Optional Firm Access

A REPORT PREPARED FOR THE NATIONAL GENERATORS FORUM

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Executive summary

Frontier Economics has prepared this report for the NGF critiquing the Optional Firm Access (OFA) proposal put forward by the AEMC in the context of its Transmission Frameworks Review. The OFA proposal combines a form of generator nodal pricing with a form of financial transmission rights described as 'firm access rights'. Under the proposal, when transmission constraints bind, generators with firm access rights would receive congestion rentals sufficient to put them in a similar position to as if they received the RRP in respect of their applicable firm access quantity and standard.

Increased centralisation of decision-making under the OFA proposal

The greatest drawback of the OFA proposal concerns the methodology for pricing firm access rights. As well as being extremely complex and abstract, the methodology implies a profound centralisation of decision-making power over the planning of, and investment in, new generation and transmission infrastructure compared to the present arrangements. Such centralisation flies in the face of one of the key claimed benefits of the OFA proposal – that it represents a 'market-led' approach to development of the transmission network that should achieve a higher level of co-optimisation between generation and transmission development.

Under the existing transmission planning and regulatory arrangements, prospective investors in new generation face a number of locational signals that promote economic efficiency. These include availability of fuel and water, marginal loss factors and the risk of being constrained-off. The AEMC considers these signals inadequate to ensure efficiency because:

- TNSPs lack accurate information about future generation costs – which can lead to imperfect co-optimisation between investment in transmission and generation and
- The lack of generator transmission charges means that investors do not account for the impact of their locational decisions on transmission network costs

However, the locational signals provided under the current transmission planning arrangements are more powerful than is commonly assumed. These signals arise through the operation of the RIT-T, including participants' expectations of how the RIT-T will be applied in future. Generators will tend to find it profitable to locate in areas where the TNSP considers that new generation will be built and hence has augmented or will augment the transmission network, thereby reducing actual and expected congestion. Likewise, generators will choose not to locate in areas where transmission will not be augmented or where generation investment could be stranded by transmission investment elsewhere. The AEMC acknowledges that TNSPs' current planning processes send implicit locational signals to generation investors.

By contrast, locational signals under the OFA proposal would be based on prices for firm access rights. These prices would, in turn, be based on the outworkings of a TNSP's planning model. This means that the TNSP's prior and unconsulted views of where generation is likely to locate in future will tend to drive locational differences in firm access prices, other things being equal. Moreover, the role of TNSPs' views of future generation development will become even more important under the OFA model than they are at present. Accordingly, the notion that the OFA proposal promotes 'market-led' investment decision-making is false. The OFA proposal simply promotes generation investment in line with the TNSP's prior expectations.

Governance and good regulatory practice

The OFA proposal gives rise to a number of interdependent concerns about appropriate governance and good regulatory practice.

First, the proposed process for defining the normal operating conditions (NOCs) under which firm access standards (FASs) would be scaled down gives TNSPs strong incentives to define these conditions very conservatively. It is difficult to see how AEMO and generators could prevent this from occurring. The involvement of the AER would be necessary to ensure TNSPs were appropriately accountable for maintaining transmission network availability. However, this would effectively put the AER in a position where it would have to arbitrate on the design of a highly complex performance incentive regime that applied in respect of *each and every transmission flowgate* in the NEM.

Second, the derivation of firm access right prices and payment profiles would be extremely complex and abstract, which raises concerns about its transparency and the scope for manipulation of access prices. This concern applies in different ways to the pricing of access to reliability generators, non-reliability generators and existing generators.

Third, while there are some reasons for why the institution responsible for access pricing should be the TNSP, the AER would need to occupy a significant auditing role. Alternatively, if access pricing were determined by a centralised body such as the National Transmission Planner, this could make the process much less effective and timely.

Fourth, the requirement for TNSPs to examine and approve trades of firm access rights may create incentives for TNSPs to disallow trades on spurious grounds in the hope or expectation that the generator seeking to acquire rights would then approach the TNSP to augment the network to achieve the same outcome. If successful, this would boost the TNSP's regulated asset base and allowable revenues from the provision of prescribed transmission services.

Fifth, the role of the RIT-T under the OFA proposal is somewhat unclear. Depending on how the RIT-T was applied, it could either provide a much weaker check on over-investment than at present or it could lead to substantial delays in providing firm access offers.

Finally, the approach to managing firm access application queues under the OFA proposal is unclear. If applied strictly, it could lead to wildly varying prices for firm access rights depending on potentially how many days, hours or even minutes a generator made an access request to the TNSP ahead of other applicants. If applied more loosely, the identity and requirements of other applicants might need to be disclosed to enable applicants to properly assess the assumptions behind the prices they were offered. This would raise concerns about commercial confidentiality.

Issues the OFA proposal does not overcome

Other than providing locational signals to generators, the OFA proposal seeks to address a number of purported flaws in the current NEM design, including lack of firm financial access to support forward contracting, 'disorderly bidding' and a lack of firm inter-regional rights. However, the OFA proposal fails to properly address each of these issues.

First, whether the level of forward contracting would increase under the OFA proposal relative to the status quo is ambiguous. Firm generators may contract more than they do at present; but non-firm generators are likely to contract less.

Second, as is the case now, access rights under the OFA proposal would not be fully firm under all circumstances. Whenever system conditions deviated from system normal, firm access rights would be scaled down to avoid subjecting the TNSPs to financial risks they could not manage. Consequently, holders of firm access rights would still need to anticipate being non-firm under many conditions.

Third, because of the incentives created under the OFA proposal, it is unclear whether non-cost-reflective bidding would reduce as anticipated. Even if disorderly bidding did reduce, the effect on dispatch efficiency would be ambiguous. Furthermore, the costs of dispatch inefficiency in the NEM due to disorderly bidding have previously being estimated as being relatively small.

Fourth, the scope for firm inter-regional rights (FIRs) under the OFA proposal adds further complexities that give rise to a number of issues and concerns. For example, the realistic quantity of existing inter-regional rights likely to be available to participants is very limited or could become very limited. Further, it is far from clear that basing interconnector augmentation decisions on the expressed willingness of participants to pay for FIRs would result in efficient augmentation. Finally, the process of TNSPs bidding for FIRs may create circularity and indeterminacy problems. This is because TNSPs may find it impossible to bid for FIRs without undertaking a RIT-T analysis, which itself would require assumptions to be made about interconnector augmentation in the absence of the TNSP's bid.

Conclusion

Contrary to its stated intentions, the OFA proposal implies a profound centralisation of decision-making power over the planning of and investment in new generation and transmission infrastructure compared to the present arrangements. This represents a clear and unavoidable drawback of the proposal and reason enough for its abandonment.

The proposal also gives rise to numerous governance and implementation issues. Minimising the harm from these issues is likely to require the close involvement and attention of the AER. However, not only would this place enormous demands on the regulator, it would be likely to slow the process of conferring and managing firm transmission rights.

Finally, the OFA proposal does not appear likely to achieve even its most basic objectives – those of encouraging derivative contracting and eliminating non-cost-reflective generator bidding behaviour.

1 Introduction

1.1 Background

Frontier Economics has prepared this report for the National Generators Forum (NGF). This report critiques the Optional Firm Access (OFA) proposal put forward by the Australian Energy Market Commission (AEMC) in its Second Interim Report[1] for the Transmission Frameworks Review (TFR). Details of the OFA proposal are contained in the Technical Report[2] accompanying the Second Interim Report.

This report assesses the OFA proposal against the National Electricity Objective. More specifically, this report reviews the claimed benefits of the OFA proposal outlined in Box 4.1 of the AEMC's Second Interim Report, including the merits of the proposed Firm Interconnector Rights.

1.2 Outline of the OFA proposal

1.2.1 Objectives

The objectives of the OFA proposal are set out in section 3.2.1 of the Second Interim Report. These objectives principally refer to overcoming certain purported flaws in the existing market design and transmission pricing arrangements – namely:

- The lack of certainty of dispatch faced by generators when there is congestion, compounded by the inability of generators to obtain firm access even when they fund augmentations of the transmission network and
- The lack of clear and cost-reflective locational signals for generators such that their locational decisions do not take into account the resulting transmission costs[3]

Section 3.2.1 goes on to highlight the problems that the AEMC considers result from these flaws, including non-cost-reflective generator bidding and non-co-optimised generation and transmission development. Separately, the AEMC notes that TNSPs currently lack incentives to maximise network availability when

1 AEMC 2012, *Transmission Frameworks Review, Second Interim Report*, 15 August 2012, Sydney (Second Interim Report).

2 AEMC 2012, *Transmission Frameworks Review, Technical Report: Optional Firm Access*, 16 August 2012, Sydney (Technical Report).

3 Second Interim Report, p.20.

it is most valuable due to a lack of financial exposure to the costs of unavailability.

Box 4.1 of the Second Interim Report suggests that that the OFA proposal would offer a number of improvements over the existing arrangements, including:

- Improved support for a deep and liquid contract market – by providing a mechanism for firm access and firm inter-regional access
- More efficient investment in generation and transmission by providing cost-reflective locational signals for new generation and market-led development of the transmission network within and between regions
- More efficient dispatch of generation
- More efficient operation of transmission networks[4]

1.2.2 Key features

The OFA proposal combines a form of generator nodal pricing with a form of financial transmission rights described as 'firm access rights'. Under the proposal, when transmission constraints bind, generators with firm access rights would receive congestion rentals sufficient to put them in a similar position to as if they received the regional reference price (RRP) in respect of their applicable firm access quantity and standard.

