19 Efficient use of interconnectors

|  |
| --- |
| Key points |
| * The spot market in the National Electricity Market is an ‘energy only’ market, in which lower bidding generators are dispatched first. The regional spot price is set by the marginal generator’s bid in each region (state) and all dispatched generators are paid at that spot price. In theory, this leads to efficient generation. In practice, this is not always true. * In the presence of congestion, the spot price tends to be high. Under current regulations, this encourages strategic behaviour by those generators constrained by line capacity. * Rather than making bids that reflect their true cost, they bid down to the (negative) market floor price to ensure dispatch, and are paid at the high spot price. Even an inefficient generator may supply power. This is termed ‘disorderly bidding’. * Disorderly bidding can result in productive inefficiency as higher‑cost generators are dispatched to meet demand. It can also ‘shut off’ interconnectors through distorted price signals. * The long-term effects are greater, and include inefficient generator location, investment and interconnector planning. * Potential ways of addressing disorderly bidding include applying formulae to market bids in the presence of congestion, or other longer-term methods that ensure generators bid at prices that reflect true costs. * Allowing generators to purchase a given amount of guaranteed access to lines from transmission businesses (‘optional firm access’) would remove disorderly bidding incentives and introduce locational signalling to generators. (While this would introduce market signals, there would still be a need for transmission planning.) * The lack of effective inter-regional hedging products has contributed to the development of state-based electricity hedge markets. This has implications for: * liquidity in the hedge market * generators’ choice of location for new investment * the ability of generators to use any market power. * Reporting hedging positions would increase market transparency, and enable more effective regulation of market power issues, but also has some costs. * Reforms that address disorderly bidding also address the root cause of problems in the hedge market. * In particular, optional firm access would allow firm access rights across interconnectors, which could replace existing financial instruments. |
|  |

Several elements of the regulatory framework — incentive regulation, regulatory tests and planning — determine the *amount* of investment in interconnectors in the National Electricity Market (NEM). However, the *use* of interconnectors depends on the activity of market participants in buying and selling power in the ‘spot’ (or energy) market, and on congestion in intra-regional transmission lines. The way market participants manage their risk in the hedge market can also affect actual power flows. If either of the markets operates inefficiently, interconnectors could be underutilised. As such, reforms to the markets (as distinct from specific interconnector regulation) could provide benefits through promoting a greater degree of interconnection.

This chapter examines the operation of, and incentives set by, both the spot and hedge markets in the NEM.

## 19.1 The spot market

Because electricity cannot readily be stored and it is generally not possible to determine which generator provided power to which customer, the NEM operates as an ‘electricity pool’ that matches supply and demand.

The NEM is an ‘energy-only’ market, and does not include a separate capacity market.[[1]](#footnote-1) Aside from hedge contracts, generators earn their revenue solely from the spot market.

The spot market in the NEM is subject to many detailed rules, some of which are necessitated by the nature of electricity, and some of which are legacies of the development of the NEM.

### Operation of the spot market in the NEM

The general operation of the spot market in the NEM is discussed in chapter 2, but several features warrant specific mention in the context of interconnectors. Dispatch in the spot market is determined by generator bids at five–minute intervals.[[2]](#footnote-2) These generator bids are dispatched in ‘merit order’, with lowest price bids first, with progressively more expensive generation called upon until demand is met. AEMO matches these bids — subject to a complex series of constraint equations managing congestion and transmission losses — to equate supply and demand in each five‑minute period.

The market price is therefore equal to the bid of the marginal generator — that is, the last, most expensive, generator required to match supply and demand.[[3]](#footnote-3) As such, for all bar the marginal generator in a given region, any generator receives a price for their power that is higher than its bid price. Accordingly, bids determine the quantity of power dispatched from non-marginal generators, but not their revenues.

As the NEM is a ‘zonal’ market, there is a separate price for each of the NEM’s five regions.[[4]](#footnote-4) All generators and loads within a region are settled at that regional price, calculated at the nominated regional reference node (RRN). At times when demand is sufficiently low and transmission lines and interconnectors are not congested, these regional prices should equate (allowing for transmission losses). However, congestion can cause price separation between the regions. As noted in chapter 18, such ‘price separation’ occurs roughly one-third of the time and is increasingly common (although the degree of difference between prices is, in most cases, small).

A further feature of the NEM is that the energy market is ‘co‑optimised’ with the market for ancillary services (services required to ensure the stability of the power system, and facilitate its recovery following a system failure). This means that the algorithm for calculating market outcomes ensures that energy demand and stability requirements are jointly met at the lowest cost. Although this co‑optimisation might be efficient, it can lead to some outcomes that, when viewed from the perspective of the energy market alone, may appear perverse. For example, co‑optimisation can sometimes be the reason for ‘counter-flows’ along interconnectors — that is, where power is observed to flow away from a higher-priced region (in the energy market) to a lower-priced one.

## 19.2 Disorderly bidding

Bizarre outcomes can occur in the NEM. While the near-instantaneous matching of supply and demand is an impressive feat of market coordination, it is possible for the market signals to ‘malfunction’. In these cases, higher‑cost generators can sell power into the spot market, even where alternative lower-cost generators could provide this power — ‘disorderly bidding’.[[5]](#footnote-5) Although the main source of these peculiar outcomes is congestion on intra-regional lines, it can have significant effects on interconnectors.

When there is no congestion within a region, generators have an incentive to bid close to their true marginal cost. Bidding too low might result in ‘follow‑the‑leader’ behaviour by other generators competing to be dispatched, resulting in a spot price that might be lower than the generator’s marginal cost. Depending on the amount of power dispatched (and their positions in the hedge market), this could be a ruinous outcome for a generator. Conversely, bidding too high could mean not being dispatched when it would have contributed to profits.

However, congested transmission lines create different incentives. Congestion on a transmission line that links one group of generators to the network means that these generators are unable to have all of their supply dispatched. Consequently, generators not affected by the constrained line must supply more power than usual. Given the operation of the ‘merit order’ dispatch, especially at peak demand times, this will mean that a higher-cost generator will be dispatched for at least some of the power required.

Knowing that their bid will not affect the regional price and faced with limited line capacity, the constrained generators’ objective changes. They now have an incentive to bid as low as possible in order to maximise their share of dispatch on the congested line and to maximise their returns.

Since generators are able to bid a (negative) price floor, currently ‑$1000 per MWh, all constrained generators with a marginal cost below the likely regional spot price will bid at the price floor in an attempt to be dispatched. Under the National Electricity Rules (‘the Rules’), when there are tied bids, capacity is allocated to all of the constrained generators in proportion to their rated capacity. Therefore, even if one low-cost generator were able to meet the full capacity of the congested line, they would have to share supply with higher-cost generators. This results in a higher overall cost to produce electricity for the region.

Box 19.1 describes a simplified example where a line connecting two generators to the RRN is constrained. In addition to a fault or outage on a line, congestion can also arise when a new generator connects to an existing line. Where the new generator’s capacity tips the total generation supply above the existing capacity of the transmission line, the net effect is the same. That is, generators who compete for limited capacity — where their bids will not determine the spot price — will have an incentive for disorderly bidding (AEMC 2011f, pp. 210‑12). This has been observed in bidding patterns by the AER (2010c, p. 3).

The intrinsic problem is that with transmission constraints, and with the spot price set elsewhere in the region, generators no longer face incentives to bid down to their marginal costs. The duration of constraints can vary — for example, an outage for a few hours, as opposed to the time to construct new transmission to accommodate new generation. Depending on this duration, the demand conditions at the time, and the amount of supply affected, the costs can be large, but transient. While the Australian Competition and Consumer Commission (ACCC) has some powers to prevent this, in practice there are significant difficulties in identifying and addressing transient market power, which can manifest as either disorderly bidding, or the more ‘traditional’ withholding of supply. (Generators have a legal right to change their bids, and there may be many legitimate reasons for doing so.)

Though disorderly bidding can cause a range of problems *within* a region, for the purposes of this inquiry, the main focus is the potential impact on the performance of interconnectors (described in a simplified example in box 19.2).

In the spot market, generators in one region receive the *spot* price of that region, even if they ‘sell’ their power (by contract) to another region across an interconnector. They may buy hedge products such as ‘inter-regional settlement residues’, to attempt to align their returns with prices in the other region, as discussed below. However, current methods of hedging across regions are imperfect. Generators in an unconstrained region face the ‘normal’ incentives to disclose their true marginal cost when bidding, while those in regions with constrained lines have an incentive to enter disorderly bids.

Regulated interconnectors cannot enter retaliatory bids (in the manner that competing generators can) and are, instead, treated as if they have bid at the RRN in the exporting region. As such, the market would perceive a low‑cost generator (with say a marginal cost of $25 per MWh) in the unconstrained region as ‘more expensive’ than a higher-cost generator in a (constrained) region engaged in disorderly bidding (‑$1000 per MWh) on the other side of an interconnector. In effect, this prevents the supply of lower-cost power across the interconnector into the higher‑priced region.

|  |
| --- |
| Box 19.1 Disorderly bidding within a region |
| Box 19.1 Figure 1 Disorderly bidding in a single region. This figure shows how marginal costs from generators impact upon the regional reference pricing node. When there is a line constraint, the price of power is high, and the generators affected by the constraint want to bid to get the high spot price. The best way of doing so under the Rules is to set a negative price to win the bid and get dispatched. Since all constrained generators do this, they both get dispatched, despite one being more efficient than the other. |
| In the example above, the transmission line connecting G2 and G3 to the load centre at the RRN is usually able to carry over 200 MW of power. In this ‘unconstrained’ case, to meet the region’s demand of 250 MW for one hour, the dispatch solution would involve total production costs of $10 200 and would be divided amongst the generators:   * G3: 120 MW (marginal production cost $1200) * G2: 80 MW (marginal production cost $4000) * G1: 50 MW (marginal production cost $5000)   In the presence of a constraint that limits the line to the cheaper generators to 150 MW, G1 must be dispatched for more power (100 MW up from 50 MW). In this situation, G2 and G3 know that their bids will not affect the regional price, so their only incentives will be to maximise their dispatch, not reflect their marginal costs. Both generators will attempt to undercut each other, resulting in bids of -$1000. G2 and G3 will then be dispatched in proportion to their rated capacity. This changes the dispatch solution:   * G3: 90 MW (marginal production costs $900) * G2: 60 MW (marginal production costs $3000) * G1: 100 MW (marginal production costs $10 000)   This results in a total production cost for power in the region of $13 900.  If bids represented ‘true’ marginal costs, G3 would be dispatched for 120 MW, G2 for 30 MW and G1 would still supply 100 MW. This ‘constrained optimisation’ solution has a total production cost of $12 700. As such, in this example, the ‘cost’ that can be assigned to disorderly bids is $1200 (with the remaining $2500 due to the constraint). |
| *Source:* adapted from AEMO (sub. 32). |
|  |
|  |

|  |
| --- |
| Box 19.2 Disorderly bidding between regions |
| Box 19.2 Figure 1 Disorderly bidding between regions. This figure shows how constraints on lines impact on marginal costs between regions. Sometimes the process described above can affect power transferring along an interconnector, stopping or reversing the flow.  As in box 19.1, when faced with a constrained line and competition from other generators (whose power must be transferred over an interconnector from region 2), G2 will enter a bid of -$1000.  In region 2, the marginal bid has set the region’s spot price at $50 and, regardless of any power supplied to region 1, a generator in region 2 can only earn $50 per MWh. As a regulated interconnector cannot ‘retaliate’ in the market dispatch engine’s calculations (by also making a bid of -$1000), G2’s bid of -$1000 will be treated as a cheaper bid. As such, G2 will run in preference to all generators in region 2, even though there may be many generators with a marginal cost of at least half the fuel cost of G2. This effectively ‘cuts off’ the interconnector.  In more extreme cases, G2 could export power to region 2, resulting in counter-flows, with AEMO attempting to ‘clamp’ the flow (see text). |
| *Source*: AEMO (sub. 32). |
|  |
|  |

Disorderly bidding is most likely to occur during periods of peak demand — when lines are more likely to be constrained and when higher‑cost ‘peak’ generators are more likely to be called on to meet demand. Ironically, it is precisely at these times when interconnectors should be in most use.

In some circumstances, an even more peculiar outcome arises. A high‑cost constrained generator bidding at -$1000 per MWh is almost certain to have spare capacity (that cannot be dispatched to its RRN due to an intervening constraint, but could be dispatched in another direction). Depending on the architecture of the network, its spare capacity could be sent across the interconnector, displacing lower-cost generators in the other region. In these instances of ‘counter-flow’, the availability of the interconnector accentuates the inefficiency of the disorderly bidding.

When counter-flow occurs, negative inter-regional settlement residues (section 19.5) can accrue. To avoid this, AEMO is obliged to ‘clamp’ (artificially reduce) the interconnector flows to zero.[[6]](#footnote-6) The presence of this obligation is one indicator of the prevalence of disorderly bidding as a problem in the NEM.

