Designing Transmission Rights to Facilitate Hedging

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Abstract In a liberalised wholesale electricity market risk-averse market participants need some form of financial instrument to offset the risks of spot price variation across locations and across time. Some liberalised wholesale electricity markets seek to facilitate transactions across separately-priced nodes by making available an instrument known as a Financial Transmission Right (or FTR). But FTRs are flawed as a hedging instrument. They do not necessarily make available the full set of funds required to allow market participants to hedge locational price differences. Furthermore, conventional FTRs, which are associated with a volume which is fixed in advance, are not useful for hedging transactions where the volume depends on market conditions at the time. This paper proposes introducing a new form of transmission right which mimics the operation of a 'cap' hedge contract. This transmission right can be combined into a portfolio which provides the natural backing for the price-dependent volume-varying hedge that most market participants require. Importantly, unlike conventional FTRs, the total payout obligation on these new transmission rights reflects the total social benefit of transmission service. We show how these transmission rights can be used to develop financial incentives on transmission network businesses and suggest a possible mechanism for decentralising transmission investment decisions. We consider that this new design of transmission rights offers promise as an approach for facilitating hedging and improving market outcomes in wholesale electricity markets.

Keywords: Financial Transmission Rights; CapFTRs; Basis risk.

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1 Introduction

Liberalised wholesale electricity markets typically involve spot prices for electricity which vary across locations and across time. Risk averse market participants (generators and retailers) seek to mitigate the risks they face by entering into financial arrangements known as hedge contracts. Contracts between generators and loads at the same physical netwok location can reduce the price risks to which each of these parties are exposed to the minimum feasible level (discussed further below). For generators this might involve the formation of a portfolio of swaps and caps, or other hedge contracts, which allow them to offload and/or mitigate the spot price risks to which they are faced.

The design of hedging arrangements is, however, complicated in the presence of nodal pricing (also known as locational marginal pricing). In a nodally-priced market generators and loads at different geographic locations buy and sell at prices which are not necessarily correlated and therefore are no longer effective counterparties in hedging. In the absence of effective mechanisms for hedging the locational price differences, generators and loads at separately-priced locations will not be able to mitigate the risks they face when trading with each other. The inability to effectively manage trading risks, introduces distortions to investment decisions (giving rise to a preference for co-location) and undermines of the value of the transmission network.[1] The availability of a range of suitable hedging instruments is therefore essential for efficient investment by risk-averse generators and loads. The design of mechanisms to facilitate the availability of hedge products is one of the fundamental issues confronting market designers. Ideally, in a nodally-priced market, a mechanism would be put in place to allow all generators and loads to have access to the same range of hedging instruments as they would if they were located at the same physical network location.

But what should be the form of that mechanism? The economics literature has focussed

[1] Hogan (1992) observes that "Whatever the practice of short-run usage pricing, it must be integrated with a policy for long-term access and contracts for firm transmission service ... [I]nvestors in long-lived, fixed facilities of the type and scale of major electric power plants will be reluctant to make commitments with no more than a promise of being allowed to participate in a short-term spot market for transmission services".

on a financial instrument known as a Financial Transmission Right or FTR.[2] FTRs come in two varieties: FTR *obligations* and FTR *options*. An FTR obligation from pricing node i to pricing node j, in the amount X, at a designated future time t, makes a payment equal to the spot price difference at that time multiplied by the volume of the FTR: $(P_{tj} - P_{ti})X$ where P_{ti} is the spot price at time t and node i. FTR options are similar except the payment is only made when the price difference is positive. The payout on an FTR option can be written: $(P_{tj} - P_{ti})X \; I(P_{tj} \geq P_{ti})$ where $I(\cdot)$ is the indicator function which takes the value one when the expression in brackets is true and zero otherwise.

