code"*.[108]

In such cases, the Authority may take action to correct the UTS, including by directing that specific trades should be settled at a specified price. The UTS provisions can only be used if there is no other remedy available under the code. However, this excludes remedies that may be applied in the context of a breach of the trading standard provisions described above.

To date, the UTS mechanism appears to have been used to modify settlement prices on only two occasions. The most notable example was in 2011, where interim spot market prices exceeded NZ $19,000/MWh at some nodes.[109]

The UTS Committee found that this was the result of a market squeeze, which placed generator Genesis in a net pivotal position.[110] At the same time, inaccuracy in the pricing forecast failed to consistently predict that high interim prices were likely to result from this situation, providing other market participants with limited ability to respond.

The Committee found that allowing the high prices to stand could damage confidence in the market, such that *"trading on the market may be threatened and the adverse financial impact on some parties may preclude the maintenance of orderly trading or the proper settlement of trades"*.

The Committee determined that the appropriate response was to establish final prices on the basis on an assumed demand-side response price of NZ $3,000/MWh. Consequently, the dispatch model was re-run with Genesis' offer set to $3,000/MWh in order to determine final settlement prices. Conceptually, this reflected that if load had adequate information in relation to Genesis' intended bidding behaviour, Genesis would have been constrained by the value to load of being curtailed (i.e., the economic alternative available to load).

The Committee considered the possibility that resetting Genesis' offer price may have the effect of creating a price cap or distorting incentives in New Zealand's energy-only market. However, the Committee emphasised that its decision was specific to the circumstances, and that similar circumstances are expected to arise only rarely. The Committee's decision was subject to an unsuccessful High Court challenge by Genesis.

C.2 ERCOT

The Electricity Reliability Council of Texas (ERCOT) is the independent system operator for the US state of Texas. ERCOT's wholesale electricity market has locational marginal pricing.

ERCOT's dispatch software includes an automatic bid mitigation mechanism that aims to limit the ability of generators to influence market prices when network constraints arise. This is

108 Clause 5.1 of the New Zealand Electricity Industry Participation Code.

109 The other occasion was to correct an input error by Transpower in the dispatch model.

110 The Authority did not find that Genesis had engaged in misleading or deceptive conduct.

considered an important factor in mitigating localised market power in the context of nodal pricing.

Specifically, when a transmission constraint binds, local generation resources may be required to ensure reliability. The concern is that absent mitigation, in this situation a generator could inflate its offers in order to secure a high price. The intent of the offer mitigation is to prevent inflated offers when constraints result in limited competition at a local node.

The steps in the offer mitigation process are:

1. Network constraints are categorised as either 'competitive' or 'non-competitive'. A competitive constraint meets the conditions that:
   a. The Herfindahl-Hirschmann Index (HHI) of capacity on the import side of the constraint is less than 2,000.[111]
   b. The capacity of a market participant (and their affiliates) is not pivotal. That is, their capacity is not required to meet demand on the import side of the constraint. This condition excludes nuclear generation and the minimum energy capacity of baseload coal power stations.
2. A reference price is then set by simulating a market dispatch that includes only competitive constraints (i.e., non-competitive constraints are removed).
3. Offers are then capped at the maximum of the reference price or a 'mitigated offer cap'. This is the larger value out of either the operating cost of a marginal gas plant, or the resource's verifiable operating costs (plus a multiplier).
4. Generators are paid at the resulting *clearing price* at their node, which may be higher than the offer cap.

There are concerns that in some cases the bid mitigation process may reduce the ability of resources to earn a return for scarcity.[112] This has been highlighted in relation to 'reliability unit commitment' (RUC) resources, who may be required to run out of merit order to maintain reliability. To the extent that a RUC resource alleviates local congestion, it may fail the local market power test outlined above and therefore be subject to offer mitigation.

111 The HHI is a measure of market concentration.

112 For examples, see page 50 of https://sites.hks.harvard.edu/fs/whogan/Hogan_Pope_ERCOT_050917.pdf.