### Size of the problem?

While disorderly bidding is a well-known phenomenon within the NEM,[[7]](#footnote-7) some people question whether it matters enough to require a regulatory remedy.

Following the Commission’s draft report, several participants — including the National Generators Forum (NGF, sub. DR93), Hydro Tasmania (sub. DR96) and the Clean Energy Council (sub. DR97) — reiterated this view. They expressed concerns that disorderly bidding was not a ‘material practical issue’ (sub. DR96, p. 4) and that the Commission’s proposed solution (discussed below) was ‘far from proportionate to the problem’ (sub. DR97, p. 4). In particular, the NGF submitted AEMO data to argue that the cost of congestion was falling and noted that the ‘cost of $22 [million] in 2011 is very small compared to the energy turnover of the NEM of $5500 [million]’ (sub. DR93, p. 7).[[8]](#footnote-8) However, disorderly bidding gives rise to a range of costs.

The largest and most immediate effect of disorderly bidding is transfers between parties (between generators and, in cases where the region’s spot price increases, between generators and customers). For example, AEMO cited one instance where disorderly bidding lasting just a few hours (from 10.30 am to 5.30 pm) had a substantial impact on prices, and on the overall amount paid for power in New South Wales. In this instance, a constraint on the 70/71 transmission lines between the Mt Piper and Wallerawang power stations, combined with generators’ bids, led to spot prices in New South Wales in some instances in excess of $5000 per MWh, and saw the dispatch engine attempting to reverse interconnector flows away from New South Wales (AEMO 2010g, p. 11). AEMO estimated the revenue impacts of this case of disorderly bidding by comparing the actual outcomes with a ‘re-run’ of the dispatch model using assumed ‘normal’ bidding conditions.[[9]](#footnote-9) AEMO concluded that:

NSW prices between 10:30AM and 3:30PM averaged $90/MWh in the re-run against the actual average of $4917/MWh, which would have reduced pool settlement by about $300 [million]. (2010g, p. 11)

Another example, from 4 February 2010, highlights the interaction between network effects, disorderly bidding and demand response, and the effect this has on price volatility and interconnector flows (box 19.3).

Some have argued that the impact on prices is largely a ‘wealth transfer and not a loss of economic efficiency’ (Frontier Economics 2012, p. 7). While the wealth transfers are larger and simpler to quantify, there are some efficiency effects.

In the short term, productive efficiency is lower for the period of disorderly dispatch, as progressively less efficient generators must be relied upon to meet demand (with the inefficiency mainly being the use of higher‑cost fuels). As (the bulk of) current generation technologies and fuel sources in the NEM are relatively homogeneous, the differences in short-term marginal production costs are probably not significant.[[10]](#footnote-10)

|  |
| --- |
| Box 19.3 Disorderly bidding in New South Wales on 4 February 2010 |
| Early in the day of 4 February 2010, part of the network in Sydney’s Central Business District (CBD) was taken offline for planned maintenance. By mid-morning, potential overloads were identified between the CBD and Sydney South. To remedy these overloads, the line from Kemps Creek to Sydney South was taken out of service at 10.25 am. Flow-on effects through the transmission network then saw flows exceed limits on the Mt Piper to Wallerawang transmission lines (160 kms west of Sydney).  The figure below depicts prices during the morning of these overloads. In the face of the line constraint, the quantity of negative offers from generators increased, from 6200 MW at 10.30 am to 10 600 MW at 10.40 am (New South Wales aggregate demand at the time was just below 11 000 MW). The effects of the constraint set the price to $10 000 MW/h (the market price cap at the time) for three dispatch intervals from 10.30 am.  The high prices caused an apparent demand response, which saw a 540 MW reduction in New South Wales demand at around 11 am. This, combined with increasing negative offers from generators saw a dramatic drop in the five‑minute price, to the price floor of -$1000 at 11.05 am (prices are settled on 30‑minute periods, as the average of the six intervals, so actual settlement prices did not drop so severely). Following the reduction, demand rose, generators reduced their negative bids, and the price returned to nearly the price cap for four five-minute intervals.  There was another demand response (roughly 350 MW) at 12 pm, leading to a (less dramatic) fall in prices. At 12.40 pm, the Mt Piper transformer returned to service, relaxing the Kemps Creek to Sydney South constraint. As a result, unconstrained generation with a negative bid became marginal, and prices dropped to -$996/MWh at 12.45 pm.  These constraints also reversed the flow of the interconnectors. The Qld/NSW interconnector was forecast to import 1050 MW into New South Wales, but instead exported 446 MW to Queensland. Similarly, the Vic–NSW interconnector was forecast to import 1135 MW, but the constraint forced flows into Victoria of up to 1301 MW.  **Five minute price and demand, NSW, 4 February 2010**  Box 19.3 Figure 1 Five minute price and demand, NSW, 4 February 2010. This figure shows the five minute price and five minute demand over a 24 hour period, including two periods of substantial price increases. Two areas are highlighted which indicate times of demand reduction. |
| *Sources*: AER (2010d), Lerchbacher (2010). |
|  |
|  |

Additionally, when interconnector flows are reduced, stopped, or indeed reversed, by disorderly bidding, it affects the ability of market participants to hedge transactions between regions (section 19.5). This causes greater uncertainty for hedging parties, increasing the cost of hedging and flowing through to higher electricity retail prices in the long run.[[11]](#footnote-11)

While the productive efficiency costs in the short term may appear to be relatively small in the context of the NEM, they only represent one part of the total costs arising from disorderly bidding.In the long term, disorderly bidding causes a range of larger costs, though these are more difficult to enumerate than the short‑term productive efficiency costs and transfers away from consumers.

First, the reduced certainty of dispatch (and increased price volatility) due to disorderly bidding can increase the perceived risk of a generation investment, which could discourage (otherwise efficient) investment in new generation (AEMC 2011f, p. 33), and require existing generators to build a premium into hedge contracts to cover such risks.

Disorderly bidding widens the margin between the spot price and the usual bidding price of generators (which they typically bid down to their marginal costs). Generators recover their fixed costs from the revenue associated with the spot-bid price margin. Distortions in that margin will affect the future decisions of generators to invest. They could also affect maintenance and asset life decisions if a plant that is able to ‘survive’ on returns from instances of disorderly bidding (rather than by competing on the basis of an efficient marginal cost) is kept online longer than it otherwise would be. Therefore, generators will have a greater incentive to locate new investments in (congested) areas of the transmission network where they can better control dispatch outcomes through disorderly bidding.

Accordingly, existing or new generators may be located in the ‘wrong’ places to take advantages of constraints, particularly in relation to interconnectors. There is some evidence that this occurs. The AER has suggested that the Kogan Creek 760 MW capacity coal fired plant in Queensland was located to take advantage of the revenues created by disorderly bidding. The plant is located between the Queensland/New South Wales interconnector (QNI) and a congested part of the Queensland transmission network (AER 2010c, p. 12). The AER claimed that increases in output from Kogan Creek from 500 MW to 750 MW decreases power imports across QNI ‘on an almost one for one basis’, to the point that — when Kogan Creek runs at capacity — imports across QNI stop (AER 2010c, p. 13).

The NGF disagreed with the AER’s claims regarding Kogan Creek, and argued that the location was chosen because ‘the coal resource is stranded from export markets, the mining costs are extremely low and the transmission access is superior to that in competing locations’(sub. DR93, p. 14). The NGF also submitted that Kogan Creek had a lower short-run cost than any New South Wales generator. While Kogan Creek may be less costly and, thus, it would be more efficient from a NEM‑wide perspective to run, it is also located in area that allows it to take advantage of congestion, and cause the (short- and long-term) costs associated with disorderly bidding. Therefore, while Kogan Creek may not always be cheaper than every generator in New South Wales, under the current regime, whenever constraints occur, it will always have the ability to ‘block’ their supply across the interconnector.

This suggests that, even if some form of congestion pricing were implemented to correctly align incentives, generators such as Kogan Creek would be unlikely to alter their choice of location. However, there may be some cases where access to the transmission network is the marginal, and potentially deciding, factor for generators. As discussed below, an efficient transmission pricing system would account for all factors, encouraging generators to make a decision that appropriately considered all costs (including transmission costs and effects of congestion).

More recently, the AER (2012t) has analysed several incidences of congestion in Queensland, New South Wales and Victoria (box 19.4). The analysis focused on several incidents of disorderly bidding, and the resulting negative settlement residues. As the AER acknowledged:

… the negative settlement residues are only one aspect of the inefficiencies that arise from disorderly bidding. There are larger impacts in terms of non-economic dispatch and through increasing the risk profile of all NEM participants, both customers and generators. (2012t, p. 13)

The AER concluded that the current market arrangements, which create the incentive for disorderly bidding ‘are a serious problem’ and that they are ‘leading to significant inefficiencies and lessening competition between regions’ (AER 2012t, p. 3). More recently, the AER also drew attention to events in Queensland in January 2013:

In the first three weeks of January, for example, there were 80 occasions when the spot price exceeded $300/MWh, with 16 of those over $1000/MWh. These price spikes were not driven by excessively high demand but rather network constraints and the last minute rebidding behaviour by CS Energy and Stanwell generators. Once again there have been persistent counter price flows from Queensland into New South Wales … leading to almost $8 million in negative settlement residues into New South Wales during January and February 2013. (sub. DR109, p. 1)

|  |
| --- |
| Box 19.4 The impact of disorderly bidding on inter-regional trade |
| The AER recently analysed the impact of disorderly bidding on inter-regional trade in the NEM. The analysis examined instances of disorderly bidding and their effect on inter-regional trade between New South Wales and Victoria, and between Queensland and New South Wales. In particular, it focused on the extent of negative inter-regional settlement residues (section 19.5) arising as a result of the disorderly bidding.  Congestion and counter-flows around the Snowy  From February 2010 to September 2012, there were 12 incidents of counter-flows into New South Wales that led to more than $150 000 of negative settlement residues. These occurred following incidents of disorderly bidding that were the result of congestion elsewhere in the transmission network — for example, between Dapto and Marulan. The negative settlement residues for these incidents ranged from $156 000 to almost $17.5 million, and totalled over $25 million. The impact was less severe for counter-flows into Victoria, with eight examples totalling nearly $9 million (the largest single instance was over $5 million).  The AER drew attention to the behaviour of generators in the presence of congestion. For example, on 16 October 2012, in response to a forecast price increase, Snowy Hydro and Origin Energy rebid over 3100 MW to prices near the price floor. This led to a substantial turn-around on the interconnector, from importing 706 MW into New South Wales, to counter-flows of 875 MW into Victoria.  Congestion near Gladstone, Queensland, and counter-flows to New South Wales  From September 2011 to October 2012, congestion around Gladstone led to 24 instances of counter-flows into New South Wales that each accrued more than $150 000 in negative settlement residues. The total negative settlement residue accrued was almost $8.3 million, with the largest single instance accruing almost $1.3 million of negative residue (a counter-flow of 1257 MW at a time when the maximum spot price in Queensland was $2080/MWh).  In analysing these instances, the AER highlighted the volatility in prices. For example, on 25 August 2012:  Queensland 5-minute prices were extremely volatile, fluctuating between $1493/MWh and ‑$1000/MWh. The 5-minute price exceed $900/MWh on nine occasions and fell below ‑$300 on 21 occasions. (AER 2012t, p. 16)  As the AER noted, such volatility leads to uncertainty for the market, increases the costs of hedging and can deter new entry (section 19.5). |
| *Source*: AER (2012t). |
|  |
|  |

The analysis also highlighted an additional cause of concern. As noted in chapter 18, due to the Rules and the presence of disorderly bidding, interconnectors can be of little use at times when prices in one region are highest — that is, precisely at the times when they could be of most use. Specifically, the AER drew attention to the proportion of trading intervals at times of high price differences where counter-price flows occurred across the interconnectors in the NEM (table 19.1). As the data indicate, since 2009–20, total counter-flows at times of high prices have been a more significant issue when prices were higher in Queensland than in New South Wales, and when prices in Victoria were higher than in New South Wales. Counter-flows appear to have been infrequent across the South Australia‑Victoria interconnector (as noted in chapter 18, concerns in South Australia centre on issues of the exercise of more ‘traditional’ market power).

Table 19.1 Imports across interconnectors during high price periods**a**

|  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- |
| Relative regional spot prices | Number of counter-flow intervals (number of trading intervals) | | | | | Proportion of (total) trading intervals with counter-flows |
| 2009-10 | 2010-11 | 2011-12 | 2012-13 | Total | (per cent) |
| Qld > NSW | 9   (41) | 19  (19) | 48 (60) | 17 (17) | 93 (137) | 68 |
| NSW > Qld | 24 (131) | 2  (63) | 0  (5) | 0 (20) | 26 (219) | 12 |
| NSW > Vic | 23 (172) | 3 (108) | 2  (6) | 4  (5) | 32 (291) | 11 |
| Vic > NSW | 27  (69) | 9    (9) | 0  (1) | 4  (6) | 40  (85) | 47 |
| SA > Vic | 1 (110) | 0  (34) | 2 (27) | 1  (9) | 4 (180) | 2 |

a The table analyses metered interconnector flows for trading intervals where neighbouring region prices differ by more than $100/MWh. Data for 2012‑13 were current at 14 November 2012.