Many liberalised wholesale electricity markets seek to facilitate hedging of transactions across separately-priced locations by making available FTR obligations. Unfortunately, however, FTR obligations are flawed as a hedging instrument, for two reasons: The first is that they do not necessarily make available the full congestion rents to the market. As a consequence, situations will arise where market participants are not able to reduce their risk to the minimum feasible level. The second, and more important, observation is that most generators produce a level of output which depends on the wholesale spot price. They therefore require a hedge contract with a volume which varies with the wholesale spot price in an identical manner. Conventional FTRs are associated with a fixed, pre-determined, price-independent volume. As a consequence, conventional FTRs cannot easily be used to hedge the risks faced by most generators.

Is there some alternative way of packaging the congestion rents which can more effectively hedge the risk of trading across separately-priced location? This paper contends that there is a straightforward way of packaging the congestion rents into a form of transmission right which allows market participants to make available the full range of hedging instruments required by generators and retailers.

[2]Financial Transmission Rights were first proposed as a tool to hedge the risk of locational price differences by Hogan (1992, 1993) and Harvey, Hogan and Pope (1996). See also the criticisms of Oren et al (1995) and Wu et al (1996). O'Neill et al (2003) extended the idea to 'Contingent' Transmission Rights which allow flexibility in the points of receipt or delivery of electricity. Sarkar and Khaparde (2008) is a useful recent survey of the theory of Financial Transmission Rights. See also Benjamin (2010) and the survey by Kristiansen (2005).

Specifically, this paper proposes a generalisation of the notion of a "cap" contract. It is shown below that, in the absence of transmission constraints, a conventional generator can construct a portfolio of cap contracts with an effective hedging volume that varies with the spot price in a way which mimics the profit-maximising output decision of that generator. This allows the generator to perfectly hedge the prive-volume risk it faces. This paper proposes generalising this approach to financial transmission rights. Specifically we propose making available a financial instrument which pays out the price difference between two nodes multiplied by a fixed volume, but only when the price in the "origination" node exceeds some pre-defined threshold. This transmission right has some of the properties of a 'cap' hedge contract and is referred to here as a *CapFTR*. The system operator, by making available a range of CapFTRs at each generation node allows traders to construct a portfolio which acts as the natural backing for the hedge contracts that generators and retailers require.

It turns out that this approach has important implications for the possible use of transmission rights in incentivising transmission investment and operation decisions. Historically, there has been a hope that the value of FTRs could be used as a signal of the need for transmission investment. It has even been suggested that it may be possible to decentralise transmission augmentation decisions by granting transmission entrepreneurs newly created FTRs in exchange for funding transmission upgrades.[3] However, to date it has not proven possible to link the change in the value of FTRs to the social value of a transmission augmentation. There have also been attempts to use FTRs as the basis of a performance incentive for network service providers, by for example, requiring the network service provider to compensate FTR holders in the event of a transmission outage. But research has shown that there is no necessary correlation betwen the price differences across a constrained line, the level of congestion rents, and the social benefit of relieving a transmission constraint. It is therefore not clear that the value of FTRs can be linked in a straightforward manner to performance incentives on network providers.

[3] See, for example, Hogan (2002).

The situation is, however, quite different for the form of transmission rights proposed in this paper. We show that a trader who constructs a portfolio of CapFTRs to hedge a transaction between generators and loads faces a payoff equal to the net social benefit from upgrading the transmission network on that transaction. In principle, therefore, the changes in the net payoff on the CapFTRs can be used to incentivise transmission operation and investment decisions. For example, in the event of a transmission outage, the transmission network provider could be made to "make whole" the CapFTR holders. Since the shortfall in funds on the CapFTRs is equal to the loss in social benefit, a scheme of this kind incentivises the transmission provider to make efficient reliability trade-off decisions. Similarly, it may be possible to decentralise transmission decisions. By allocating transmission rights in the manner proposed below, transmission entrepreneurs could receive the full social benefit associated with a transmission upgrade. This possibility is discussed further below.

This paper has five sections. The next section sets out the theory and develops the proposal in detail. Section 3 applies the proposal to a specific simple three-node network to highlight the main results. Section 4 considers how the proposed transmission rights might be used to guide transmission operational and augmentation decisions. Section 5 concludes and sets out a list of issues which will need to be explored in further work. The appendix sets out a summary of the notation and terminology used in the paper.