The Technical Report explains that access rights under the OFA proposal would not be fully firm under all circumstances.[5] Whenever system conditions deviated from system normal, firm access rights would be scaled down to avoid subjecting the TNSPs to financial risks they could not manage. This means that even generators with a particular volume of firm access rights may not be 'made whole' with respect to the RRP in relation to that volume of rights.

The pricing of firm access rights would be based on a 'long-run incremental cost' (LRIC) methodology.[6] This methodology seeks to charge generators seeking firm access rights the cost of notionally 'bringing forward' transmission investment to enable those rights to be satisfied. This is discussed in more detail in section 2.2 of this report.

The optional nature of access rights under the OFA proposal means that generators would not be obliged to procure firm access rights to any level or at all. However, if generators chose to remain or become non-firm, they may only receive their local nodal price under conditions of binding constraints.

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4 Second Interim Report, p.45.

5 Technical Report, pp.22-23, 30-36.

6 Second Interim Report, pp.32-35.

The Second Interim Report highlights that under the OFA proposal, existing generators would be allocated transitional firm access rights free of charge.[7] The level of firm access allocated to existing generators would take account of historical levels of 'effective' access. These transitional rights would be 'sculpted' back over time and eventually expire, after which existing generators would be able to procure firm access rights upon payment of a charge.

An additional aspect of the OFA proposal is that generators and retailers would be able to procure firm interconnector rights (FIRs), which would entitle them to a quantity of inter-regional congestion rentals.[8] Once again, the congestion rentals provided under FIRs would be scaled down under non-system normal conditions. The purchase of FIRs would fund inter-regional network expansions.

1.3 Structure

The remainder of this report is structured in a manner that highlights the key shortcomings of the OFA:

- Section 2 explains how the OFA proposal promotes more centralised – rather than more market-driven – planning and development of the transmission network and generation investment
- Section 3 highlights the governance and implementation issues and costs arising from the OFA proposal
- Section 4 discusses the shortcomings of the OFA proposal in relation to some of the key issues it is intended to address – namely:
  - Lack of firm financial access for generators
  - Non-cost-reflective generator bidding causing economically inefficient dispatch and
  - Lack of firm inter-regional access rights

7 Second Interim Report, pp.38-39.

8 Second Interim Report, pp.39-44.

2 Increased centralisation of planning and investment

The greatest drawback of the OFA proposal concerns the methodology for pricing firm access rights. The methodology is extremely complex and abstract, as discussed in section 3.2.1 below. More importantly, the methodology implies a profound centralisation of decision-making power over the planning of, and investment in, new generation and transmission infrastructure compared to the present arrangements. In our view, such centralisation flies in the face of one of the key claimed benefits of the OFA proposal – that it represents a 'market-led' approach to development of the transmission network that should achieve a higher level of co-optimisation between generation and transmission development.

The best way to demonstrate the centralising tendencies of the OFA proposal is to compare the locational signals provided under the proposal to the signals provided by the current wholesale pricing and network planning arrangements. This section:

- Outlines the signals provided under the current transmission planning arrangements and the role of TNSPs' assumptions in influencing those signals (section 2.1)
- Outlines the signals provided under the OFA proposal and the role of TNSPs' assumptions in influencing those signals (section 2.2) and
- Compares and contrasts the degree of centralisation inherent in both regimes (section 2.3)

2.1 Signals under the current arrangements

Under the existing transmission planning and regulatory arrangements, prospective investors in new generation face a number of locational signals that promote economic efficiency. These signals include:

- The availability and cost of fuel and water at different locations
- Exposure to marginal loss factors (which over-recover average losses by a factor of approximately two)
- The risks of being constrained-off due to transmission congestion at different locations
- The need of thermal generators for appropriate 'airsheds'
- The difficulty of obtaining planning permission for generators near build-up areas due to environmental controls or lobbying

- Regulated transmission investment decision-making pursuant to the RIT-T process and
- Payment of connection costs, which can comprise extensions that do not satisfy the RIT-T

The first three of these are fairly uncontroversial and accepted by the AEMC.

The AEMC's key contention is that the transmission investment planning arrangements based around the RIT-T do not properly signal the long term costs of transmission, potentially distorting both generation and transmission investment decisions. This view is discussed in more detail below.

2.1.1 AEMC's view of deficiencies in existing arrangements

The AEMC's view of the deficiencies of the current arrangements appears to be based on two separate but related ideas.

The first idea is that TNSPs lack accurate information about future generation costs. This lack of information can lead to imperfect co-optimisation between investment in transmission and generation. The Second Interim Report states:

> Network planning requires TNSPs to predict the least-cost combination of generation and transmission to meet forecast load, and to plan the network accordingly. It can potentially result in imperfect co-optimisation: a TNSP knows the costs of transmission, but has imperfect information regarding the costs of generation. The TNSP's transmission investment decisions may have an effect on generators' investment decisions, by reducing congestion in certain parts of the network, and therefore encouraging generator investment in those areas. This creates a bias towards the generation and transmission development path towards that which the TNSP predicts, even where a lower cost combination exists.[9]

The AEMC notes that the extent to which the current regime produces imperfectly co-optimised investment, the costs are borne largely by end-use consumers, who have only limited influence on these investment decisions.

The AEMC's second idea is that the current lack of generator transmission charges means that investors do not account for the impact of their locational decisions on transmission network costs. According to the AEMC, this may also increase the risk of non-co-optimised (inefficient) investment. For example, while a new gas-fired generator would benefit from proximity to a gas pipeline, it does not currently have to pay for "the cost of transmission investment that may be required to support its locational decision."[10]

The OFA proposal appears to be driven by the view that addressing the second issue (lack of shared network generator transmission charges) will effect a

9 Second Interim Report, p.49.

10 Second Interim Report, p.50.

decentralisation of transmission planning that will overcome the first issue (poor TNSP information about generation costs).

2.1.2 Signals provided by the RIT-T

The locational signals provided under the current transmission planning arrangements are more powerful than is commonly assumed. These signals arise through the operation of the RIT-T, including participants' expectations of how the RIT-T will be applied in future. The importance of the RIT-T lies in how it is used by TNSPs to determine where and when transmission investment ought to be undertaken to ensure reliability standards are maintained. Generators will tend to find it profitable to locate in areas where the TNSP considers that new generation will be built and hence has augmented or will augment the transmission network, thereby reducing actual and expected congestion. The AEMC acknowledges that TNSPs' current planning processes send implicit locational signals to generation investors. Indeed, this is what lies behind the AEMC's concern that TNSPs' lack of information about generator costs can result in poor co-optimisation between generation and transmission investment.

The issue is therefore not the *existence* of signals created by the RIT-T, but the *integrity* and *appropriateness* of those signals as compared to the signals provided by alternative arrangements such as the OFA proposal.

Before undertaking this comparison, it is worth first illustrating how the RIT-T sends locational signals. Consider the following stylised example:

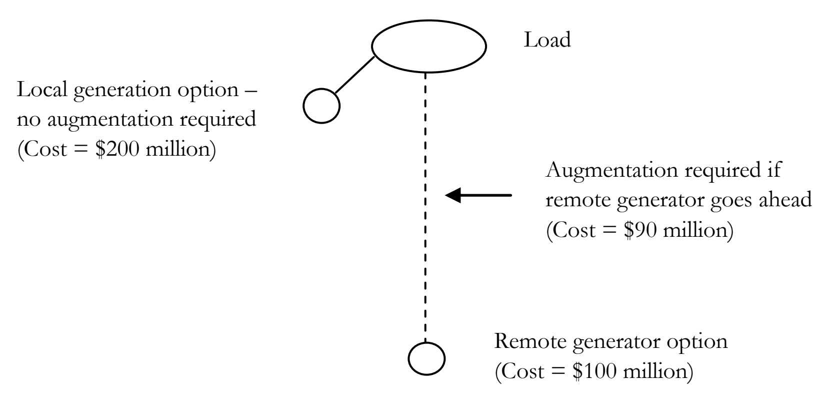
- Satisfaction of reliability standards requires additional supply to meet demand
- Investors have a choice between two locations for generation investment, described as 'local' and 'remote'
- Assume that:
  - The expected pattern and duration of power output of a new generator at both locations is the same
  - The operating costs of a new generator at both locations is the same and hence ignored for the remainder of the example
  - Capital costs at the local location are $200 million
  - Capital costs at the remote location are $100 million
  - If the generator locates locally, no transmission investment is necessary
  - If the generator locates remotely, $90 million of (non-lumpy, right-sized) transmission investment is necessary

These data are represented in Figure 1 below.

In considering whether it ought to invest in transmission to facilitate power flows from the remote generation option, the TNSP is obliged to undertake the RIT-T.

Under the RIT-T, the TNSP needs to compare the combined cost of generation and transmission at the remote location with the cost of generation at the local location. Contrary to the view expressed in the Technical Report, the TNSP does not simply consider which option yields the lowest transmission cost.[11] This is because under the RIT-T, a TNSP needs to consider the full 'market benefits' of an augmentation option and its alternatives.[12] In the context of this example, the TNSP needs to consider which option yields the larger net market benefit or the smaller net market cost, taking into account the total costs of transmission and generation (as well as other variables such as the degree of load shedding etc).