*Source*: AER (2012t, p. 19).

An additional cost from disorderly bidding is to increase Transmission Use of System (TUoS) charges. As the AER noted (2012t, p. 21), proceeds from the settlement residue auctions go to Transmission Network Service Providers (TNSPs) to offset the transmission charges they pass on to users. To the extent that disorderly bidding nullifies the value of settlement residue auctions, and so reduces the proceeds from the auctions, there are fewer proceeds available and, as such, transmission charges borne by users will increase. Further, in cases of negative residues, the TNSP in the importing region is required to fund the shortfall through charges to its end users. Increasing the TUoS represents a transfer from consumers to generators, rather than a direct efficiency cost. However, as noted above (and in chapter 17), in the long term, repeated transfers can act as incentives and, therefore, can have associated real efficiency costs. Further, (as noted in chapter 18), unless there is some offsetting efficiency gain associated with such transfers, a system of rules that allows (and encourages) this behaviour would not be consistent with the National Electricity Objective (NEO).

Additionally, common ownership of even structurally separated generation and transmission could potentially delay responding to the need for a transmission upgrade.[[12]](#footnote-12)

Finally, the observed flows on an interconnector act as inputs into transmission planning processes. Where flows are artificially reduced by disorderly bidding, forward planning about the need for (or size of) upgrades for interconnectors and intra-regional transmission lines can also be affected. This can effectively ‘entrench’ existing inefficiencies, as a presently underutilised interconnector (even if due to quirks of the sort described above) can lead to future underinvestment.

Overall, while the short-term efficiency effects of disorderly bidding may appear small, the longer-term effects on financial markets, generator location, interconnector flow and planning are of (significantly) greater concern. Given that, there are compelling grounds to ensure that any future framework for transmission planning and pricing addresses disorderly bidding.

## 19.3 Potential solutions

An efficient solution to disorderly bidding should motivate generators to make bids close to their ‘true’ marginal costs at the point of generation. There are many possible options for achieving this, with tradeoffs between their effectiveness and their ease of implementation.

At one end of the spectrum is the imposition of a formula on generator bids at times of congestion. A simple approach would be to use the historically observed ‘system normal’ bidding behaviour of generators. Alternative methods include de-linking generators’ returns from the regional price in the presence of congestion, for example by setting the price of their dispatched supply according to their ‘nodal’ (or local) price, potentially packaged with hedging options.[[13]](#footnote-13) By removing the incentive to bid low in order to maximise dispatch, such imposed formulae can resolve the short-term dispatch efficiency issues caused by disorderly bidding. However, they are not necessarily the best method for dealing with longer-term issues such as generator investment and location.

Alternative approaches taking a long-term view can still realise the short-term benefits of these simple options, but can also more directly influence the timing and, particularly, the location of generator investments, introduce greater market signals to transmission investment and improve the alignment of generation and transmission investment. Improvements in these factors would have subsequent benefits for interconnector use and investment.

Various reviews have canvassed long-run solutions. Of most relevance is the AEMC’s current Transmission Frameworks Review (TFR). The TFR is examining three aspects of the regulatory framework for transmission: generators’ certainty of access to the regional reference price, transmission planning, and arrangements for connecting generators to the network. Of these, the options for generator access are relevant to disorderly bidding issues.

In the first interim report of the review (AEMC 2011f), the AEMC contemplated five packages for reform of generator access to the network.[[14]](#footnote-14) In the second interim report (AEMC 2012j), the AEMC focused on two options:

* Optional firm access (OFA) in which generators can purchase from a TNSP a privileged financial right to a given amount of the capacity of a transmission network (‘firm’ access). The generator does not have to actually dispatch power, but any other generator displacing the purchased capacity must pay the generator that has acquired firm access. In this way, firm access provides firm *financial* access (as distinct from physical access) to the regional reference price through a compensation mechanism.
* Non-firm access — effectively the status quo. It would not prevent disorderly bidding and its associated significant problems.

Of these, only the first (optional firm access) can address the long-run inefficiencies due to disorderly bidding and is the Commission’s preferred option.

### The optional firm access reform package

The OFA package proposed by the AEMC is a complex and integrated package that aims to address several key issues, including disorderly bidding, dispatch certainty for generators, locational signals for generators and the lack of market signals for transmission operation and planning.

The key features of the AEMC’s package (AEMC 2012j, pp. 22‑3) are as follows:

* *Purchasing firm access:* generators would have the option of purchasing a quantity of ‘firm’ access from TNSPs, or leaving all (or part) of their output subject to non-firm access.
* *Access pricing:* there would be no charge for non-firm access, but firm generators would pay TNSPs a charge reflecting the long‑run incremental costs (LRIC) of increasing the network capacity over time. LRIC is one method of calculating (the broader principle of) long‑run marginal cost (Marsden, Jacob and Associates 2004).[[15]](#footnote-15) (Chapter 11 discusses the concept of long‑run marginal costs in detail.)
* *Firm access standard*: TNSPs would be required to plan and operate their network to provide a level of capacity necessary to meet the purchased levels of firm access(analogous to customer reliability standards, but targeting outcomes that matter for firm generators).
* *Access settlement*: where non-firm generators are dispatched ahead of firm generators, they are liable to compensate firm generators for any loss of dispatch. In this manner, ‘firm’ access refers to certainty of financial return, rather than physical dispatch. This settlement process affects generator bidding behaviour in a similar manner to congestion management mechanisms, and reduces incentives to disorderly bid.[[16]](#footnote-16)
* *Inter-regional access:*Generators and retailers could purchase firm inter-regional access rights for a given amount of capacity on interconnectors. These purchases (combined with bids from other beneficiaries) would be used to direct and fund future interconnector expansions (this element of the package is discussed further in chapter 20).

The package also requires additional regulation of TNSPs as the monopoly providers of firm access. This regulation would include (AEMC 2012j, pp. 35‑7):

* requirements to provide information to generators requesting firm access in a timely manner, and to negotiate in good faith
* transparency of any approved LRIC pricing methodology
* changes to revenue regulation. TNSP revenue from firm access sales would not be capped, but the prices for firm access would be regulated (to ensure the methodology used was consistent with LRIC). Instead, an estimate of the expected revenue from firm access charges would be ‘carved out’ from total revenue requirements, leaving the remainder of the revenue cap to be spread across users of load services through transmission use of system charges
* quality regulation in the form of financial incentives that penalise TNSPs for shortfalls in providing the subscribed levels of firm access. These financial penalties would be transferred to affected generators through the access settlement process.

The AEMC’s OFA package also includes a lengthy transition process that calculates generators’ access requirements, scales them back to the existing capacity of the shared network, and gifts generators with (temporary) firm access based on their past use. These transitional access rights would be removed progressively over a period of up to five years, or over at least the remainder of the existing regulatory determination period (AEMC 2012j, p. 39). During the transition phase, TNSPs would also be exempt from financial quality incentives.

Sudden changes in regulation can create uncertainty and confusion amongst stakeholders, particularly in the case of a complex reform to an already complex area, such as electricity. The approach suggested by the AEMC aims for a smooth transition by phasing in changes through endowing generators with initial firm access rights. This would allow generators (and TNSPs) to ‘learn’ and become accustomed to the reforms over time. On the other hand, providing all generators with an endowment based on existing use could simply delay the benefits of optional firm access and (temporarily) create a more complicated version of the status quo (with no relativity in access pricing to induce changed investment decisions by generators). This could also risk locking in current patterns of transmission use, thus potentially ‘locking out’ interconnectors. Avoiding the ‘lock in’ of the status quo is one consideration that should be borne in mind during the implementation process (discussed below).

While the OFA package is wide-ranging, its most important elements are the access settlement process, and the ability to pay for firm access (on both intra- and inter-regional lines).

### The access settlement process — a congestion management mechanism

The access settlement component addresses transmission congestion. Through a series of complex formulae (AEMC 2012n, p. 103)**,** the access settlement process provides compensation to firm generators who were not dispatched due to congestion. The compensation is paid by the (generally) non-firm generators who contributed to the congestion. This settlement process is a transfer between generators that operate separately from the market dispatch process (which would continue to function as it does now). As such, the settlement process does not increase the total price the wholesale market pays for electricity. In fact, it is designed to address disorderly bidding and encourage generators to bid at their marginal costs, reducing overall costs.

The compensation for generators takes the form of the ‘flowgate price’ for each MW of firm power that is not dispatched.[[17]](#footnote-17) The flowgate price is the marginal benefit of relaxing a constraint affecting the flowgate.[[18]](#footnote-18) This is equal to the amount that the market currently pays for that marginal MW (the regional reference price) less the cost of a ‘cheaper’ MW that could be accessed from the generators using the constrained flowgate — the locational marginal price (LMP) of the affected generators). Where a firm generator is the marginal generator at its node, and enters a bid equal to its marginal cost, the flowgate price will be the same as the profit margin that the constrained firm generator would receive from dispatching that MW. Therefore, firm generators’ profits are the same regardless of whether they are dispatched or not, eliminating any incentive for firm generators to enter disorderly bids.

Conversely, other generators must pay compensation equal to the flowgate price for each MW where their dispatch amount exceeds their own firm access entitlement (which may be zero). If a non-firm generator entered a disorderly bid, they would still receive the regional reference price, but would incur their costs for units produced, and would also be liable to pay compensation through the settlement process. This would lead to losses and therefore remove the incentive for disorderly dispatch. Where the non-firm generator is more efficient than a firm one, they would still pay compensation, but should still profit from being dispatched (box 19.5).

Where a given flowgate (or indeed, the entire NEM) was used by only non-firm generators, their entitlements would be a proportion of the available transmission capacity, based on their available generation capacity. So, if two generators of 600 MW and 400 MW capacity sought to use a transmission line of 500 MW capacity, their respective ‘entitlements’ would be 300 MW and 200 MW. The degree (and direction) of compensation flowing between non-firm generators would be determined by the difference between this (implied) entitlement and the dispatch amount for a given generator.

For a non-firm generator to profit from being dispatched, rather than staying idle (and regardless of the presence of any firm generators), its marginal cost must be less than the LMP. In this way, the access settlement mechanism ensures that, even in the presence of congestion, generators have an incentive to bid in a manner that reveals their true marginal costs. As such, adoption of the OFA package would ensure that, at the very least, a congestion management mechanism would apply in the NEM. This element alone should address disorderly bidding and provide (at least short-term) benefits.

|  |
| --- |
| Box 19.5 The access settlement process |
| Box 19.5 Figure 1 The access settlement process. This figure shows the process of dispatch and energy settlement between nodes on a constrained line under the 'optional firm access' model.  If the line between node X and node Y is constrained, the combined dispatch of G2 and G3 cannot be more than 100 MW. With a lower bid, the non-firm generator (G2) is dispatched ahead of the firm generator (G3), constraining G3 off by 50 MW.  Dispatch and energy settlement occurs as it does currently, with the regional reference price set at $100 by the marginal G1, who dispatches 100 MW, and receives $10 000. G2 dispatches 50 MW for $5000 and G3 50 MW for $5000, for a total of $20 000.  Given G2’s usage of the constrained flowgate (50 MW) exceeds its entitlement (0 MW), it will be required to pay compensation in the *access settlement* process (separately from *energy settlement*). As G3’s usage (50 MW) was below its entitlement (100 MW), it will receive compensation, calculated as entitlement minus usage, multiplied by the flowgate price ($40). After compensation, the generators’ revenues are:   * G1 is not affected by the constraint, so it receives only the energy settlement: $10 000 * G2: receives energy settlement, *minus* compensation: $5000 – 50\*$40 = $3000 * G3 receives energy settlement *plus* compensation: $5000 + 50\*$40 = $7000   Assuming G3’s bid is its marginal cost, if it was dispatched for the extra 50 MW, it would have received $5000 more, but incurred costs of $3000, for additional profits of $2000. So the compensation has put G3 in the same financial position as if it were dispatched.  G2’s incentives depend upon its marginal costs. If its costs are below the local price ($60), then it will profit. If its costs are $60 per MW, it will be indifferent. If its costs are higher than the local price (say $70 per MW), but it bids below the local price, it will be dispatched (and receive $5000), incur production costs ($3500) and owe compensation ($2000), resulting in an overall loss (-$500). In this way, the access settlement process discourages disorderly bidding. |
| *Source*: adapted from AEMC (2012j). |
|  |
|  |

### Procuring firm access — a long-term signal

Under the OFA package, the ability of generators (and in the case of regulated interconnectors, retailers) to purchase a quantity of firm access from TNSPs would operate as a two-way signal.