2 Analysis

Lets consider a simple wholesale electricity market. This electricity market will have, say, n generation nodes (labelled by i) and (for simplicity of presentation) one load node, labelled L. Without loss of generality each generator can be assumed to be located at its own node in the network. Losses will be ignored and we will assume the standard DC-load flow approximation.

In order to create a motivation for hedging we must introduce some uncertainty into the model. Lets assume that there are different uncertain future states of the market, which we will label s. The load in state s is assumed to be insensitive to the local spot price[4] and is given by L_s (MW), The wholesale spot price paid by retailers at the load node is P_{Ls} (\$/MWh). Similarly, the output of the generator at node i in state s is assumed to be G_{is} (MW) and the price paid for the output of the generator is P_{is} (\$/MWh). Since losses are ignored the overall energy balance constraint requires that the sum of generator output must match the load in every state s:

$$L_s = \sum_i G_{is}$$

The generator at node i is assumed to have a fixed and known cost function given by $C_i(G_{is})$ (\$/h)[5]. In much simplified economic analysis of electricity markets generators are assumed to have a simple constant variable cost c_i (\$/MWh) up to some capacity level K_i (MW). Here, however, we find that this assumption leads to some complexity, so we will not make this assumption at the outset. Rather we will assume that the each generator has a cost function with a strictly upward sloping marginal cost curve. Lets denote the marginal cost curve of the generator at node i as $c_i(G_{is}) = C_i'(G_{is})$. The assumption that the marginal cost curve is upward sloping implies that the inverse function $c_i^{-1}(\cdot)$ is well defined. The special case of constant variable cost will be treated as a limiting or extreme case.

2.1 Hedging for Generators

Lets consider how each generator hedges the risk that it faces. The raw or unhedged profit of the ith generator in state s is as follows:

$$\pi_{is}^G = P_{is}G_{is} - C_i(G_{is})$$

[4]This is without loss of generality since any demand-side response or load-shedding can be represented as a generator located at the load node.

[5]This assumption that the cost function is fixed and known rules out the case of intermittent and energy-constrained generation (such as hydro). The extension of this analysis to these cases is to be explored in further work.

Since the state of the market (and therefore the wholesale spot price) is unknown ex ante, this generator faces risk, reflected in the variability in its unhedged profit stream π_{is}^G. We will assume that this generator is risk averse and, other things equal, would prefer to exchange this risk for a fixed, certain profit stream. What is the nature of the financial contract which completely eliminates the risk faced by this generator?

Lets focus for a short time on the special case of the generator with constant variable cost. The raw or unhedged profit of this generator in state s is:

$$\pi_{is}^G = (P_{is} - c_i)G_{is}$$

What sort of financial contract would eliminate the risk faced by this generator? In order to completely eliminate the risk that this generator faces, the hedging instrument must have a payout equal to the generator's raw profit $(P_{is} - c_i)G_{is}$. This can be viewed as a hedging instrument which has a payout equal to the difference between the local spot price and the generators variable cost multiplied by the generator's output.

However if the generator were to obtain a hedging instrument with a payout dependent on its own output there would be a problem with incentives: the generator would no longer have an incentive to produce anything at all. This problem can be overcome by setting the volume in the hedging instrument in a manner which is *independent* of the actual output of the generator but which matches the variation of the generator's output with the wholesale spot price.

If we make the assumption that the wholesale spot market is sufficiently competitive, the profit maximising choice of output for a generator with constant variable cost as a function of the local spot price is well known: The generator produces nothing if the wholesale spot price is below its variable cost, produces at capacity if the wholesale spot price is above its variable cost, and is indifferent as to how much it produces when the wholesale spot price is equal to its variable cost. In mathematical notation the profit maximising choice of output of such a generator expressed as a function of the local wholesale spot price is as follows:

$$G_i^*(P_{is}) = \begin{cases} K_i & \text{if } P_{is} > c_i \\ 0 \leq G_i \leq K_i & \text{if } P_{is} = c_i \\ 0 & \text{otherwise.} \end{cases} \tag{1}$$

Using this observation we can construct a hedge contract which perfectly eliminates the risk faced by a constant-variable-cost generator in a competitive market. This hedge contract has a payout equal to $(P_{is} - c_i)G_i^*(P_{is})$ where $G_i^*(P)$ is given in equation (1).