Figure 1: Locational signals from the RIT-T



Source: Frontier Economics

Given the example figures above, the TNSP would find that it was appropriate to undertake the augmentation because the combined generation and transmission cost of power from the remote option ($190 million) was lower than the cost of power from the local generation option ($200 million) – see Table 1.

Table 1: Transmission versus local generation – relative costs

Option	Includes	Total component costs ($m)	Total option costs ($m)
Transmission	Augmentation	90	190
	Remote generation	100	
Generation	Local generation	200	200

Source: Frontier Economics

11 Technical Report, pp. 40 (footnote 56) and 87.

12 AER, *Regulatory investment test for transmission, Final*, June 2010, clause (1), p.3.

Increased centralisation of planning and investment

The proponent of a generation investment would have an incentive to make such calculations internally, even before the RIT-T was applied to the augmentation by the TNSP. For example, before investing in the remote generation option, a proponent would have an incentive to conduct the analysis to gain some confidence that the augmentation would satisfy the test and proceed. Likewise, before investing in the local option, an investor would have an incentive to conduct the analysis. In doing so, it would find that it was not worthwhile to develop the local option, as the augmentation (along with the remote generator option) would be likely to go ahead and harm its proposed project.

Alternatively, if the capital cost of the remote option was higher (say, $120 million) and combined with the cost of the augmentation ($210 million) was more than the cost of the local generator option ($200 million), neither the augmentation nor the remote generator would proceed – see Table 2.

Table 2: Transmission versus local generation – relative costs

Option	Includes	Total component costs ($m)	Total option costs ($m)
Transmission	Augmentation	90	210
	Remote generation	120	
Generation	Local generation	200	200

Source: Frontier Economics

If the investor undertook similar analysis, it would realise that the local project was the most beneficial and should proceed, given that the augmentation was unlikely to go ahead and compromise the viability of its project. Similarly, a proponent of the remote generator would realise that it was pointless to develop such a plant.

In this way, prospective investors' expectations of how the RIT-T will be applied in the short and the long terms should provide investors with positive (albeit imperfect) locational signals.

2.2 Signals under the OFA proposal

2.2.1 Access pricing methodology

The Technical Report explains that under the OFA proposal, TNSPs would be required to change the way they planned and developed their networks. Whilst TNSPs are presently obliged to plan to satisfy reliability standards, under the OFA proposal, TNSPs would be obliged to plan their networks in a manner that also satisfied the anticipated demand for firm access rights. As a consequence, the pricing of firm access rights would be based on the present value of the costs of modifying or bringing forward future transmission investments to ensure that dispatch outcomes could underwrite the financial firmness of the rights allocated.

Simply put, the price of firm access rights would be:

- The NPV cost of forecast transmission investment given the need to underwrite the financial firmness of the access rights *less*
- The NPV cost of forecast transmission investment in the absence of the need to underwrite the financial firmness of the access rights

The determination of forecast transmission investment under both of these states of the world would be based on the outworkings of an 'element-based expansion model'. This model would first be used to derive a 'baseline expansion plan' of transmission investment for a particular branch element (such as a transmission line or network transformer). The baseline expansion plan would take into account:

- Initial spare capacity on the element
- Annual flow growth on the element based on expected load growth, the need to maintain reliability standards and expected future firm access applications
- Lumpiness, reflecting the relative size of incremental capacity expansions

The element-based expansion model would then be used to determine a 'modified expansion plan'. This modified plan would reflect the impact of the request for firm access rights on expected transmission investment, taking into account:

- Incremental usage/flow on the network element due to increased dispatch of generation consistent with the access rights and
- Term of the access rights being sought

Figures 6.1 and 6.2 in section 6.2.1 of the Technical Report illustrate the process of comparison between the baseline and modified expansion plans.

According to the AEMC:

> The OFA model would create a clear and cost-reflective locational signal for new generation investment that is currently missing in the NEM.[13]

The next section questions the purported market basis of locational signals under the OFA proposal.

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13 Technical Report, p.50.

2.2.2 Role of TNSPs' views in pricing OFA

One of the key issues with the OFA proposal is the pivotal role played by TNSPs' views of the world in determining prices for firm access rights.

The significance of TNSPs' views arises directly as a result of the way in which access prices are calculated using the element-based expansion model.

As noted above, both the baseline and the modified expansion plans would be developed by the relevant TNSP. Both exercises would be extremely subjective, with the calculated access price highly dependent on the TNSP's assumptions regarding future generation plantings and power flows in different locations into the distant future. If the TNSP made assumptions that turned out to be wrong, it would imply that the access prices charged to firm access seekers would also have been wrong. To the extent those prices had influenced investment decisions, those decisions would be less efficient as a result. Ultimately, generators and end-use consumers would bear the cost of these inefficiencies.

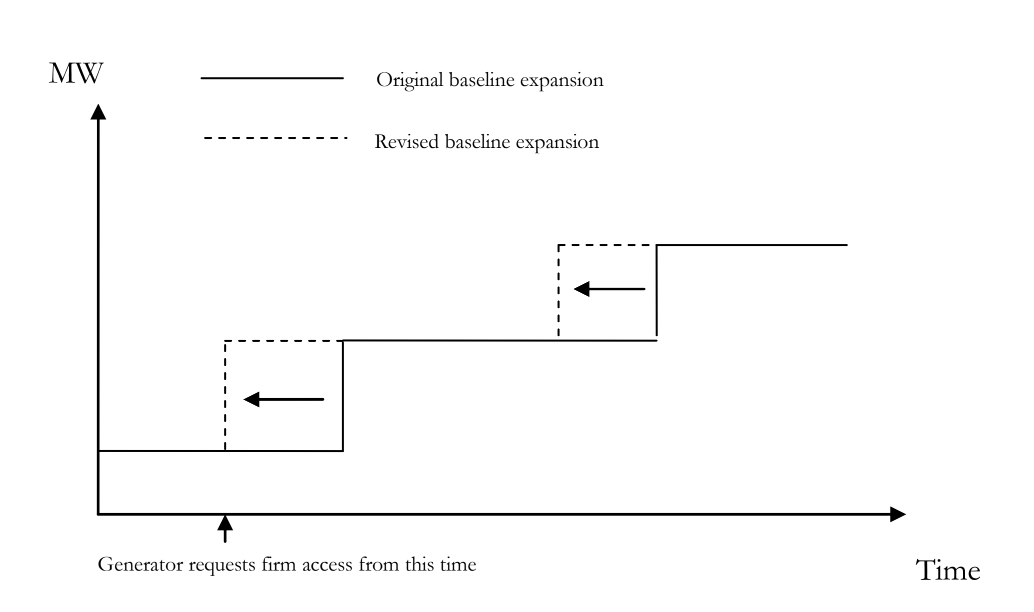
Consider the following example:

- Two potential locations of new generation investment are available, A and B
- Both locations are exactly as far from load as one another and augmentation costs from the RRN to both locations are the same
- Spare transmission export capacity from both locations is currently identical
- A new generator proponent requests the same volume of firm access rights at both locations

Under these conditions, the access prices provided by the TNSP to the generator proponent will only differ to the extent that the TNSP considers that baseline transmission development at the two locations will differ.

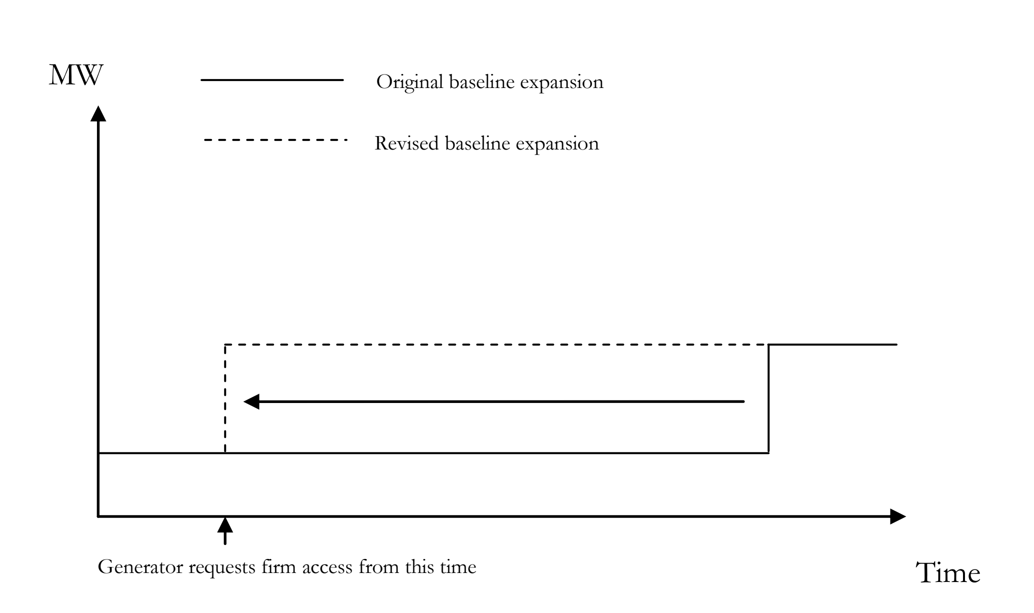
Now assume that the TNSP considers that fuel costs are lower at A than B. As a consequence, the TNSP expects that more generation development will occur in future at A than at B. This means that the baseline expansion for branch elements to location A (Figure 2) will look quite different to the baseline expansion for branch elements to location B (Figure 3).