For transmission companies, the signals are firm access requests by generators. This creates ‘market-driven’ signals for transmission investment because generators in a competitive environment seek investment to meet their needs. It avoids sole reliance on planning by a TNSP. This should lead to a better alignment of transmission investment with generation needs. Further, procurement of large quantities of lines by generators is less of a social concern than any potential ‘gold-plating’ by TNSPs under the current economic regulatory regime. As generators generally operate in a workably competitive market, any incorrect decisions to procure firm access will result in fixed costs that are not fully recouped through the wholesale market, with the loss being borne by generation owners, rather than spread across all users through increased transmission charges.[[19]](#footnote-19) Thus, those making the decision would bear the risk. Similar benefits would arise from generators and retailers being able to purchase firm access across interconnectors.

For generators, the prices charged by TNSPs for firm access act as the market signal. Provided regulation prevents TNSPs from using their monopoly position to increase charges, prices should reflect the net present value of the LRIC of providing the requested capacity. The use of the LRIC should provide two important signals (AEMC 2012j, p. 32):

* *Locational*: where longer transmission lines would need to be built, generators in remote locations would pay a higher price than those close to loads (or the RRN).
* *Congestion:* where a generator located in a congested part of the network, and requested firm access, expansion of transmission lines would be immediately required for the TNSP to provide the requested firm access. Where a generator located in an area of substantial spare transmission capacity and sought firm access, any necessary investment would be a long way into the future. As such, the net present cost of locating in an uncongested area would be lower than in a congested area.

Cost-reflective pricing of firm access ensures that location and congestion would be one element of the overall decision to invest in new generation. Other factors, such as proximity to natural resources or load (demand centres), may often be more important. Consequently, generators could still choose to locate in relatively congested areas. The difference is that, under the OFA package (through both access pricing and the settlement mechanism), the generator should have considered all the appropriate costs and (provided they did so wisely) made a decision that was, overall, an efficient one.

### Optional firm access and transmission planning — complements or substitutes?

The network transports power from generators to load centres. Under the OFA package, the generation side of transmission investment is driven by the market signals described above. This raises the issue of how OFA interacts with, or indeed if it replaces, transmission planning arrangements.

While the introduction of market signals would improve the coordination of generation and transmission investment, it would not necessarily result in optimal network development. For it to do so would assume that users’ interests were directly aligned with suppliers’, and that generators were motivated to demand transmission investment at the right place, and at the right time, for consumers.

Although markets within the NEM can achieve impressive feats of coordination, their present structure does not result in a complete alignment of generator and user interests in terms of transmission investment. For example, generators’ financial interests rely on delivering power to a RRN. As such, their firm access requests will relate to lines between generators and the RRN. Load centres that require transmission from the RRN with little to no local generation may be under-provided if transmission investment were solely directed by generators.

In the future, were the demand side able to obtain firm access (through for example, retailers requesting and paying for firm access), these concerns could be alleviated as transmission could be more directly driven by consumer need. However, in order to do so, customers would need to (at least partly) face cost-reflective prices. Given the NEM-wide introduction of cost-reflective pricing could take a considerable time (chapter 11), retailers would not see any degree of efficient response to price changes (in timing or quantity of use) for some time. Consequently, any signals they would be able to send through purchasing firm access would also be distorted.

Further, even in the presence of (undistorted) signals from both sides of the market, there is likely to be a role for some independent oversight of the planning of the transmission network (whether it be the current system, or the Commission’s model of probabilistically-based reliability standards and contingent projects as recommended in chapter 16).

As discussed in chapter 16, it is difficult to correctly align the incentives of private actors (with limited liability) with potential high impact, low probability events. While generators (and retailers) would have some incentive to avoid such catastrophes, they would not bear the full costs of protracted and widespread blackouts (if, say, transmission lines to Melbourne or Sydney were to go down for an extended period). Given the possibility of such extreme consequences, and the inability with transmission to be able to confidently use lead indicators to monitor the reliability of the network, some planning oversight would still be necessary over the long run.

There would also be precautionary grounds for detailed planning and identification of constrained transmission lines for at least an interim period. While it appears to be elegant and theoretically sound, OFA may not work perfectly and, if implemented, should be evaluated before contemplating the removal of the role of detailed planning and independent probabilistically-based reliability standard‑setting. The Commission also notes that even systems in the United States that use full nodal pricing retain at least some role for a regional transmission planner.

However, having both transmission planning and OFA mutes the benefits available from each. For planning, any benefits available from improved coordination would only apply to a subset of the network, as transmission investment for generation would be market-driven. For the OFA package, the presence of lines built to meet reliability standards introduces complications. While there may be some radial lines in the NEM that carry power solely to a load, or some that only serve generators without load centres, the bulk of lines will serve both generation and load. As such, it may be possible for some generators to ‘free ride’ on the capacity that is built for (and paid for directly by) load. Indeed, the OFA package contemplates a mix of firm (that is, paid) and non-firm generators.

Not all generators would free ride. Peaking generators that depend on access to the RRN at peak times would still have strong incentives to purchase firm access. However, some baseload generators that rely on average returns may have incentives to stay non-firm and operate on the planned network. As the AEMC (2012n, p. 87) noted, given the presence of excess generation capacity, not all non‑firm generation would need to be accounted for in building the network to meet peak demand. This would make free riding on ‘reliability’ lines a somewhat risky proposition.[[20]](#footnote-20)

Another source of risk for non‑firm generators, even in areas of excess transmission capacity, would be the potential for entry by new generators. In uncongested areas, a new entrant could receive firm access for a relatively low price. A new firm entrant would not only reduce the non‑firm incumbent generator’s energy market returns in the short-term, but would also increase the cost of any future firm access that incumbent may wish to purchase (as that access would now require more immediate additional transmission investment, increasing the LRIC). To prevent this, the non‑firm incumbent would have an incentive to pre-emptively purchase firm access as a ‘defence’ against new firm entrants, further reducing the extent of free riding.

Nevertheless, while some free riding could erode the benefits of the OFA package, particularly in relation to generator location signals, it is unlikely to eliminate them. For instance, the benefits from addressing disorderly bidding would remain.

Further, an independent party with the knowledge of the network could be an additional source of information for generators, on issues such as the (long‑term) upgrades required to meet firm access requests, and indicative costings of similar upgrades. This would limit the ability of TNSPs to price above cost. AEMO seems well suited to perform such a function. Such a role complements AEMO’s existing national roles and the roles recommended by the Commission for AEMO to take on. These include roles as national reliability standard-setter, national planner and planner of last resort (chapter 16), and providing expert input to the AER in regard to the Regulatory Investment Test for Transmission (RIT-T, chapter 17).

Overall, the Commission considers that the benefits of the OFA package would still be significant even in the presence of transmission planning.

### Design matters

As can be expected at the early development stage of a significant and complex model, several detailed design issues with the OFA package are, as yet, unresolved. Participants’ responses to the AEMC’s second interim TFR report have raised a number of issues with the OFA package. While the Commission does not intend to address every detailed matter relevant to an ongoing process, some of the criticisms of the OFA package, particularly those that relate to aspects of the market power possessed by TNSPs, bear discussion.

#### Market power — access pricing

As discussed above, under the OFA model, generators would be charged a price for firm access, based on LRICs. Where the access price is formulated appropriately, generators’ incentives to locate (and bid) would be correctly aligned. However, there is an issue relating to responsibility for setting the access price.

The NGF (sub. DR93) raised concerns that allowing TNSPs to set the access prices would not be efficient, as it may present TNSPs with incentives to misprice the upgrades necessary to provide access, and would lack transparency, denying other stakeholders the opportunity to comment on assumptions made in the pricing process. These concerns could be exacerbated due to the fixed nature of access pricing, as the level and cost of access could vary over time, leaving generators potentially bearing a risk of an unnecessary cost. However, any risks that OFA could introduced must be compared with the risks inherent in the current system, including a significant volume risk for generators (undermining both their spot and hedge market returns) if they are not dispatched due to network congestion (and the bidding behaviour of other generators). Under the OFA package, generators can purchase a mechanism to manage this dispatch risk. Given that generators are sophisticated players in a workably competitive market (well‑practised in managing risks from other large purchases such as plant and equipment), they are better placed than consumers (who would otherwise bear an increase in TuOS charges if additional investment were needed) to assess and bear such risks.

Both the Clean Energy Council (sub. DR97, p. 15) and the AER (2012w, p. 8) had similar concerns regarding the risk of a TNSP calculating the LRIC in a way that exercised market power (by charging generators too much), or in a manner that allowed them to build more assets than would be efficient (by charging generators too little).[[21]](#footnote-21) AEMO also noted its concern that negotiating firm access with TNSPs would ‘simply compound the disadvantages that generators face … [in] dealing with limited transparency from monopoly service providers’ (sub. DR100, p. 12).

In terms of mitigating such disadvantages, the AER went on to suggest AEMO be given the role of determining access pricing, noting that:

… AEMO will be able to take a nationally consistent approach and will be able to utilise its generation sector expertise. The AER also considers that there are benefits arising from AEMO’s independence as a decision maker. (2012w, p. 8)

At the time of the second interim report, the AEMC envisaged that a ‘consistent pricing methodology, to be applied across the NEM, would be developed during implementation of the OFA model’ (2012j, p 32). They also acknowledged that the governance arrangements would require ‘further consideration’. Of note, the (staff) technical report attached to the second interim report of the TFR, seems to contemplate the involvement of AEMO (though notes some drawbacks):

… it would arguably be preferable for pricing of access requests to be undertaken by a NEM-wide institution which had a NEM-wide transmission model and demand and generation forecasts.

On the other hand, …. [r]equiring a third party to undertake pricing in [the access procurement] process has the potential to make it much less effective and timely. (AEMC 2012n, p. 45)

The AEMC’s presentation at a consultative forum (2012q, p. 29) also indicated that responsibility for access pricing was, at the time, an open question. Clearly this is an issue that should be resolved as part of the implementation of the OFA package. As noted below, the Commission considers that AEMO can play an informational role to allay the (valid) concerns that TNSPs could use their market power (and exploit information asymmetries) if they had the unfettered ability to set access prices. The involvement of AEMO should also encourage consideration of NEM-wide issues for any given access request.

The provision of information by AEMO is not a ‘hard’ control on TNSPs. However, as noted by both the AEMC (2012j, pp. 36‑7) and the AER (2012w, p. 8), there may be scope to develop mechanisms that allow the TUoS (effectively, customer side) revenue cap to be adjusted where access pricing (rather than the quantity of access requested) led to a shortfall of revenue compared with costs. This could operate in a manner similar to the contingent projects process. Further, the AER could draw on AEMO’s information in assessing the appropriate value of firm access expansions to roll into the RAB.

However, more direct (and timely) controls are likely to be more effective than relying on ex post methods. As the AEMC envisaged (2012j, p. 32), there would be a single, NEM-wide methodology for access pricing. This would be developed, essentially as a guideline, during the implementation of OFA. Once the guidelines are developed and the OFA model is in place:

* TNSPs could calculate pricing schedules according to these guidelines
* AEMO would analyse these prices (with particular consideration given to inter‑regional effects) and publish their analysis, to inform both the market and the AER. The analysis could include benchmark costs of a range of transmission upgrades. Generators would also be able to access information of the costs of analogous (non-firm access) upgrades through the publication, by both TNSPs and AEMO, of RIT‑T documentation.

In addition to initial guidelines for pricing, and the provision of information, one critical remaining issue is the degree of explicit price regulation required. While OFA should ensure that the highest-value users receive the access levels they desire, as noted above, allowing TNSPs sole responsibility for access pricing leaves the system open to the use of market power. There are several possible ways to address this:

* In line with the Commission’s approach for general transmission planning (chapters 16 and 17), for ‘major’ requests (where at least one option to give effect to the request would involve a long-run incremental cost of $38 million or more), the AER could conduct a detailed cost–benefit analysis and approve the pricing of the individual access requests.[[22]](#footnote-22) For small firm access requests, the AER could approve the pricing *schedules* (though not individual prices). The AER’s decisions on access pricing should take account of the need to encourage investment, as well as encouraging efficient locational decisions by generators.
* Alternatively, the AER would approve the pricing *schedules* for all firm access requests (but not individual prices) in a manner analogous to the current pricing proposal process for general transmission pricing.[[23]](#footnote-23) By not requiring the AER to approve any individual prices, this option avoids some ongoing administration and compliance costs. However, it also represents a ‘lighter’ regulatory control, relying instead on transparency and a limited degree of generator choice (between which RRN they seek access to, and the quantity of access they seek) to curtail any excessive access pricing.

The choice between these two options (or indeed other alternatives that could adequately address market power issues) is complex, and depends on the degree of market power, the ability of transparency to overcome information asymmetries and the extent to which generators have any choice in their access requests. At this stage, it is too early in the development of the OFA model to determine which is the best mechanism for curtailing market power without incurring unnecessary costs. As such, the Commission considers that more analysis of this matter should occur in the lead up to the implementation of OFA.