Figure 2: Example baseline expansion plan to location A



Source: Frontier Economics

Figure 3: Example baseline expansion plan to location B



Source: Frontier Economics

Due to the 'lumpiness' of transmission investment relative to the size of new increments of generation, an application for firm access at location A would do less to bring forward estimated transmission investment than an otherwise identical application at location B. As a result, the price for firm access at location A would be lower than the price at location B. In the terminology of the

Technical Report,[14] the price of access at B would approximate a deep connection charge whereas the price at A would be closer to a LRMC charge.

The important point to note is that the *only* difference between the locations that can explain the difference in charges is that the TNSP regards location A as more promising for generation investment than location B. Hence, it is the TNSP's views about the future that creates the differential locational signal. Such a signal is neither market-based nor market-led – it is an implication of a centralised planning process.

The next section compares the role of TNSPs' views of future generation investment under the OFA proposal and the current arrangements.

2.3 Comparison of the role of TNSPs' views

As shown in the above sub-sections, both the current transmission arrangements and the OFA proposal provide locational signals to new generators:

- The current arrangements provide locational signals *implicitly* through the operation of the RIT-T, which involves consideration by TNSPs of the most net beneficial ways of meeting demand-side reliability standards.
- The OFA proposal provides locational signals *explicitly* through access pricing. However, these prices are themselves derived from TNSPs' assumptions about the future costs and profitability of generation investment in different locations.

The key question is whether the OFA proposal puts more or less weight on TNSPs' prior views of future generation investment patterns than the existing arrangements. In our view, the OFA proposal puts more weight on TNSPs' views than the existing arrangements because:

- Under the existing arrangements, TNSPs are principally and unavoidably required to forecast what generation may need to be developed to meet network reliability standards.
- Under the OFA proposal, TNSPs are required to forecast *all* generation investment (reliability-driven and non-reliability-driven) and the extent to which generation proponents are likely to make firm access applications.

The following sub-sections examine this issue in the context of a 'one-shot' single investment case as well as a multi-investment case.

14 Technical Report, pp.42-43, including Figure 6.3.

2.3.1 One-shot single investment case

In the most straightforward of cases, the current arrangements and the OFA proposal provide effectively the same locational signals.

Consider the original example in the above section (as set out in Table 1 – where the remote generation option is most efficient). In this example, the investor is making a one-off investment and choosing between a local generation option and a remote generation option that requires a network augmentation. For present purposes, assume that no other generation or transmission investment will occur in the future.

In these circumstances:

- Under the **current arrangements**, the investor would develop the remote generation option, knowing that the transmission augmentation to the remote location would satisfy the RIT-T and proceed.
- Under the **OFA proposal**, the TNSP would set a price of $90 million for firm access at the remote location. As the combined cost of remote generation and the firm access charge was below the cost of the local generation option, the investor would proceed with developing the remote option.

In this simple case, the effect of the implicit locational signals provided by the RIT-T would yield the same investment outcome as the explicit locational signals provided under the OFA proposal. In both cases, the investor would develop the remote generation option and the transmission augmentation would proceed.

2.3.2 Multi-investment case

Differences between the signals provided by the existing arrangements and the OFA proposal could arise in more complicated cases when TNSPs' longer-term views of generation developments become relevant.

Consider an example with the following assumptions:

- Investors face the same immediate choice between local and remote generation as in the revised example above (as set out in Table 2 – where the local option is more efficient) but
- In addition, the TNSP considers that due to rising fuel costs at the local location, future generation investment – and hence future demand for firm access – is more likely to arise at the remote location than the local location in the longer term

In these circumstances:

- Under the **current arrangements**, the implicit locational signals are similar to those in the revised example above because the TNSP's views of future generation firm access applications beyond those supporting the immediate investment are not relevant to whether the reliability augmentation ought to proceed – therefore:

- the local generation investment proceeds in the immediate term
- transmission and generation investment at the remote location may or may not occur in the future depending on whether new generator connection applications emerge at that location
- either way, this will feed into a *future* RIT-T analysis of the transmission investment

- Under the **OFA proposal**:
  - the TNSP sets a firm access price at the remote location based on its view that augmentation to the remote location is likely in future in response to the large number of firm access requests the TNSP expects to receive
  - due to economies of scale in transmission investment, the firm access price at the remote location is lower (in $/MW) than the price charged under the one-shot single-investment case – for example, the firm access price at the remote location may be $70 million instead of $90 million
  - as a result, the original investor finds it worthwhile to invest in remote generation instead of local generation because the combined cost of remote investment is $190 million (being $120 million plus $70 million firm access charge) which is less than the $200 million cost of the local option

Therefore, the OFA proposal could lead to different investment outcomes than under the current arrangements *for no other reason than the TNSP's view of likely patterns of future generation investment*. Accordingly, the notion that the OFA proposal promotes 'market-led' investment decision-making is false. The OFA proposal simply promotes generation investment in line with the TNSP's prior and untested expectations.

It is important to note that the possibility of erroneous access prices (due to incorrect assumptions or forecasts made by TNSPs) leading to sub-optimal investment outcomes would represent a welfare reduction relative to the status quo. That is, there is a risk that incorrect access prices may not simply fail to achieve the theoretically 'optimal' outcome, but may in fact lead to an outcome that is considerably worse than that what would have eventuated under the status quo arrangements.

2.3.3 Informational integrity of both approaches

As noted above, to the extent that TNSPs set firm access prices on the basis of the same information they use when making reliability transmission investment decisions, the OFA proposal should lead to similar investment outcomes as under the existing arrangements. The issue as demonstrated in the multi-investment case example is that the OFA proposal could lead to different investment signals and outcomes where TNSPs' views of future generation investment patterns and firm access applications affect the prices they charge for firm access.

The divergence in the locational signals provided under the existing arrangements and the OFA proposal is driven by the need for TNSPs to make judgements about future generation investment in the OFA model. These judgements go beyond the judgements TNSPs need to make under the existing reliability-focussed arrangements. Whether this is a good or bad thing from an economic efficiency perspective depends in part on whether one believes that TNSPs are likely to have better information about future generation and transmission costs than generation investors.

Under the existing arrangements, all significant transmission investments must be assessed under the RIT-T on an individual piecemeal basis immediately prior to the investment proceeding. This process has several advantages:

- The RIT-T involves an extensive public consultation process. To the extent that the TNSP's analysis is based on flawed assumptions, stakeholders have an opportunity to comment on and correct those assumptions.
- The proximity of the assessment to the timing of the transmission investment means that investments satisfying the RIT-T should reflect the best currently available information about future load growth and generation and transmission costs at different locations. As a result, the locational signals provided to investors through the approval or non-approval of transmission investments should be the *most accurate and transparent signals that can be provided* within the framework of a monopoly transmission planning regime.
- The incremental nature of the way in which the RIT-T is applied to transmission investments provides scope for generation investors to second-guess future transmission investment decisions. When making very long-lived investment decisions, investors have incentives to predict the outcomes of future RIT-Ts long into the future to the extent future transmission investments will affect their viability. Therefore, even if transmission investment is not required anywhere for some time, a generation investor presently has incentives to consider where and how the RIT-T would apply over the lifetime of its investment. If a generation investor believes that the TNSP's assumptions about future transmission investment in its Annual Planning Reports are wrong – because, for example, the investor believes the TNSP has a mistaken view of future generation investment patterns – the investor is free to invest on the basis that the TNSP will eventually 'see the light' and change its transmission investment plans over time. Hence, the existing approach encompasses a process of investors continually seeking to

guess how the TNSP will apply the RIT-T now and in the future as more information becomes available.

By contrast, the pricing of firm access under the OFA proposal reflects the crystallisation of the TNSP's present views on patterns of generation investment well into the future. Once settled, firm access prices cannot be revised in light of new or changed information. This serves to effectively 'lock in' the implications of errors in the TNSP's assumptions. Further, there does not appear to be a significant role for stakeholders to comment on or influence the assumptions on which prices are based. This means that the price signals under the OFA proposal may not reflect the best information available to the marketplace.

Pricing under the OFA proposal also gives rise to incentives and opportunities for TNSPs to misprice firm access to enhance their own financial positions. This issue is discussed in section 3.2 along with other governance concerns.

3 Governance and costs of OFA implementation

The governance and costs of OFA implementation are relevant to the evaluation of the proposal in two key ways.

First, the Second Interim Report notes that in undertaking the TFR, the AEMC is obliged to have regard to COAG principles that:

- Accountability for jurisdictional investment operation and performance will remain with TNSPs
- Where possible, the new regime must be at a minimum be no slower than the present time taken to gain regulatory approval for transmission investment and
- The new regime must not reduce or adversely impact on the ability for urgent and unforeseen transmission investment to take place[15]

Second, part of the National Electricity Objective involves the promotion of 'good regulatory practice'. This means that any assessment of changes to the Rules should take account of:

- the value of regulatory stability and predictability of the market design and regulatory regime
- the importance of transparency in market and regulatory processes
- the need for alignment of decision-making responsibility with financial and legal accountability
- the magnitude of the costs of implementation

The OFA proposal gives rise to a number of interdependent concerns about appropriate governance and good regulatory practice. These concerns arise in relation to:

- setting NOCs and FAS scaling factors (section 3.1)
- derivation of access prices and payment profiles (section 3.2)
- the arrangements allowing trading of firm access rights (section 3.3)
- role and implications of the RIT-T (section 3.4)
- the TNSP's access rights queuing policy (section 3.5)

15 Second Interim Report, p.v.

3.1 Setting NOCs and the related FASs

A key prerequisite for the OFA proposal to provide its claimed benefits is appropriate setting of normal operating condition (NOC) tiers for each flowgate and the corresponding firm access standards (FASs) for each tier. In particular, someone would need to determine:

- under what conditions would different NOC and abnormal operating condition (AOC) tiers apply to *each and every transmission flowgate* in the NEM
- what should be the NEM-wide FAS scaling factor applicable under each NOC and AOC tier

The Technical Report notes that the setting of NOCs and FAS scaling would be undertaken during implementation and would involve TNSPs, AEMO and generators.[16] There is no mention of a role for the AER.

From the outset of implementation, TNSPs would have strong incentives to minimise their financial exposures to reduced levels of transmission availability such as by:

- Defining NOC tiers very conservatively, so that the higher tiers (eg NOC1, NOC2) only apply a relatively small proportion of the time whereas the lower tiers (eg NOC3, NOC4) apply a relatively large proportion of the time
- Defining AOC conditions very loosely, so it applies a relatively large proportion of the time
- Minimising the FAS scaling factor (the percentage of the nominal entitlement provided to holders of firm access rights) at each NOC and AOC tier

While AEMO and generators would have a role in the implementation process, it is difficult to see how they would have the information and resources to effectively challenge a TNSP's view of the appropriate definitions of NOC tiers and the attendant levels of FAS scaling factors for each NOC tier.

Neither AEMO nor generators would have the ability to force a TNSP to abide by a FAS table that reflected a reasonable – let alone challenging – relationship between underlying network conditions and financial accountability for transmission availability and firm access. Any exposure of TNSPs to financial risks in the provision of prescribed services (such as firm access) would need to involve the AER in addition to TNSPs, AEMO and generators. All parties would need to retain their own electricity transmission engineers to support their contentions that NOC tiers were defined too narrowly/broadly and that firm access standards were too high/low in respect of each NOC tier for each transmission flowgate in each TNSP's network.

16 Second Interim Report, p.27; Technical Report, p.31.

Effectively, the OFA proposal would put the AER in a position where it would have to arbitrate on the design of a performance incentive regime that:

- was many times more complicated than the current market performance incentive regimes applicable to TNSPs in the NEM and
- applied in respect of *each and every transmission flowgate* in the NEM

This would be an extremely expensive and time-consuming process for all parties. Until this process was completed, no generator would be willing to apply and pay for firm access rights. Arguably, generators would mainly need to be concerned with NOC classifications and FAS scaling levels in the immediate period leading-up to a negotiation of firm access rights. After their rights were agreed for a period, they could avoid engaging in debates about firm access. However, the AER would face on ongoing need to seek advice from network engineers in relation to these issues. The total costs are likely to run into the tens of millions of dollars across the NEM.

3.2 Derivation of access prices and payment profiles

3.2.1 Complexity of OFA pricing

The derivation of access prices and payment profiles under the OFA proposal is an abstract and complex exercise, which raises concerns about its transparency. The complexity applies to:

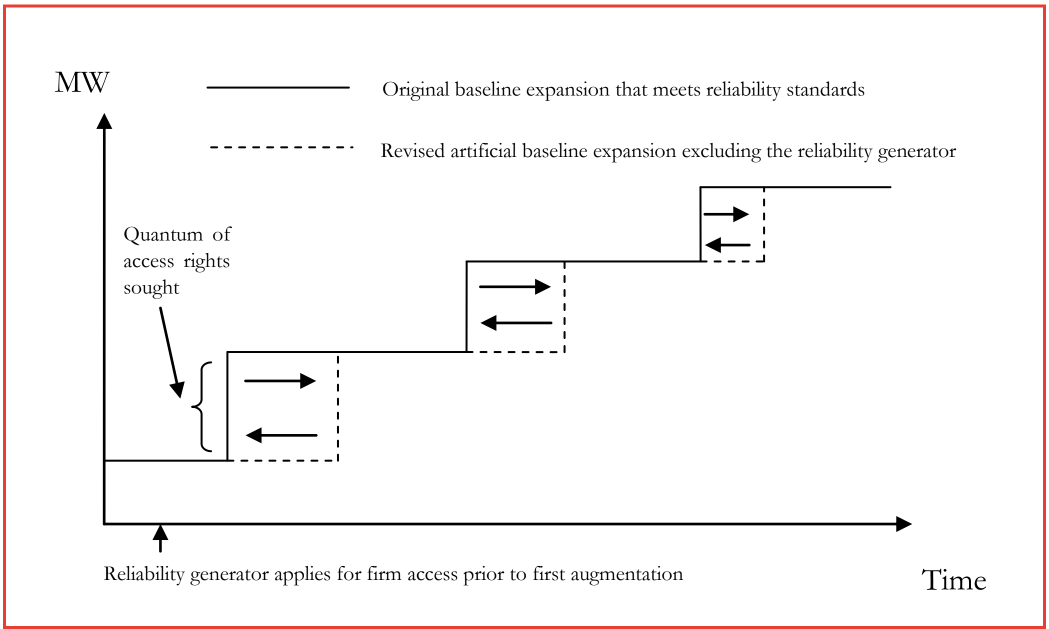
- Access pricing in relation to reliability transmission investments
- Access pricing in relation to non-reliability transmission investments
- Access pricing in relation to existing generators

Access pricing in relation to reliability investments

One implication of the proposed broad approach to pricing firm access rights is that a request for firm access rights consistent with the assumed development of the transmission network in the baseline expansion plan ought to attract a nil price. For example, assume that a TNSP expected to augment a transmission line to location X in 2015 to enable load growth in location Y to be met and reliability standards to be satisfied. Then assume that a new generator intending to locate at X made an application for firm access rights commencing in 2015 equivalent to the capacity of the augmentation. As the augmentation would be undertaken to meet reliability standards irrespective of the firm access application, satisfying the firm access request could not be said to impose additional costs on the TNSP. No transmission investment would need to be brought forward and transmission charges to customers would not be any higher than otherwise. The Technical Report acknowledges that the calculated access price to such a 'reliability generator' would be zero because the generator would appear equally in the baseline studies and the adjusted studies.[17] To avoid what it describes as an anomalous outcome, the Technical Report proposes that any generator seeking access rights be artificially removed from the baseline expansion plan. This would ensure that there was a NPV cost difference between the baseline expansion plan and the modified expansion plan. Taking the above example, the TNSP would need to recalibrate the date of its intended reliability augmentation from 2015 to some later date to reflect the absence of the generator seeking access. This would be a highly abstract exercise because it would involve assuming that the reliability standards driving the need for the investment were relaxed by exactly the amount that would be satisfied by the generator seeking access. For example, if the so-called reliability generator seeking firm access was expected to provide 400 MW of power at peak demand times, the hypothetical baseline expansion plan to price firm access to that generator would need to assume that demand was 400 MW lower than it was in reality expected to be.

Figure 4 below highlights the situation where a generator consistent with meeting reliability standards seeks firm access prior to the first in a series of forecast augmentations going ahead.

Figure 4: Pricing firm access pricing to a reliability generator



Source: Frontier Economics

[17] Technical Report, section 6.2.3, p.40.

This figure shows that to price firm access rights to this generator, the TNSP would need to:

- First, develop a baseline expansion plan for the relevant branch element(s) that ensure reliability standards are satisfied
- Second, calculate the NPV of forecast transmission investment on the relevant branch element(s) *assuming away* the expected flow on the transmission element(s) attributable to the generator's firm access rights
- Third, calculate the NPV of transmission investment on the relevant branch element(s) *assuming back* the expected flow on the element(s) due to the generator's firm access rights
- Fourth, compare the NPV costs to determine the access price payable by the generator

This process would appear to open up considerable opportunities for TNSPs to overcharge reliability generators for firm access rights. For example, TNSPs could inform the generator that removing it from the baseline would allow deferral of a transmission investment for a long period, thereby resulting in a high access price.

Non-reliability investment

More generally, the Technical Report proposes that to the extent that a TNSP has incorporated some probability of a firm access application from any future generator (not necessarily a reliability generator) in its baseline expansion plan, the TNSP would be required to remove the expected quantity of firm access from the baseline expansion plan.[18] For example, if the TNSP has assumed that there is a 30% probability of a particular 100 MW generator making an access request and proceeding to completion, and that generator actually does proceed to completion, the flow in the baseline expansion plan used to calculate that generator's access charge must be reduced by 30 MW (being 30% of 100 MW). In that way, the firm access charge for any generator would reflect the full impact of the output equivalent to the rights sought by that generator on transmission costs.

The need to artificially remove some or all of a firm access applicant's capacity from the baseline expansion plan complicates the approach to access pricing, undermining its transparency and expanding the scope for generators to be overcharged.

18 Technical Report, section 6.3.5, p.45.

Access pricing to existing generators

The OFA proposal incorporates transitional firm access rights to existing generators based on their "historical levels of effective access".[19] The duration and extent of these transitional rights is undetermined, but the expectation is that the rights would be for less than the entire capacity and the remaining life of existing plant.[20] This means that existing generators seeking to maintain firm access would eventually need to pay for firm access rights.

The determination of access prices to existing generators raises similar conceptual and practical difficulties as pricing access to generators consistent with the satisfaction of reliability standards. A request for firm access by an existing generator following the expiry of its transitional rights should, on its face, attract a nil price. Such a request could not be said to cause the TNSP to bring forward any investment or incur any additional costs. To prevent this outcome, the price of access to existing transmission capacity would be based on expected demand for firm access post the expiration of transitional rights. Therefore, the extent to which TNSPs expect future firm access demand would drive the price of future firm access, even to existing generators.