#### Is firm access truly ‘optional’?

Both the NGF (sub. DR93) and Biggar (2012) noted that the access settlement implications for non-firm generators competing with firm generators create a ‘prisoners’ dilemma’ where, if one generator procures firm access, other generators would be worse off if they did not follow suit. Therefore, in anticipation of other generators’ actions, it is likely that all generators will procure firm access.

The AEMC were aware of the incentive effects that the OFA package would create, and considered that OFA would lead to one of two equilibria, one where all generators are firm, and one where all are non-firm (AEMC 2012n, p. 83). They go on to note that, in the case where all generators are non-firm, it is likely that access costs will be low, which could encourage some generators to purchase access. This suggests that an equilibrium where all generators are firm is more likely.

In effect, purchasing firm access is ‘optional’ in the same sense that participating in the hedging market is for generators. That is, it is not a strict requirement to purchase access (or engage in hedging to manage risk), but commercial imperatives strongly encourage generators to do so. But OFA is not a mandatory ‘entry fee’ of a set amount for all generators that must be paid to participate in the market — generators can participate in the market without any access, or choose the amount of access they seek (whether partially-, fully-, or ‘super-firm’), and manage their risks accordingly.[[24]](#footnote-24)

It is an over-simplification to assert that the optional nature of the access means that no individual party will be strictly worse off. Indeed, the implementation of OFA would see a larger proportion of costs borne by generators, whether directly through purchasing firm access, or indirectly through exposure to liability to pay compensation as non-firm generators. But, as noted above, this transfer away from generators brings with it overall improvements in efficiency both in the short term (resolving disorderly bidding) and in the longer term (improving locational signals, introducing market-led transmission planning and improving interconnector planning).

#### Technical design matters

Several other issues were raised by participants in the AEMC’s consultation process. While important, these issues are of a more technical nature. Accordingly, the Commission considers that they are more appropriately dealt with as part of the AEMC’s ongoing process. Some of the issues are presented here for illustrative purposes:

* *Using flowgate pricing to determine access settlement*: The NGF (sub. DR93, pp. 9‑10) highlighted the example of the Upper Tumut generator participating in at least 648 flowgates to access the New South Wales regional reference price. This leads to substantial complexity both in determining the access pricing (forward planning, considering the network make-up across those flowgates some 30 years into the future), and for hedging purposes (managing the risk of price differences) for generators. While the hedging market will adjust to make forward predictions of new pricing behaviours, the difficulty in accounting for multiple flowgates will affect the formulation of access pricing guidelines (and the prices themselves). As such, these matters should be carefully considered, and the subject of a transparent consultative process.
* *Generators with negative flowgate participation*: Biggar (2012, p. 5) highlighted the example where a generator has a negative participation (that is, if generator X dispatched power, it would *reduce*, not add to, congestion on line Y). In such circumstances, a different sort of mispricing occurs, and generators underprovide power. The AEMC (2012n, pp. 106‑7) is aware of this issue, which does not stem from OFA itself, but from the treatment of ‘flowgate support’ generators. The AEMC (2012n, p. 16) suggested that a corresponding system of ‘optional flowgate support’ could be ‘developed and introduced at a later date’.
* *Unscheduled generators and loads are excluded from the model*: Biggar (2012, pp. 6‑8) also analysed some of the dispatch inefficiencies that could result from unscheduled generators (such as distributed generation) and load interacting with the OFA model. As with consideration of negative flowgate participation including other market participants, particularly load, would be an appropriate consideration for a later review for any expansions to the OFA model.
* *Does the model apply to a substantial proportion of constraints?* Both Hydro Tasmania (sub. DR96) and the NGF (sub. DR93) submitted that one reason they felt that OFA would be ineffectual was that, according to their understanding ‘generators are only purchasing firmness against thermal constraints … [which] only account for about $5m out of a total of $22m (22%) [of the costs of constraints] in the latest year’ (NGF, sub. DR93, p. 7). However, based on its own consultations to date (AEMC, pers. comm., 12 March 2013), the Commission understands that OFA is intended to apply to those constraints that arise due to limitations on TNSP networks, and for which generators are not already compensated. This includes thermal and stability constraints. It does exclude some constraints, for example ‘frequency control ancillary services’ constraints (as they are not caused by *network* limitations), as well as ‘network control ancillary services’ and network support constraints (as generators are already compensated for such constraints).

#### Conclusion

While it is clear that the OFA package, as presented in the second interim report of the TFR, is by no means perfect (nor is its design yet fully complete), this should not prevent its eventual implementation. As identified in relation to market power issues, the problems are not insurmountable and should be able to be adequately considered, and remedied, during the implementation process. Nor are the problems large enough to outweigh the benefits available from introducing OFA.

The identified issues serve to illustrate that, when first contemplating significant and complex reforms intended to transfer to a new form of pricing for the market, care and time need to be taken, along with thorough consultation, to ensure that otherwise beneficial reforms do not lead to unintended consequences.

### The way forward

Disorderly bidding and the (lack of appropriate) long-term investment signals for generators contribute to congestion, affect the optimal use of interconnectors and planning for any future interconnector upgrades. If these issues were not resolved, the benefits from any further investment in interconnection would be muted at best, as generators have strategic incentives that can, under certain circumstances, frustrate the efficient use of interconnectors. Accordingly, the Commission considers that reform is warranted.

The key to any solution is mechanisms that reveal the true cost (including congestion) of generators bidding into the NEM. Changes in the Rules that remove the current perverse bidding incentives of generators would better manage congestion and remove the current distortions that lead to underutilisation of interconnectors. Upgrading interconnector capacity may not be the most efficient overall solution until these underlying incentives were addressed.

While short-term solutions such as the imposition of congestion management formulae on bidding would be beneficial, the Commission favours the OFA package option in the AEMC’s second interim TFR report, because it creates better market signals for generator location and transmission investment. While conceptually complex, the information to implement it is already available and so the implementation of the model, once finalised, should not face insurmountable obstacles. The implementation of OFA will likely transfer rents from some generators (and thus will be loudly opposed by those who expect to be affected), but that does not suggest inefficiency. In any case, the existing system leads to transfers that are arguably less defensible and, unless they provide some offsetting efficiency gains, may not be consistent with the NEO.

#### Implementation

As discussed above, OFA is a complex model. It is also an important reform for the electricity market. As such, it is equally important to allow time in the implementation of such a reform to develop the details prior to implementation, and to consult on any changes in order identify unintended consequences.

However, unnecessarily delaying the implementation of the OFA also risks sacrificing some of the benefits available from addressing issues such as disorderly bidding. Some, such as the AER (2012w, p. 9) have noted that disorderly bidding is increasing, and advocate implementing short‑term measures before the OFA itself is implemented.

In the first instance, greater restrictions could be placed on generators lowering their ‘ramp rates’ (pace at which they can be backed off by the operator). Currently, the minimum ramp down rate is set at 3 MW/minute. A low ramp rate can allow a generator to benefit from disorderly bidding for an extended period of time, as the AER noted:

… Snowy Hydro’s Tumut facility is treated as a single unit by NEMDE [National Electricity Market Dispatch Engine] and has a capacity of 1800 MW. If it is operating at its maximum capacity … (which it can reach from zero in less than ten minutes with it ramp up rate of 200 MW/min), and bids in a 3 MW/minute ramp down rate, it will take 10 hours to ramp down to zero output. (AER 2012t, p. 22)

The AER originally suggested a change to the minimum ramp down rate to 3 per cent of a generator’s capacity per minute (2012t, p. 22). This would result in larger generators being ramped down to zero at a much faster rate (18 times faster than currently in the example above). More recently, in recognition that some generators may have legitimate technical reasons for requiring ramp down rates of less than 3 per cent, the AER (sub. DR109, p. 5) suggest that generators instead be required to bid at their technical ramp rate at all times. This would require a change to the Rules, and to reduce uncertainty regarding particular rates for particular generators, would require an independent body to specify the definition of a technical ramp rate. While such changes[[25]](#footnote-25) would lower the extent of the impact of any given instance of disorderly bidding, some incentive to disorderly bid would remain.

To this end, the AER (2012w, p. 9) also suggest that a ‘short-term congestion management solution’ could be implemented before the OFA package. This could be based on the Shared Access Congestion Pricing (SACP) model (package 2 in the first interim report of the TFR). The SACP decouples the incentives for generators by settling generators at their LMP, and assigning them a share of the intra-regional settlement residue. This share is determined not by the quantity that the generator is dispatched, but rather by the generator’s availability, and the degree to which the generator’s dispatch contributed to congestion. In doing so it removes the incentives for generators to maximise their dispatch in the presence of congestion, and thus prevents disorderly bidding.

In addition to the benefits from reducing disorderly bidding, implementing the SACP has a number of other advantages:

* Market participants would become accustomed to a form of access settlement.
* In addressing disorderly bidding, the SACP would also encourage a more efficient dispatch pattern by generators, and a more efficient flow along interconnectors. These flows could be used as the basis for granting transitional access (discussed above), reducing the risk that transitional access could ‘lock in’ any existing inefficiencies.[[26]](#footnote-26)
* The Commission understands that much of the information relating to constraints that would be necessary for the SACP is already held by AEMO, who could also alter settlement systems relatively quickly (AEMO, pers. comm., 8 March 2013). Provided an expedited Rule change was undertaken by the AEMC, the time required to implement the SACP would be substantially shorter than for the OFA package.

Implementing the SACP in the short term would enable some of the benefits from reform to be accessed sooner than if OFA itself were the only reform. It also allows additional time to be taken to develop and refine the OFA package, reducing the risk of unintended consequences, a point also made by the AER:

As a stepping stone towards OFA [SACP] would also provide valuable lessons to inform the design of the more complex aspects of the OFA model such as [TSNP] incentive arrangements. It would also provide real world insights for generators prior to the requirement for those generators to choose whether or not to commit to firm access. (sub. DR109, p. 3)

Importantly, implementing the SACP before the OFA package allows for a staged implementation process for such a major reform, reducing the degree of ‘shock’ to the market.

Recommendation 19.1

As an interim measure before the potential full introduction of the Australian Energy Market Commission’s optional firm access package, a short-term congestion pricing mechanism as suggested by the Australian Energy Regulator should be introduced to the National Electricity Market.

Once the interim measure is implemented, time can be taken to fully develop the OFA model. This could be through a single, large Rule change process, involving several rounds of consultation. A more focused alternative would be a series of Rule change requests, each focused on a particular aspect of the OFA model. Importantly, although the available evidence to date (discussed above and summarised in box 19.6) suggests that the OFA model would be likely to deliver net benefits, this does not constitute a full cost–benefit analysis for what is a significant reform to the electricity market.

|  |
| --- |
| Box 19.6 Categories of costs and benefits from optional firm access |
| There is a range of costs and benefits arising from the OFA model. Importantly, transfers (including access fees to be paid by generators) are generally not considered. But the *effect* that a transfer has on (short-term) efficient dispatch and long-term productive and allocative decisions should be included in any cost–benefit analysis.[[27]](#footnote-27)  Cost of optional firm access   * *Implementation costs in developing the OFA model*: A one-off cost involving the administrative costs of reviews, Rule changes, and consultations. * *Implementation costs in changing the dispatch process*: A one-off, relatively minor, cost to adjust the dispatch engine. Note this cost would also be required for any interim congestion pricing. * *Adjusted dispatch processes, bidding and monitoring*: An ongoing cost, as generators must adjust their bidding to account for new pricing structures. Under the Commission’s recommendation, this would include administrative costs of monitoring bids by AEMO and the AER, an incremental increase on current practice. * *OFA access pricing calculations and regulation:* An ongoing cost, borne by TNSPs, AEMO and the AER.   Benefits of optional firm access   * *Improved hedging between regions and reduced counter-flows*: Improving flows along the interconnectors can reduce costs to consumers from negative settlement residues (AER 2012t) and allow for a better functioning and more ‘national’ hedging market (below), reducing the cost of risk management. * *Reduced price fluctuations:* Even isolated instances of disorderly bidding can cause price ‘spikes’. Eliminating these reduces overall risks, and thus the costs of hedging. * *Improved long-run generator location decisions*: Improved coordination between transmission and generation investment can lead to lower overall transmission costs. This saving only manifests when existing spare transmission capacity is exhausted, and as such, in present value terms could appear small at this stage.[[28]](#footnote-28) * *Improved short run efficiency of dispatch*: While there are difficulties in assessing an appropriate counter-factual, a conservative estimate (AEMO data put forward by the NGF) of the cost of congestion was $22 million. * *Reduced prices and improved allocative efficiency*: While largely a transfer, to the extent that users respond to a reduction in price (away from a distorted level), there will be some allocative efficiency gains from improved decisions by electricity users. |
|  |
|  |

Therefore, in order to properly assess the likely net benefits of the OFA model, and to demonstrate its consistency with the NEO, the Commission considers that the AEMC should conduct an initial cost–benefit analysis of the OFA model before its detailed implementation planning is commenced.[[29]](#footnote-29) So that this does not unnecessarily delay the implementation of the model, such an analysis should be completed during 2013.