This means that for a given transmission branch element originally utilised by an existing generator:

- If the TNSP expected that future demand for firm access on that element would be relatively high – the price of maintaining firm access to existing generators would be relatively high
- If the TNSP expected that future demand for firm access on that element would be relatively low – the price of maintaining firm access to existing generators would be low

As with the pricing of access to other generators, access prices to existing generators would largely be a function of the TNSP's views of future generation development along each branch element. These views are likely to be more and more speculative the further in advance TNSPs are required to form their views in response to access requests. In this context, it would be quite logical for an existing generator granted, say, a 10 year transitional access right to immediately seek to extend the right for an additional 10 year period. To price this right *today*, the TNSP would need to forecast the level of generic firm access requests it expects to receive in relation to that branch element for the period 10 to twenty years-plus in the future. It is difficult to envisage how such a process could yield anything other than an arbitrary access price.

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19 Second Interim Report, pp.23, 38-39.

20 Technical Report, pp.65-66, including Figure 9.2.

3.2.2 Pricing institution

The previous section assumed that the TNSP would be responsible for determining firm access prices on its network. However, the OFA proposal formally leaves open the identity of the institution that determines access pricing and annual payment profiles. The Technical Report notes that there are good reasons both for pricing to be undertaken by a NEM-wide institution as well as for it to be agreed between the applicant and its local TNSP.

The key argument against allowing access pricing to be determined by the relevant TNSP is it would have incentives to overcharge an access-seeking generator, such as by:

- For new generators – exaggerating the extent to which the access application would bring forward the need for transmission investment
- For existing generators – exaggerating the number, size and likelihood of other access applications in the same location in order to increase the default estimated price

While overcharging would not increase a TNSP's regulated revenues, it would minimise the need for the TNSP to recover revenues from politically-sensitive end-use consumers. TNSPs may prefer to manage their regulatory risks in this manner.

As with the setting of NOC tiers, an access applicant would have an extremely limited ability to second-guess a TNSP's estimate of the impact of the application on the timing and cost of network investment. This would particularly be the case where the generator applied for access in relation to a reliability-driven transmission augmentation. The timing of the investment would not itself change, but the number of years' carrying cost the applicant was charged would be determined by the TNSP based on the process described above of artificially removing and reinstating the generator in the baseline expansion plan. Therefore, even if default pricing was left to the TNSP in the first instance, good regulatory practice would once again require the AER to review the TNSP's prices. The ability of the AER to meaningfully audit firm access prices would be limited given the sheer number of assumptions and the level of technical detail involved in calculating an access price. This suggests an additional need for the AER to maintain an ongoing engagement of transmission network engineers.

Further, if the TNSP was responsible for setting the annual payment profile, it would have incentives to front-end load the payment profile in order to maximise its incremental access revenue within a regulatory control period. As noted in the Technical Report, any divergences between access payments and investment carrying costs beyond the first control period would not affect the TNSP. To the extent the TNSP engaged in front-end loading of payments, this would be at the expense of end-use TUoS-paying consumers. This again suggests the need for AER oversight of the setting of access payments.

If access pricing and payment profiles were determined by a centralised body such as the National Transmission Planner, different problems would arise. The Technical Report notes that this could make the process much less effective and timely. This point should not be underestimated, because each prospective new generator may seek indicative access prices at several different locations. This would require a central body to have information about all prospective transmission investments across the NEM for the next ten or more years as well as the sensitivity of these investments to changes in firm generation quantities and locations. Such a central body would face little accountability for making incorrect forecasts, which would compromise good regulatory practice.

3.3 Trading of firm access rights

The OFA proposal incorporates scope for the trading of firm access rights. A number of requirements would need to be met for trade to occur to ensure that the trade did not place additional demands on flowgate capacity to those that existing before the trade.[21]

The key governance concern with trading is that under the proposal, TNSPs are required to examine and approve trades of firm access rights. This may create incentives for TNSPs to disallow trades on spurious grounds in the hope or expectation that the generator seeking to acquire rights would then approach the TNSP to augment the network to achieve the same outcome. If successful, this would boost the TNSP's regulated asset base and allowable revenues from the provision of prescribed transmission services.

3.4 Role and implications of the RIT-T

The role of the RIT-T under the OFA proposal is unclear.

Under the current regulatory arrangements, TNSPs have to apply the RIT-T before undertaking a transmission augmentation. The RIT-T process examines whether:

- the option being undertaken is preferable to credible alternatives
- the timing of the investment is preferable to alternative timings
- the investment is costed in an efficient (cost minimising) manner

The RIT-T is a check on unnecessary or inappropriate investment.

Under the proposed arrangements, AEMC staff suggested at the OFA public forum that the AER would retain a role in scrutinising transmission investment using the RIT-T or a similar tool. However, the role of the AER would be

21 Technical Report, p.53.

limited to ensuring the technical option decided on by the TNSP was the cheapest way of providing a given quantity of network capacity at the time of the access application, as opposed to assessing whether the investment was appropriate in terms of size/scale, alternative options and timings.

If this understanding is correct, it suggests that the role of the RIT-T would be greatly weakened under the OFA model. A TNSP could propose an over-specified option and proceed with that option so long as it was efficiently costed (eg the work was technically well-specified and competitively tendered). The costs of any excessive or inappropriate investment would be borne by the access seeker and end-use customers as well as proponents of other options that could be more easily ignored under the OFA proposal.

Alternatively, the intention may be that the RIT-T would have a similar role as at present for reliability investments, except that market benefits would be ignored. That is, the AER would use the RIT-T process to ensure the option put forward was the most appropriate option and had the most appropriate timing to meet reliability standards and expected FASs, as well as ensure that the project was the cheapest option available given those criteria.

If this were the case, we consider that the timeframe for new generation investment could be substantially extended for a number of reasons. First, TNSPs are likely to be inhibited in making firm access offers to generators prior to a RIT-T assessment if new transmission investment is required to meet the requested FAS. In order to make sure they could satisfy the requested FAS, TNSPs would have incentives to postpone making offers until they had successfully undertaken a RIT-T analysis for any relevant investment(s). Currently the RIT-T process for a single, well-defined transmission upgrade takes on the order of 1-2 years to complete. It is hard to see how TNSP's could manage to run multiple and virtually continuous RIT-Ts in response to firm access requests in anything like a timely fashion. Therefore, the ability to respond in a timely fashion to access requests is likely to be severely undermined by the inherent incentives that TNSPs face in acquiring RIT-T 'sign-off' prior to undertaking investments to meet the requested FAS.

Of course, after a RIT-T is successfully undertaken, access seekers would have strong incentives to postpone their applications until after the transmission investment is commissioned or otherwise considered 'sunk'. At this time, the LRIC of access would presumably be relatively low. This means that upon receiving a provisional access price, the access seeker could decide not to proceed with the application. This could mean that TNSPs spent much time undertaking numerous costly and time-consuming RIT-Ts to manage their own risks.

The Technical Report states that where expansion is necessary prior to access commencement, TNSPs would be permitted to reasonably delay access commencement to give time for such expansion. We consider that this is likely to be the case on virtually every occasion.

3.5 Queuing policy

The approach to managing firm access application queues is a crucial element of the OFA proposal. This is because an applicant's position in the queue could be a major factor in the provisional and final prices they are asked to pay for firm access.

For example, where spare capacity on a branch element was relatively high, LRIC prices would be relatively low. As spare capacity was absorbed, LRIC prices would rise. This means that where spare capacity exists or immediately after a transmission branch element is augmented, generators located or intending to locate in a particular area would have strong incentives to make applications prior to other generators make applications. The result could be either of the following:

- An arbitrary price outcome for each access-seeker based on potentially how many days, hours or even minutes they made a specific provisional access request to the TNSP ahead of other applicants. Such an approach would potentially give a strong benefit to incumbents, who may be able to obtain firm access relatively cheaply by 'getting in first' with their applications.
- An alternatively arbitrary process, whereby the TNSP or NTP bases access prices on provisional access requests received over a given period of time, such as through an 'open season'-type process or by attributing high probabilities to other applications in the price determination process. In this case, the precise order of an application within a queue would not matter as much, as applicants would be offered a price closer to the LRMC of network expansion at the relevant location. However, if this approach was adopted, the identity and firm access requirements of other applicants might need to be disclosed to enable applicants to properly assess the assumptions behind the prices they were offered.

The Technical Report does not explain how the queues arising in the access procurement process would be managed other than that they will be dealt with on a first-come-first-served basis.

4 Issues the OFA proposal fails to overcome

The OFA proposal seeks to address a number of purported flaws in the current NEM design. These include:

- Lack of firm financial access for generators to support forward contracting
- 'Disorderly bidding' and the effect this can have on economic efficiency
- Lack of firm inter-regional financial rights
- Lack of locational signals for new generators

The last of the issues was examined in detail in section 2.