At a later time, during the more detailed implementation of the OFA package, this cost–benefit analysis should be updated to focus on the additional costs and (long‑run and likely larger) benefits available from moving from the interim congestion pricing (after it has been operational for at least two years) to the OFA itself.

While, on the basis of the current evidence, a prima facie case can be made that the implementation of the OFA model would lead to net benefits, there are some additional considerations that the Commission believes should be noted.

First, OFA implements new pricing arrangements and, as such, could create new incentives for participants to ‘game’ the system in different ways. It would therefore be prudent to monitor generator bidding behaviour to observe if any new patterns emerged. This could inform any ‘fine tuning’ that the system may require at a later date.

Second, as discussed above, another useful addition to the model would be for AEMO to provide information to firm access applicants and the AER relating to required upgrades and indicative costs. By easing the information asymmetries faced by generators when dealing with monopoly TNSPs, such information provision could alleviate concerns regarding the use of market power. Using AEMO to provide information for firm access applicants and the AER would be consistent with the Commission’s recommended role for AEMO in other areas such as the RIT-T, and particularly new generator connections.

This would complement the additional elements of monopoly regulation envisaged by the AEMC as part of the OFA model. With these additions, and subject to the completion of a cost–benefit analysis, the Commission supports the OFA model in principle.

Recommendation 19.2

Provided that cost–benefit analyses show net benefits (including incremental net benefits in moving from short‑term congestion pricing), and once technical matters have been resolved, the Australian Energy Market Commission should commence implementation of the optional firm access package for generator access to the transmission network.

* It should operate for a period of at least 10 years.
* The Australian Energy Market Operator (AEMO) should provide information to applicants for firm access and the Australian Energy Regulator relating to the (long-term) upgrades required, and benchmark indicators of their cost.
* Optional firm access should be monitored by AEMO for its effects on network planning and performance and, in concert with the Australian Energy Regulator, changes in observed patterns of generator bidding behaviour. Monitoring results should be made public annually.

While implementation of OFA is a substantial exercise itself, it is not necessarily the end‑point for market reform in the NEM. Over the longer term, there may be grounds for more fundamental reform.

## 19.4 More fundamental reforms

### Nodal pricing — theory

OFA appears to provide an effective way of resolving perverse incentives that arise in the presence of congestion, but it does so by using the existing regional settlement method and essentially ‘retro-fitting’ side compensation payments. A more direct method of managing congestion would be to dispatch and pay generators according to their LMP, not a regional price. The price of electricity at different locations where electricity is injected or withdrawn from the network (‘nodes’) would differ (a model also referred to as ‘nodal pricing’), especially in the presence of congestion on particular lines.

In addition to exposing generators to the ‘true price’ (encompassing production, location and congestion costs) at their connection point, nodal markets also generally involve a system of financial transmission rights (FTRs), that operate in a similar manner to OFA rights (typically defined on either a point-to-point, or ‘flowgate’ basis). In effect, FTRs provide access to the local price at the ‘destination’ node, acting as a form of hedge between nodes. Importantly, these rights can be purchased, typically at auction, on a ‘directional’ basis (that is, ‘A to B’ is a separate right from ‘B to A’). The rights can be purchased by both users and producers. In the same way as firm access rights, the auction of FTRs could provide a market-driven signal for transmission investment from *both* supply and demand sides of the electricity market, aligning transmission investment with its value to users.

Several electricity markets around the world use such nodal pricing, but the exact model applied varies between markets. For example, both the Pennsylvania-New Jersey-Maryland (PJM) in the United States and the New Zealand electricity market use ‘full nodal pricing’ — that is, both generation and load are settled at nodal prices.[[30]](#footnote-30) Alternative models include ‘generator nodal pricing’ where generators are settled using granular locational–based pricing, but loads are settled using more aggregate prices (for example, prices for a zone or region, or a single price for the entire system). One example of this is the New York electricity market in the United States, where generators are settled on a ‘location-based’ marginal price (similar to LMPs), and loads are settled on a zonal basis, using a load-weighted average of the prices within their zone (Frontier Economics 2009, p. 39).

While the increased granularity of nodal pricing encourages more efficient dispatch (by removing incentives for behaviour such as disorderly bidding), it can in turn facilitate other forms of inefficient behaviour. In nodal markets, this typically manifests itself as more traditional uses of market power, with generators withholding supply in order to increase their LMP. This is one of the reasons why some nodal markets include measures designed to encourage levels of supply, while inhibiting the ability of generators to exercise market power. For example, the PJM market incorporates the following:

* An *offer cap* to prevent large spikes in prices. These are set at $1000 per MWh by the Federal Energy Regulatory Commission. (The presence of capacity markets in the United States is intended to provide a means for generators to recover fixed costs, while energy market returns recover variable costs. In contrast, in the Australian NEM, the high price cap in the energy market is intended to allow generators to recover both fixed and variable costs over time.)
* *Market power mitigation rules* designed to prevent the use of local (or time‑limited) market power. These rules entail capping of generators’ offers, typically applying a formula based on generator-specific cost-based schedules (Hogan 2012b). In some markets, the trigger for application of these rules has been refined over the years to concentrate on those generators and bids that would have a significant impact on the market (Frontier Economics 2009).

Despite the concerns of the structural presence of market power, there has been little evidence of the exercise of market power in the major nodal markets to date (Frontier Economics 2009 and Rose 2011). This suggests that the combination of capacity markets and mitigation rules has had some effect in limiting the ability of suppliers to take advantage of their positions of market power.

Nodal pricing is the subject of significant academic and regulatory analysis — more detail on the theory of nodal pricing, and particularly its application in a variety of markets can be found in Frontier Economics (2009) and NWRED (2011).

### Nodal pricing in Australia?

Nodal pricing in the NEM was proposed in a major review 10 years ago (Parer et al. 2002). However, it has not been adopted due to its complexity, perceived difficulties in implementation and potential increases in risk in financial markets. Perceived political difficulties with exposing customers within the same region of the NEM to different energy prices have also been a major obstacle (though governments could choose to ameliorate the impacts through transparent community service obligations). There have also been concerns that the ‘geography’ of the NEM is not as suited to nodal pricing as some other networks are. For example, PJM is a highly meshed network and, as such, there is potential for congestion on a single line to have wide‑reaching effects. In comparison, the NEM is a more ‘stringy’ (or radial) network where distance looms as a larger issue than congestion. While nodal pricing may have particular benefits for networks such as PJM, it would nonetheless provide benefits for the NEM, both in terms of dealing with congestion and properly accounting for location.

In the first interim report of the TFR, the AEMC contemplated an option for a form of nodal pricing that included a single national price for customers (box 19.7).

|  |
| --- |
| Box 19.7 The AEMC’s National Locational Marginal Pricing package |
| The first interim report of the Transmission Framework Review included the option of a ‘national locational marginal pricing’ (NLMP) package.  In this package, generators would be settled in the energy market using their locational marginal price (LMP). This component of the package would largely remove the incentive to disorderly bid, as generators would no longer be able to enter low bids yet receive the higher regional price.  Generators would then have the option of purchasing (at auction) fully firm financial transmission rights. These rights would provide firm access to a single, national trading hub. This hub would use a single ‘system marginal price’. Load (that is, users) would be settled at the system price, not using LMPs. This was intended to provide a deeper and more liquid energy trading market than the present regional system. More broadly, the package would remove the need for ‘regions’ in the market arrangements.  The AEMC envisaged the implementation of NLMP involving a single, national TNSP. This TNSP would initially auction the baseline transmission capacity, followed by auctions for incremental capacity. It would be exposed to incentives that encouraged the availability of the auctioned transmission capacity. This capacity would be made available by investing in the physical network to ensure that its capacity matched the amounts purchased at auction. |
| *Source*: AEMC (2011f). |
|  |
|  |

However, the AEMC’s proposed option was not supported by stakeholders in that review who noted that, among other things, a single national price for load would blunt any efficiency gains by rendering the demand side unresponsive to any localised price signals (AEMC 2012j, p. 122). In the second interim report, the AEMC decided against further consideration of the model. It stated that difficulties in creating the single TNSP (that it felt was a necessary component of the model), combined with the efficiency concerns of a single national price for load made the model a ‘disproportionate response’ (p. 123).

If full nodal pricing were to be implemented, the Commission acknowledges that differences in pricing between locations are likely to cause equity concerns. However, as noted elsewhere in this report (chapters 11 and 14), the Commission considers that such concerns should be dealt with by more transparent and targeted assistance for particular customer groups, rather than uniform (but not cost reflective) pricing. Doing so would alleviate distributional concerns, while preserving the efficiency gains available through (cost reflective) price signals. Providing information to consumers about the nature of the change, the benefits from it, and the options available to them would also be an important precursor to any implementation of nodal pricing.[[31]](#footnote-31)

The substantial difference between the current NEM model and nodal pricing has also raised concerns in the past about the degree of transition costs that could be incurred by moving to nodal pricing. Indeed, the introduction of nodal pricing would require careful establishment of new market infrastructure. This is a particular issue for the hedging markets, and one that must be considered alongside the auctioning of FTRs, a significant issue for the New Zealand market. The introduction of nodal pricing would also require consideration of governance issues, particularly if the market’s departure from a regional structure lends further weight to NEM-wide transmission planning.

While transition costs are a relevant consideration for judgments of reform, there are several well-known ways to minimise them by managing the transition process — general options include the pre-announcement of changes, and gradual phasing in of reform. However, given it is a significant shift from the status quo, and a matter of market design, adopting nodal pricing may not be conducive to phasing.

While phasing directly to nodal pricing may not be appropriate, the Commission considers that the OFA package represents a substantial transitional step towards implementing nodal pricing. It involves many of the same (or at least analogous) aspects to nodal pricing — including the calculation of LMPs, a concept of congestion pricing and firm access rights. Indeed, some have noted that the OFA model can be characterised as ‘a form of nodal pricing for a subset of generators’ (Biggar 2012, p. 2). Thus, allowing the OFA package to operate for a period of 10 years would allow the energy market to acclimatise to many of the complexities that have frustrated implementing nodal pricing in the past. Similarly, it could also allow hedging markets to adjust to the concept of different prices (for generators).

After that time, a cost–benefit analysis of the introduction of nodal pricing should be conducted, with a view to identifying any significant and insurmountable obstacles that would prevent its adoption. Such an analysis could also consider the exact form of nodal pricing involved, the structure of FTRs (particularly given the evolution of OFA requests) and any accompanying market infrastructure that would be required, such as capacity markets or the need for any specific market power controls. At this time, extensive community consultation would also be required.

Importantly, the review should consider if other, smaller, changes to the OFA package could achieve largely the same benefits as nodal pricing, with lower transition costs. Examples noted above include incorporating load (the demand side) and unscheduled generators into the OFA model, as well as the potential for any contestability in the provision of OFA to new transmission elements linking to an existing network such as an interconnector or a new load (for example, a mine).

Recommendation 19.3

After the optional firm access package has been operational for 10 years, a review should be conducted to consider whether the introduction of nodal pricing is warranted on cost–benefit grounds, or if other reforms (such as alterations to the optional firm access model) offer greater benefits. The review should have particular regard to the structure of the National Electricity Market at the time, the views of consumers and other stakeholders, and any remaining barriers to the introduction of nodal pricing.

### A timeline for reform

As discussed above, the Commission considers that there is the need, and scope, for substantial reform to the NEM, in relation to generators’ access to the transmission network and bidding in the spot market. While the reform required is substantial, there are benefits to participants from phasing in the reforms through a staged implementation process. The recommendations above discuss this process. The timeline for this process would be as follows:

* By the end of 2013: complete an initial cost–benefit analysis of the OFA model to confirm that detailed implementation planning should commence.
* Within two years (in 2015): implement a short-term congestion pricing mechanism, based on the SACP model.
* Over the next five years (2013–18): conduct extensive consultation on the detailed plan for the OFA model. Based on the detailed plan, and at least two years of operation of congestion pricing, conduct a more detailed cost–benefit analysis, including the incremental benefits of moving from congestion pricing to the OFA model. Provided this shows a positive net benefit, implement the OFA model (by 2018).
* Allow OFA to operate for 10 years.
* After this 10 year period, begin a review to determine if nodal pricing or other, more incremental, reforms are justified.
* Following the judgment of the review, take at least one year to design the details of any reform.
* Allow a transition period of at least two years if nodal pricing is recommended.

## 19.5 The hedging market

Spot market energy prices in the NEM are highly volatile. This means that any market participant that traded directly through the spot market would be exposed to a significant level of pricing risk. Participants in the NEM manage this risk either by trading in the hedging market (described in appendix C), or through vertical integration with retailers (creating ‘gentailers’). Electricity hedging is a key part of the efficient operation of the NEM, and questions of market design need to consider the impact on the efficiency of the hedging market. In particular, outcomes in the hedging market can affect actual energy flows including the level of interstate trade in electricity.