This section discusses how the OFA proposal fails to overcome the first three of the above issues:

- Section 4.1 considers how the OFA proposal fails to provide firm access generally
- Section 4.2 considers how the OFA proposal fails to address disorderly bidding and
- Section 4.3 discusses the shortcomings of the OFA proposal in relation to inter-regional rights

4.1 Firm access and contracting

4.1.1 Contracting levels under OFA proposal

One of the key drivers and claimed benefits of the OFA proposal is an increase in financial certainty for generators. According to the Second Interim Report, increased financial certainty would flow through into lower financing costs for investors, making investment more attractive and lowering prices to consumers.[22] The report goes on to suggest that the OFA proposal would lead to a "higher expected level of hedging... as compared to under the [Non-Firm Access] model".[23] The Technical Report also states that other things being equal, "there will typically be increased forward contracting under the OFA model".[24] At the same time, both the Second Interim Report and the Technical Report acknowledge that non-firm generators would face increased basis risk under the

22 Second Interim Report, p.47.

23 Second Interim Report, p.48.

24 Technical Report, p.85.

OFA proposal than under the status quo.[25] This is because they may be forced to compensate firm generators at times of flowgate constraints.

Under the existing dispatch and settlement arrangements, generators can contract in the knowledge that if constrained-off, they will earn the RRP on their dispatched quantity. Assuming constrained-off generators bid at the market floor price, their dispatched quantity will be a function of:

- the size of their offered capacity relative to the offered capacity of other generators affected by the constraint
- the relative size of their coefficient in the relevant constraint equation(s) and
- the flow limit of the relevant constraint(s)

Contrary to the opinion expressed in the Second Interim Report,[26] generators have a reasonable idea of these variables in advance of a constraint binding. This assists generators in their current contracting decisions.

Consider the following example:

- Three generators are located behind a transmission constraint with a capacity of 1000 MW and each has an equivalent constraint coefficient:
  - Generator 1 (G1) has a capacity of 600 MW
  - Generator 2 (G2) has a capacity of 400 MW
  - Generator 3 (G3) has a capacity of 200 MW
- If the RRP is high and all generators wish to be fully dispatched, all will bid -$1000/MWh
- Assuming all generators are fully available:
  - G1 can expect to be dispatched to approximately 500 MW (being 600/(600+400+200) * 1000)
  - G2 can expect to be dispatched to approximately 333 MW (being 400/(600+400+200) * 1000)
  - G3 can expect to be dispatched to approximately 167 MW (being 200/(600+400+200) * 1000)
- That is, all generators will impliedly receive an access right equivalent to about 10/12ths of their capacity
- If the transmission line is subject to an outage, the proportion will be lower – but that would also occur under the OFA proposal

25 Second Interim Report, p.48; Technical Report, pp.12-13 (including footnote 15).

26 Second Interim Report, pp.47-48.

Therefore, it is wrong to suggest – as the AEMC does[27] – that just because congestion is volatile and unpredictable, generators' current willingness to contract is significantly below what it would be under the OFA proposal. Generators' knowledge of their local network topology and generation conditions can and does feed into their contracting decisions. Further, under the current arrangements, because of the influence of other generators' available capacities in determining the dispatch and access of a particular generator, generators often enjoy an automatic increase in their implicit access rights precisely at times that other generators are unavailable and when spot prices are high as a result.

Consequently, whether the level of forward contracting would increase under the OFA proposal is highly ambiguous. Firm generators may contract more than they do at present; but non-firm generators are likely to contract less. In fact, unless non-firm generators are given full information about the quantity and timeframe of firm access rights acquired by other generators, risk-averse non-firm generators may curb their contracting by more than necessary to fund the payment of compensation to firm generators. Therefore, for a given amount of transmission capacity, it is far from obvious that the overall level of contracting would increase under the OFA proposal.

To demonstrate real inefficiency in the current arrangements, it would be necessary to show that the existing capacity-based allocation of dispatch at the RRP is materially less efficient than would occur under the OFA model. The OFA model may, if properly and unbiasedly implemented, lead to firm access being allocated to generators that value it most highly. Other things being equal, the OFA proposal could lead to settlement at the RRP being acquired by more risk-averse generators, leaving less risk-averse generators with a lower level of settlement at the RRP (with their remaining settlement at their local nodal price). This reallocation of RRP access may result in contracting decisions that lead to a theoretical efficiency gain in the long run. However, the magnitude of this gain is difficult to measure and it may be immaterial.

4.1.2 'Firmness' under OFA proposal

As noted above, access rights under the OFA proposal would not be fully firm under all circumstances. The FAS would be defined by different specified tiers of NOCs and a FAS scaling factor for each tier. When system conditions fell short of 'system normal' (NOC1), firm access rights may be scaled down to avoid subjecting TNSPs to financial risk they cannot manage. This means that generators with a particular volume of firm access rights may not be 'made whole' with respect to the RRP in relation to that volume of rights.

[27] Second Interim Report, pp.47-48.

Generators that have procured a level of access in excess of their availability would be regarded as 'super-firm'. Super-firm generators' access rights would also begin to be scaled down under deviations from system normal. However, this may not immediately affect super-firm generators if their scaled access levels were still above or equal to their availabilities.

The Second Interim Report notes that the setting of NOCs and FAS scaling would be undertaken during implementation and would involve TNSPs, AEMO and generators. This potentially raises importance governance issues, as discussed in section 3.1.

Ultimately, under the OFA proposal, generators would not be able to rely on financially firm access under non-system normal conditions. Yet these are precisely the conditions when generators are most likely to face dispatch risk and the financial risk of unfunded difference payments.

4.2 Disorderly bidding and inefficiency of market dispatch

One of the claimed benefits of the OFA proposal in Box 4.1 is more efficient dispatch of generators, due to reduced incentives for 'disorderly bidding'. Section 4.4.1 of the Second Interim Report notes that:

> Currently...[g]enerators located in a congested part of the network have an incentive to offer electricity at a price less than their short run marginal cost – a process known as disorderly bidding. This may result in productive inefficiency, with more expensive generation (in terms of operating costs) dispatched ahead of cheaper generation.[28]

Further:

> The OFA model would reduce the incentives for disorderly bidding by decoupling access to the regional reference prices from an individual generator's dispatch level, and should therefore enhance productive efficiency.[29]

The Technical Report goes as far as suggesting that the OFA proposal would "solve the problem of disorderly bidding", where disorderly bidding is defined as bidding down to -$1,000/MWh under constrained-off conditions.[30]

However, as explained in our report for the NGF in response to the AEMC's First Interim Report,[31] options based on generator nodal pricing that provide

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28 Second Interim Report, p.52.

29 Second Interim Report, p.52.

30 Technical Report, p.12.

31 Frontier Economics, *Transmission Frameworks Review – 1st Interim Report, A Report Prepared for the National Generators Forum*, April 2012, p.31.

generators with firm access rights may themselves promote non-cost reflective bidding and dispatch inefficiency. Such options can:

- Give generators with a degree of transient market power incentives to withhold capacity to create 'headroom' on transmission lines between their location and the regional reference node
- Give generators with financial transmission rights incentives to bid below their short run marginal cost (SRMC) in order to receive larger compensation than the operating loss on dispatched output

The Second Interim Report acknowledges these incentives in section 4.4.3, noting that the OFA proposal could create a strategic 'tug-of-war' that would tend to drive the dispatch of firm generators towards their firm access level and the dispatch of non-firm generators towards whatever transmission capacity is left.[32]

However, the Second Interim Report does not acknowledge that due to these incentives:

- The effect of the OFA proposal on non-cost-reflective bidding is ambiguous
- The effect of the OFA proposal on dispatch efficiency is ambiguous

Further, the Second Interim Report does not acknowledge that:

- The OFA proposal does nothing to deter disorderly bidding by constrained-on generators and
- The resource costs of disorderly bidding in the NEM are relatively small

These issues are discussed below.

4.2.1 Effect on non-cost-reflective bidding is ambiguous

The Second Interim Report notes that the OFA proposal may create perverse bidding incentives, including firm generators bidding below SRMC to drive down local nodal prices.[33] In other words, the OFA proposal may reduce existing forms of disorderly bidding under some conditions but increase non-cost-reflective bidding under other conditions. The Second Interim Report does not provide any qualitative or quantitative evidence to suggest that non-cost-reflective bidding would necessarily reduce under the OFA proposal compared to the status quo arrangements.

Consider the following example adapted from the First Interim Report.

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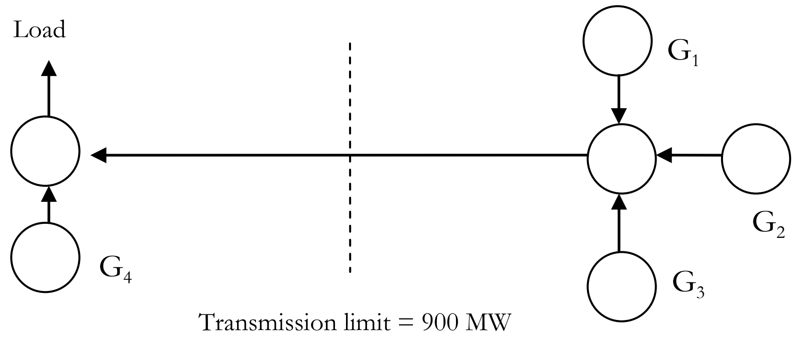
32 Second Interim Report, pp.53-54.

33 Second Interim Report, pp.53-54.

Figure 5: Non-cost-reflective bidding example



Source: Frontier Economics

Assume that:

- Load is 1000 MW
- G1, G2 and G3 each have capacities of 400 MW
- G1's SRMC is $20/MWh
- G2's SRMC is $40/MWh
- G3's SRMC is $60/MWh
- G4's SRMC is $50/MWh
- G3 has firm access rights of 200 MW

Under the current arrangements, G3 would not have incentives to bid disorderly and would not be dispatched because the RRP of $50/MWh is less than G3's SRMC of $60/MWh. Rather, G1 and G2 would be fully dispatched, G4 would dispatched to 200 MW and the transmission constraint would not bind. G3's profits would be zero.

However, under the OFA proposal, G3 would be entitled to significant compensation for not being dispatched if the line constrained. This means G3 would have incentives to bid just over 100 MW below G2's SRMC ($40/MWh) in order to force the constraint to bind. The RRP would remain $50/MWh, but G3 would earn positive profits overall – G3 would earn:

Revenue of:

$50/MWh * 100 MW

+ ($50/MWh - $40/MWh) * 200 MW

= $7,000/hour

Less operating costs of:

$60/MWh * 100 MW

= $6,000/hour

Equals operating profit of:

= $1,000/hour

4.2.2 Effect on dispatch efficiency is ambiguous

It is unclear whether the changes to bidding incentives brought about under the OFA proposal would necessarily improve the economic efficiency of dispatch. In the above example, note that dispatch resource costs under the current arrangements would be minimised at $34,000 (being 400 * 20 + 400 * 40 + 200 x 50). However, under the OFA proposal, non-cost-reflective bidding would drive dispatch resource costs up to $35,000 (being 400 * 20 + 400 * 40 + 100 * 50 + 100 * 60).

4.2.3 Disorderly bidding by constrained-on generators remains

Another point to note is that the OFA proposal does nothing to discourage disorderly bidding by constrained-on generators bidding towards the market price cap (or unavailable) to avoid being dispatched. This is because flowgate support generators continue to be paid the RRP even when their shadow nodal price is above the RRP.

4.2.4 Costs of disorderly bidding are small

As noted in our report on the First Interim Report, the costs of disorderly bidding in the NEM are relatively small. On behalf of the AEMC for the Congestion Management Review, we estimated that the total resource cost savings from eliminating all mis-pricing was about $8 million for the 2007/08 financial year, assuming generators do not respond to more localised prices by exercising transient market power.[34] Compared to a market turnover in that year of $11.1 billion,[35] this is a cost equivalent to just 0.07% of turnover.

4.3 Inter-regional transmission investment and FIRs

One of the purported shortcomings of the existing arrangements is the lack of firm inter-regional transmission rights. The current Inter-Regional Settlement

34 AEMC, *Congestion Management Review, Final Report*, June 2008, p.33.

35 AER, *State of the Energy Market 2008*, p.77.

Residue (IRSR) rights are not always firm for a number of reasons. One reason is that interconnector flows do not reach the notional capacity of directional interconnectors when inter-regional price differences arise. The OFA proposal seeks to address the issue of non-fully firm inter-regional transmission rights.

4.3.1 Outline of FIRs

The Second Interim Report and the Technical Report note that the existence of hybrid flowgates in the NEM means that the allocation of transmission rights to interconnectors is unavoidable.[36] Inter-regional network access in this context refers to a value of rentals arising from the price difference between the relevant RRPs. A FIR provides the holder of the rights the difference in RRPs multiplied by the relevant quantity of FIRs, adjusted for any scaling.

A key feature of the FIR component of the OFA proposal is that interconnector augmentation decisions would no longer be based on one or more TNSPs undertaking the RIT-T. Rather, a 'central agent' such as AEMO would run a procurement tender whereby it would accept bids for augmentation and the augmentation would proceed if the aggregate value of bids met or exceeded the cost of the augmentation.[37]

The Technical Report suggests that FIRs would be issued in two ways:

- Existing inter-regional capacity would be auctioned by AEMO in a similar manner as existing IRSRs are auctioned through Settlements Residue Auctions (SRAs)
- New inter-regional capacity would be issued to those market participants that agreed to fund the augmentation through a procurement tender[38]

Finally, the Technical Report notes that it is proposed that intra-regional generation will receive priority over inter-regional on congested flowgates during the period of transitional access.[39]

4.3.2 Issues and concerns

The FIR concept adds further complexities to the design and operation of the OFA proposal. Some of the issues and concerns arising from these complexities are outlined below.

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36 Second Interim Report, p.40; Technical Report, p.68.

37 Technical Report, pp.73-74.

38 Technical Report, p.72.

39 Technical Report, p.80.

Interaction between intra- and inter-regional access rights

The Technical Report contains limited explanation of how FIRs would interact with intra-regional firm access rights. The key point to come across is that hybrid flowgate capacity would be allocated primarily to intra-regional generators, on the basis that they currently receive this capacity by bidding their capacity at -$1,000/MWh. If hybrid capacity were allocated in this way, then the existing inter-regional capacity available to be auctioned for certain interconnectors could be extremely limited.

Efficiency of inter-connector augmentation

Despite the comment made in section 10.2.5.2 of the Technical Report, there is no guarantee that requiring inter-regional augmentation decisions to be based on a bidding process would lead to efficient augmentation.

One reason why a funded augmentation may not be efficient is that the gross benefits of an augmentation typically exceed the net benefits. The difference between the gross and net benefits represents the *wealth transfer* impact of an augmentation. An important implication of these wealth transfers is that just because a group of participants finds it worthwhile to fund an augmentation in exchange for FIRs does not imply that the augmentation provides a *net market benefit* as that term is defined in the RIT-T.

For example, it may be that the benefit of an interconnector augmentation to generators in an exporting region and consumers in the importing region is:

- <u>greater</u> than the <u>cost</u> of the augmentation but
- <u>less</u> than the <u>cost</u> of the augmentation <u>plus the disbenefit</u> of the augmentation to generators in the importing region and consumers in the exporting region

In other words, it may be profitable for a subset of participants to fund an interconnector augmentation even though the investment has a negative effect on overall market welfare. This is because part of the benefits received by the funding participants comes at the expense of other (non-funding) participants – the augmentation secures a wealth transfer in favour of the funding participants.

Alternatively, potential beneficiaries of interconnector investment may find it worthwhile to not pay and 'free-ride' on the decision of others to fund an augmentation. This could lead to sub-optimal levels of interconnector augmentation. The Technical Report notes the scope for free-riding, but suggests that the benefits from inter-regional augmentation will come primarily from possession of FIRs. The implication appears to be that free-riding would not occur.

However, it is far from obvious or likely that free-rising would not occur because non-payers cannot be excluded from at least some of the benefits of an augmentation – for example:

- Consumers in an importing region benefit from greater import capacity and lower average wholesale prices than otherwise
- Generators in an exporting region benefit from greater export capacity and higher average wholesale prices than otherwise

TNSP bidding for FIRs

The Second Interim Report suggests that TNSPs may bid for FIRs if they can demonstrate that FIRs would be a cheaper way of satisfying demand-side reliability standards or firm access rights more generally.[40] To justify bidding for FIRs, TNSPs would need to justify their bids through a RIT-T or similar cost-benefit analysis.

This is unlikely to be a practicable process for a number of reasons.

First, undertaking a RIT-T takes a significant amount of time and consultation. It is difficult to see how this could be completed prior to the central agent holding a bidding process for new FIRs.

Second, to justify bidding for FIRs under a RIT-T, the TNSP would need to specify an appropriate 'base case' state of the world in which it did not bid for FIRs. It may be that the interconnector augmentation would at least partially proceed even without its bid. If this were the case, the TNSP may not be able to justify bidding for the FIRs. In effect, the TNSP's ability to make a bid to the central agent could become a circular and indeterminate problem in that:

- The TNSP would need to await the outcome of the FIR bidding process to find out whether the augmentation would be funded in the absence of its bid, so as to determine whether its bid was necessary to enable the augmentation to proceed and
- The TNSP would only be able to procure FIRs by submitting bids to the central agent during the procurement tender

It is difficult to see how this conundrum could be resolved. TNSPs may respond by not bidding for FIRs at all, with the result that transmission investment outcomes would be sub-optimal. Alternatively, the TNSP could simply assume that its bid for FIRs was determinative of whether the augmentation would be developed or not. While this would allow the TNSP to self-justify bidding for the rights, it could increase the TNSP's regulatory risks. This is because a subsequent RIT-T analysis may not find that the TNSP's bidding for FIRs was justifiable.

40 Second Interim Report, p.41.

5 Conclusion

The OFA proposal has been put forward by the AEMC to address a number of perceived flaws with the existing market design and transmission regulatory arrangements.

Perhaps more importantly and contrary to its stated intentions, the OFA proposal implies a profound centralisation of decision-making power over the planning of and investment in new generation and transmission infrastructure compared to the present arrangements. Rather than being a 'market-led' approach to development of the transmission network, it puts more faith in the views of TNSPs than does the current regime. This represents a clear and unavoidable drawback of the proposal and reason enough for its abandonment.

The OFA proposal also gives rise to numerous governance and implementation issues. These issues would arise from the setting of firm access standards, access pricing, rights trading, the role of the RIT-T and queuing policy. Minimising the harm from these issues is likely to require the close involvement and attention of the AER. However, not only would this place enormous demands on the regulator, it would be likely to slow the process of conferring and managing firm transmission rights.

Finally, the proposal does not offer demonstrable benefits over the status quo arrangements even in the areas it directly aims to resolve. In particular, it fails to ensure firm access to support contracting and it maintains incentives for non-cost-reflective bidding and inefficient dispatch outcomes.

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