### Hedging markets are state-based

Participants in the hedging market enter contracts based on the NEM’s state‑based regional reference prices. This allows participants within a region to contract effectively because they are both exposed to the same spot market price. However, if a party wanted to contract with a party in another region of the NEM it would need to bear the risk associated with relative movements in the prices in different states, or alternatively, find a way to manage that risk (box 19.8).

One way to manage this risk is through settlement residue auctions (box 19.9) that allocate inter-regional settlement residues (IRSRs). IRSRs are a financial product that distributes the price residues that occur when electricity is transmitted across a regulated interconnector. However, IRSRs are a non-firm hedge, which means that if there is a large price separation between two regions and power does not flow through the interconnector, as can occur through disorderly bidding, there is no residue to distribute and the hedging strategy fails. As the AER noted:

… disorderly bidding has created the risk that SRAs [settlement residue auctions] are designed to manage, whilst simultaneously reducing the value of that risk management tool. … the reduction of firmness in SRA units imposes potential long term costs on market participants and end users. (2012t, p. 21)

While it is difficult to know how IRSRs are used by market participants, Anderson et al. (2007, p. 30) suggest that IRSRs are used primarily as speculative instruments, rather than as hedging instruments — contrary to the original intentions of policy makers. (This view was also echoed in comments by participants in this inquiry.)

|  |
| --- |
| Box 19.8 Understanding the risk of trading between regions |
| A standard hedging product, known as a contract for difference, allows market participants to determine prices in advance and remove the exposure to the spot market. Under such a contract, the generator and the retailer agree to a ‘strike’ price (shown as X below), which will ultimately be the terms they use for trade, even if the spot price (P) is different.  If the spot price is lower than X (which would expose a generator to losses without hedging), the generator would receive P from the wholesale market and X-P from the retailer, with a net price paid for power of X. If the spot price was above X, the retailer would buy power at P on the wholesale market (that is, would have an apparent exposure of -P), but would receive P-X so that the actual exposure would be –X. The payoff structure is represented below:   |  |  |  |  | | --- | --- | --- | --- | |  | Spot market exposure | hedging contract | Net exposure | | Generator | P | X – P | X | | Retailer | –P | P – X | –X |   However, when trading between regions, the spot price exposures are no longer the same. So, if a retailer (in region 2) buys a hedging contract from a generator in region 1, the payoff becomes:   |  |  |  |  | | --- | --- | --- | --- | |  | Spot market exposure | hedging contract | Net exposure | | Generator | P1 | X – P1 | X | | Retailer | –P2 | P1 – X | –X + (P1 – P2) |   (P1 – P2) is the risk in relative movement in regional reference prices and is a natural risk of trading between regions of the NEM.  (Continued next page) |
|  |
|  |

|  |
| --- |
| Box 19.9 Settlement residue auctions (continued) |
| When electricity flows across a regulated interconnector, loads and generators are settled at their regional price. This means that if electricity flows from a low price region to a high price region (as would usually be expected), the price paid to generators will be less than the price paid by loads. The difference between the two prices, multiplied by the level of flow across the interconnector and after adjusting for transmission losses, is the inter-regional settlement residue.  AEMO sells these residues in a quarterly auction, and the winners of the auction receive the rights to a share of the interregional settlement residues in the upcoming period. |
| *Source*: AEMO (2011e). |
|  |
|  |

The average payout of the settlement residue auction process corroborates this perspective. Were IRSRs used as an effective hedging instrument, buyers would be willing to pay a premium to manage risk (in the long term), just as with other insurance products. Accordingly, it could be expected that the receipts from buyers (that is, the auction revenues) should, over the long term, be greater than the settlement residues paid out by AEMO.[[32]](#footnote-32) However, the evidence does not appear to support this (table 19.2).

If firms do not use the IRSRs to manage the risk of trading electricity contracts across regional boundaries, they are left with two options. Either they trade across the border exposed to the interregional price separation risk, or they trade only within their state.[[33]](#footnote-33) Of these, the latter is more common, with retailers and generators trading derivative products with other market participants that operate in the same region of the NEM.

### Implications of a state-based hedge market

The inability for market participants to effectively trade between regions of the NEM, without being able to manage the risks well, may result in distorted incentives for new generators and large electricity consumers. It may also result in a lack of liquidity in parts of the NEM and may create market power.

Table 19.2 Historical results of settlement residue auctions

|  |  |  |  |
| --- | --- | --- | --- |
| Auction | Residue distributed | Auction proceeds | Payout rate |
|  | $ million | $ million | % |
| 2009 Q1 | 83.1 | 59.1 | 141 |
| 2009 Q2 | 83.0 | 15.6 | 531 |
| 2009 Q3 | 11.5 | 17.2 | 67 |
| 2009 Q4 | 145.7 | 28.0 | 520 |
| 2010 Q1 | 55.4 | 55.9 | 99 |
| 2010 Q2 | 13.9 | 16.3 | 85 |
| 2010 Q3 | 20.5 | 17.5 | 117 |
| 2010 Q4 | 18.3 | 32.1 | 57 |
| 2011 Q1 | 102.1 | 46.6 | 219 |
| 2011 Q2 | 6.6 | 17.6 | 37 |
| 2011 Q3 | 12.5 | 21.2 | 59 |
| 2011 Q4 | 16.4 | 29.2 | 56 |
| 2012 Q1 | 7.7 | 43.5 | 18 |
| 2012 Q2 | 9.5 | 16.9 | 57 |
| 2012 Q3 | 13.1 | 19.4 | 67 |
| **Total** | **599.3** | **436.1** | **137** |

*Source*: AEMO Auction Reports (AEMO website).

#### Incentives for generator location

The difficulty of trading hedging contracts across regions could distort the locational decisions of new generators and energy consumers. When a generation business chooses a location for a new generator, a key concern will be the availability of well-priced hedges. This consideration will make them more likely to enter a region in which there is more consumption than generation of electricity. This incentive will be in addition to the interplay of supply and demand for electricity. For example, consider a generator that was planning to enter the NEM near the New South Wales‑Victoria border. From an engineering perspective, it makes little difference on which side of the border they are placed. However, the new generator will look at whether it can trade in forward markets at a higher price in New South Wales or Victoria. A similar situation would occur with large electricity consumers, such as smelters, although access to the hedging market would usually be a lower priority for the locational choices of these parties.

These problems in the hedging market have the potential to equalise the level of electricity generation and consumption in each region of the NEM, as each new generator will favour a location in a region with less generation than consumption, and each new load will favour a region that has more generation. This would result in less interconnector construction and usage than might be efficient. It would also make it more difficult for a state to act as a net producer of electricity in the NEM (despite any potential natural cost advantages such as availability of cheap coal or gas resources) and reduce the benefits from efficient trade across the NEM.

The size of this impact is unclear. The different regions in the NEM are all relatively evenly matched between retail load and generation, which partly reflects history, but also suggests that the incentives described above could be strong. However, there are several other reasons that parties wish to build generation close to a load centre, such as avoiding transmission losses and ensuring a more reliable dispatch.

#### Less liquidity in the hedging market

Financial liquidity is measured as the amount of trade that occurs in a particular market. Liquidity is important in a market, as it gives market participants confidence that they will be able to enter and exit contracts in the future. This is particularly important for a new entrant retailer or generator that required some assurance that they would be able to enter hedging positions once they commenced operations.

Higher levels of liquidity also lower the difference between the buying and selling price (bid‑ask spreads) of instruments. Bid‑ask spreads are a cost of transacting in the market and lowering those spreads results in lower trading costs for market participants.

Some parties suggest that levels of liquidity in the electricity futures market are low, particularly in some regions of the NEM (D-Cypha Trade 2011). However, if the market for electricity hedging products were to become more national, this would allow people to trade across states, and create greater substitutability of contracts in different areas. This would increase the liquidity and improve the performance of the market.

#### Issues of market power

While generation and retailing are now regarded as workably competitive in most regions of the NEM, market power is not entirely absent in these parts of the electricity system. Market power could arise, for example, if there are barriers to entry for new generators posed by the large scale of cost-efficient generators and a requirement for high capacity utilisation (which may require the capacity to sell into several regional markets). Box 19.10 sets out some of the claimed forms and impacts of such market power.

|  |
| --- |
| Box 19.10 Market power in generation? |
| Residual market power in generation and gentailing could take several forms, although their importance is strongly contested by varying parties. The ACCC has scrutinised the privatisation of New South Wales generation assets (ACCC 2011), AGL’s purchase of a larger share of the Loy Yang power plant,[[34]](#footnote-34) and whether gentailers are offering power purchase agreements to renewable energy generators (Wroe 2012). The AEMC has also considered issues of market power with regard to Rule change proposals. The most recent example of this is the Major Energy Users proposal to restrict the bidding of dominant generators to $300/MWh. However, in its draft determination, the AEMC (2012o p.49) found insufficient evidence of any problem.  A simple case of market power would occur if a generator had the ability to push up prices in the spot market by withholding supply, and thereby attract more revenue. This would benefit any unhedged generator and adversely affect any unhedged retailer. However, any such market power would likely to be transient, since higher prices would attract entry by competing generators, and empirical analysis by the AEMC has not identified a significant problem (AEMC 2012o, p. i).  A slightly more subtle case of market power would arise if a generator were able to artificially create greater price volatility by withholding some generation capacity, or by bidding into the market at a high price. This might increase spot prices on those occasions, but it could also have an impact on the market for some types of hedging instruments, such as price caps. If that generator had some advantages in selling these instruments,[[35]](#footnote-35) such as a gas or hydro plant, they would acquire a return that would not be shared by other generators.  Competition benefits, which are the benefits from reducing market power, are also considered in the transmission planning and RIT-T processes.  The exercise of any market power by generators may have several efficiency costs:   * Inefficient merit order dispatch would occur if large low‑cost generators bidding high were dispatched after peaking generators. * Demand side responses may be used inefficiently as the cost of a demand response is typically high compared with the cost of generating energy. * Market power may limit the competitiveness of the retail market. Some consequences of this are found in chapter 12. * If market power results in high prices in a region where there is no shortage of supply, it may give incentives for new entrants where none are needed. |
|  |
|  |

Improving the performance of interconnectors and allowing more interstate competition, both in a physical sense and in the hedging market, would further limit the ability of market participants to exercise market power.

There are also grounds for action in one area of (possible) gentailer conduct to reduce market power. On first appearance, a gentailer has little incentive to exercise market power because high prices at the wholesale level hurt the retail side of their business. However, knowing when a price spike will occur in advance might, in theory, allow a generator to hedge out of their retail position. Any retail competitors will not know in advance when this might happen and would have to remain hedged against the risk at all times. This would give the gentailer a competitive advantage in the retail sector. This type of behaviour is difficult to detect, as hedging positions are commercial-in-confidence, an issue that has been of some concern in the United States (AEMC 2010b).

Accordingly, there could be some merit, from a regulatory perspective, in providing these hedging positions to the regulator retrospectively, perhaps 12 months after the event, and on a confidential basis. This could allow better examination of market power issues. The regulator could also use the information to publish (aggregated) summary data where this might help potential new entrants evaluate the risks and returns from entry into the generation and retail sectors. This could also have the added benefit of helping market modellers understand the incentives behind generator bids, which in turn could improve the accuracy of forecasting involved in the RIT-T process.

However, such an improvement in transparency would involve compliance costs on the businesses involved, and risks breaching genuinely confidential contracts. These costs would need to be weighed against the benefits of additional transparency before any transfer of information might be mandated.

Reforms in this area need to be seen in the broader context of ongoing reforms of the derivatives market, which were announced at the G20 summit held in Pittsburgh in 2009.[[36]](#footnote-36) These reforms, which were further developed in a consultation process undertaken by the Council of Financial Regulators, aim to increase the use of financial market infrastructure[[37]](#footnote-37) in the derivatives market (COFR 2012). While the main goal of this reform is to achieve financial market stability, the report noted that the reforms would also ‘help detect market abuse’ (p. 3). The report concluded that while there were significant benefits to financial market reforms, ‘in the first instance, industry-led solutions should be the preferred route to increasing the use of centralised infrastructure within the Australian OTC [over-the-counter] derivatives market’ (p. 2).

In the context of the Australian NEM, an industry-led movement to increase the use of a centralised clearing process would be beneficial, but to take full advantage of this resource, regulators must be provided with information, and make use of it.

### Options for reform

A more national hedging market would allow for improved risk pooling, enable an efficient spread of generation and load across the NEM and more competition in the generation and retail sectors. The best way to achieve this is to improve the effectiveness of IRSRs.

The AEMC’s OFA package includes the option to purchase firm interregional transmission rights. These rights would replace the existing IRSRs and could be used to hedge across regions, with two additional advantages. The access rights would be firmer than under the existing arrangements, making them more likely to be valuable in a hedging portfolio.[[38]](#footnote-38) In addition, the OFA structure nullifies incentives for disorderly bidding, and this would also make the hedging instrument more valuable. The OFA model would link the sale of these transmission rights to the incentives to build new interconnector projects.

Another reform option would be to alter settlement residue auctions so that the hedging instrument would pay the difference in the state prices regardless of the actual flow across the interconnector, which is ideal for the parties wishing to hedge. The Parer Review (Parer et al. 2002) and the Energy Reform Implementation Group (ERIG 2007) both suggested variations of this option.

However, the success of this approach would need to overcome several issues:

* As electricity does not always flow between regions when there is a price difference, there may be insufficient revenue to pay parties that purchased the transmission rights. This would require drawing additional funding from elsewhere in the network.
* This approach would become complicated if the parties that can cause counter price flows along a transmission line near some congestion (such as generators near a state border) were also bidding into the auction.

The OFA model is the superior option since it addresses many other issues apart from flaws in hedging arrangements. If OFA is not implemented, then there are grounds for amending settlement reside auctions as a second-best option.

1. Some other markets, such as the Pennsylvania-Jersey-Maryland (PJM) and New York markets in the United States, use separate capacity markets to ensure the long-term adequacy of power supply within their markets (Frontier Economics 2009). Such markets can include not only generation capacity, but also demand response and transmission investment. [↑](#footnote-ref-1)
2. Generators submit bids in a ‘schedule’ (supply Y1 MW at price P1, Y2 at price P2 and so on) in daily bids, submitted before 12.30 pm on the day before supply is needed. They may submit rebids until five minutes before dispatch. Rebids may change the volume, but not the price of electricity offered (AEMO 2010f). Nonetheless, with a sufficiently large number of price bands within a schedule (and with rebidding of volume in other bands to zero) rebidding of volumes, in effect, amounts to price changes. [↑](#footnote-ref-2)
3. The spot price used to settle market transactions is calculated for a 30-minute trading interval as the average of the six dispatch prices during the preceding 30 minutes. [↑](#footnote-ref-3)
4. There are other forms of market structure. *Nodal* markets involve many ‘nodes’ — the physical location, or grouping of locations — where power is entered or withdrawn from the network. Under nodal pricing, generators (and in some cases, customers) are settled at the price of their local node, and multiple nodal prices apply in a single market. At the other end of the spectrum, a single price could be applied across an entire network. [↑](#footnote-ref-4)
5. The Commission notes that disorderly bidding is a rational (and legal) response to incentives created through peculiarities of market structure. It uses the term in an analytical, not pejorative, sense. [↑](#footnote-ref-5)
6. Such clamping is not always successful, primarily due to generators’ stipulated ‘rates of change’ (ramp rates) which affect how quickly a generator’s output can be forced down (or up) and thus allow periods of time where interconnector flows can only be gradually, not instantly, reduced. Reforms to generator ramp rates are discussed later in this chapter. [↑](#footnote-ref-6)
7. Of course, generators maximising their return in the presence of temporary congestion is not a phenomenon unique to the NEM. In other markets, exercising transient market power can be manifested in different ways, for example, there is some evidence of generators withholding supply at times of import congestion in Norway (Mirza and Bergland 2012). [↑](#footnote-ref-7)
8. This figure is AEMO’s estimate of the ‘market impact’ of constraints, calculated by summing the values from the ‘marginal constraint cost’ re-run of the dispatch engine. This re-rerun removes any violating constraint equations (and marginally relaxes some others) to examine hypothetical market outcomes in the absence on congestion. It is a static measure of short-run production costs only. AEMO (2012i) only provides data from calendar years 2009 to 2011, limiting any ability to examine trends. This may not be an accurate measure of productive efficiency given that it takes generators bids as reflective of their short-run marginal costs. To some extent these bids would include instances of disorderly bidding, resulting in short run marginal costs being reported as -$1000 for those instances. [↑](#footnote-ref-8)
9. In contrast to the $22 million estimate, the $300 million revenue impact cited for one instance of disorderly bidding (AEMO 2010g) was calculated by holding the effect of the network constraint in place, but removing the rebidding of generators in response to it. This figure measures the market price effect, not production costs. [↑](#footnote-ref-9)
10. As noted in chapter 18, a Frontier Economics study conducted for the AEMC’s Congestion Management Review (AEMC 2008b) concluded that the (modelled) production costs due to disorderly bidding were only $8 million higher than the base (normal) case. Given production costs in the NEM at the time were $1.7 billion, this equated to a 0.47 per cent increase in costs. [↑](#footnote-ref-10)
11. Disorderly bidding can have several impacts on hedging, and thus on retail prices. First, instances of disorderly bidding can increase the volatility of returns in the market, potentially increasing the costs of managing risks. Second, by reducing or eliminating the effectiveness of inter-regional hedging options, it can reduce the liquidity in state-based markets. Third, these effects may flow through to reduced levels of retail competition. [↑](#footnote-ref-11)
12. As noted in chapter 3, various state governments still have significant ownership of both generation and networks. However, there is no direct evidence that they have taken advantage of this for the purposes relevant to these issues. [↑](#footnote-ref-12)
13. For example, package 2 of the AEMC’s first interim Transmission Framework Review divides generators’ returns into two components: energy payments settled at the marginal price at their local node, and a hedging element that divides the total *intra*-regional settlement residue between generators according to capacity, not dispatch. [↑](#footnote-ref-13)
14. These five packages were: a minor clarification to the status quo, a Shared Access Congestion Pricing (SACP) mechanism that would effectively impose congestion pricing at times of constraint, introducing transmission reliability standards for generators, an option to allow generators to purchase ‘firm’ access along transmission lines, and locational marginal pricing for generators (but not load). [↑](#footnote-ref-14)
15. For the purposes of implementing the OFA package, the AEMC examined specific pricing methods. They defined LRIC and long‑run marginal cost as different methods. In the technical appendix to the second interim TFR report (AEMC 2012n, pp. 42–3), the AEMC discussed the relationship between their definitions of the two measures (as well as ‘deep connection charging’). There, they note that their definition of long‑run marginal cost is a measure of the cost of transmission expansions that ignores ‘lumpiness’ in transmission investment. That is, if 347 MW of expansion is required, exactly 347 MW’s worth will be built. Their measure of LRIC takes account of the lumpiness inherent in transmission networks and would only allow for expansions to be built when the next substantial increment (say 500 MW) was required. As noted in chapter 11, lumpiness of investments is an appropriate factor to take account of when considering which method to use to calculate a measure of the (broader concept of) long‑run marginal cost. Therefore, the AEMC’s use of LRIC is consistent with the Commission’s preference for network pricing to be based on *a measure* of long‑run marginal cost. [↑](#footnote-ref-15)
16. In particular, the settlement mechanism has a similar effect to the shared access congestion pricing model (package 2 from the first interim TFR report). [↑](#footnote-ref-16)
17. That is, the difference between a generator’s ‘entitlement’ (or access right) and their ‘use’ (or quantity dispatched). [↑](#footnote-ref-17)
18. A ‘flowgate’ is a location on the shared network where congestion can occur (effectively, a transmission line between nodes). When congestion arises, these lines become bottlenecks in the transmission network. The AEMC (2012n, p. 99) define flowgate capacity as a combination of transmission line capacity and local demand (to the extent that it participates on a given flowgate). [↑](#footnote-ref-18)
19. To the extent that the generation market is not fully competitive, there is also the possibility of the reverse case — that is, generators passing on, at least partially, the costs to energy users through increased wholesale prices. Where this constitutes a misuse of market power, it is a matter of competition regulation, which to date has found it difficult to detect and prove such offences. Nonetheless, the congestion management aspects of the proposed OFA model should at least cut off disorderly bidding as one avenue for using market power. [↑](#footnote-ref-19)
20. The AEMC (2012n, p. 87) also noted that, given TNSPs should meet reliability requirements with least-cost builds, they are likely to build (or augment) lines to generators close to the RRN. This makes generators remote from the RRN much less likely to free ride than those close to it. [↑](#footnote-ref-20)
21. Depending on the weighted average cost of capital (chapter 5), TNSPs may have an incentive to set a low access price in order to have more assets ‘approved’ through firm access requests as firm access prices are only an estimate of project costs, and the actual costs are rolled into the regulatory asset base at the next revenue determination. While the TNSP would carry the risk of costs exceeding revenue in the regulatory period that they are built, they could make up for this through higher revenues in future periods (chapter 5). Other measures, such as correctly estimating the weighted average cost of capital, or reviewing the value of assets entered into the regulatory asset base, may be able to limit this incentive. [↑](#footnote-ref-21)
22. As access pricing reflects long‑run incremental costs, the ‘efficient price’ is likely to be a stylised forecast of an expansion plan, rather than an imminent and identifiable single project (as is the case with the RIT-T). [↑](#footnote-ref-22)
23. Such schedules would reflect stylised, indicative costs of a range of typical upgrades that would be required to give effect various levels of firm access requests (and also include components that varied with generator location). Of course, the *actual* individual price for any given firm access request would vary according to location and the particular combination of upgrades required. While not controlling the final access price, regulated schedules would act as both information to generators, and benchmarks that TNSPs would have to justify departures from. [↑](#footnote-ref-23)
24. ‘Super-firm’ access refers to a generator (of say 400 MW capacity) purchasing firm access rights at a level greater than its capacity (say 600 MW of firm access). As firm access rights are scaled back under certain adverse transmission conditions, purchasing ‘super-firm’ access improves the likelihood that a generator is able to dispatch its full capacity under a range of transmission conditions (AEMC 2012j, pp. 26‑8). [↑](#footnote-ref-24)
25. The AER also suggested (sub. DR109, p. 6) that AEMO review the constraint formulation guidelines in order to address large changes to interconnector flows at times of congestion. [↑](#footnote-ref-25)
26. Given the sporadic nature of disorderly bidding, basing allocations on a historical average, over a period of several years, could go some way to reducing the possibility of ‘locking in’ inefficient flows (particularly if known instances of disorderly bidding were removed from the data before the average was calculated). [↑](#footnote-ref-26)
27. As noted above, some transfers can, over time, take on characteristics of incentives where parties can expect and respond to them. Additionally, some transfers can be inconsistent with the NEO, that is, where they transfer away from consumers, and do not have any offsetting efficiency gains that would be in their long-term interests. [↑](#footnote-ref-27)
28. While not directly analogous to OFA, modelling the introduction of transferrable financial transmission rights into the NEM indicated small, but positive, net benefits related to improved location decisions by new generators (IES 2012). [↑](#footnote-ref-28)
29. While the nature of some of the costs and benefits from OFA may be difficult to quantify, methods such as those used to examine competition benefits in the RIT-T could be employed to examine the effects of changes in bidding behaviour. Further, international experience in conducting cost-benefit analyses for nodal pricing (for example in relation to the introduction of nodal pricing in Texas (CRAIRC 2008)) can be drawn on and adapted for use in modelling the NEM. [↑](#footnote-ref-29)
30. But these markets differ in other respects. For example, in the PJM market, ‘point-to-point’ FTRs were introduced when the market commenced (Frontier Economics 2009). In New Zealand, the market commenced in 1996 and FTRs have been the subject of much debate and analysis since then, without being implemented. Following a more recent consultation process, the New Zealand Electricity Authority (2012) expects the first auction of inter-island FTRs to be in early May 2013. [↑](#footnote-ref-30)
31. While the retailer would face cost-reflective nodal prices in the wholesale market, consistent with the Commission’s recommended approach in chapter 11, they could then develop a range of retail offerings for consumers (enabled by purchasing different bundles of FTRs). This could also allow different retailers to ‘specialise’ in different types of ‘package’ such as flat (sourced through FTRs that ensured financial access to baseload generators) or variable (FTRs to a range of generators) pricing. As the retailer faces cost-reflective prices in the nodal market, it will have an incentive to structure its overall basket of offerings in a manner that reflects the costs it faces. As such, while some customers may face flat tariffs, overall the summed consumption represented by the retailer should reflect costs. [↑](#footnote-ref-31)
32. A point made by AEMO (sub. 32, p. 26). [↑](#footnote-ref-32)
33. There is a third option where a firm can hedge using an interregional swap. This involves purchasing a short position in one region and a long position in another, and creates a ‘firm’ hedge. However, using this as part of a trading strategy across regions is effectively just hedging each individual trade in each region. [↑](#footnote-ref-33)
34. *Australian Gas Light Company v Australian Competition & Consumer Commission (No 3)* [2003] FCA 1525 [↑](#footnote-ref-34)
35. A discussion of the types of hedging contracts that different generators tend to trade can be found in appendix C. [↑](#footnote-ref-35)
36. Following this, the Australian Government announced in it will be introducing legislation to the Corporations Act to implement these commitments (Treasury 2012). [↑](#footnote-ref-36)
37. The term Financial Market Infrastructure refers to a centralised system used for the purposes of clearing, setting or recording financial transactions. [↑](#footnote-ref-37)
38. Though firmer than the current IRSRs, the inter-regional rights under the OFA package are not fully firm, as they would be ‘shaped back’ (proportionately scaled down) under certain circumstances. [↑](#footnote-ref-38)