This type of hedge contract is known as a *cap* contract. Cap contracts (including the special case known as a *swap* contract) account for the bulk of the transactions in the hedge market in the Australian National Electricity Market. A cap contract with a strike price c_i and a volume K_i is a financial contract which has the following payout when the wholesale spot price at the generator's node is P_{is}:

$$Cap_{is}(c_i, K_i) = \begin{cases} (P_{is} - c_i)K_i & \text{if } P_{is} > c_i \\ (P_{is} - c_i)G_{is} & \text{if } P_{is} = c_i \\ 0 & \text{otherwise.} \end{cases} \tag{2}$$

The middle case in this expression is redundant, but is included for reasons which will become clear in the discussion of the financial transmission right defined below. The payout on the cap contract can also be written as follows:

$$Cap_{is}(c_i, K_i) = (P_{is} - c_i)K_i I(P_{is} \geq c_i)$$

We have shown that when the strike price and volume in the cap contract are chosen to match the variable cost and capacity of a constant-variable-cost price-taking generator, a standard cap contract perfectly hedges the risk faced by that generator. However, what about the more general case of a generator with an upward-sloping marginal cost curve?

Using a straightforward result set out in the appendix, we observe that a generator can come arbitrarily close to eliminating all of the risk that it faces by purchasing a portfolio of cap contracts which are designed to replicate, arbitrarily closely, its marginal cost curve.

A price-taking generator (that is, a profit-maximising generator in a perfectly competitive market) chooses a level of output given by the inverse of the marginal cost curve: $G^*(P) = c^{-1}(P)$. Suppose we have a price-dependent hedge contract which pays out $H(P)$. The hedged profit of the generator is then $PG - C(G) - H(P)$. This hedged profit is independent of the wholesale spot price when the derivative with respect to the price is zero. This, in turn, implies that we must have $H'(P) = G^*(P)$ which implies that the theoretically optimal hedge contract is defined as follows:

$$H(P) = \int^{P} c^{-1}(p)dp$$

The result in the appendix shows that, given a set of hedge contracts with a range of strike prices $s_0, s_1, s_2, ...$, a price-taking generator with an upwardly-sloping marginal cost curve $c^{-1}(\cdot)$ can approximate the hedge contract which completely eliminates its risk $H(P)$ using a portfolio of cap contracts. The portfolio of cap contracts can be chosen to provide upper and lower bounds on the desired function, and approaches the desired function arbitrarily closely as the spacing of the strike prices $s_0, s_1, s_2, ...$ tends to zero.

$$\sum_i Cap(s_i, c^{-1}(s_i) - c^{-1}(s_{i-1})) \leq H(P) \leq \sum_i Cap(s_i, c^{-1}(s_{i+1}) - c^{-1}(s_i))$$

In summary, constant-variable cost price-taking generators can perfectly hedge their output using a single cap contract with a strike price equal to their variable cost. More generally, given the availability of a set of cap contracts with a range of strike prices, price-taking generators with an upward-sloping marginal cost curve can construct a portfolio which approximates the perfect hedge and that approximation can become arbitrarily close as the spacing in the range of strike prices tends to zero.

2.2 Hedging for Retailers

Lets turn now to briefly look at the hedging preferences of electricity retailers. Retailers are assumed to face an uncertain and non-price sensitive future demand for electricity. This uncertainty in demand gives rise to uncertainty in the wholesale spot price. In addition, retailers are assumed to on-sell the electricity they purchase on the wholesale market to small customers at a fixed downstream retail price-per-unit. Lets suppose that a retailer purchases electricity at the wholesale spot price and sells it to downstream customers at a fixed price $\overline{P}_L$. The raw or unhedged profit of that retailer in state s is therefore:

$$\pi^R_{Ls} = (\overline{P}_L - P_{Ls})L_s$$

As before, we will seek a hedging instrument which can completely eliminate the risk faced by this retailer. It is clear that this instrument must have the payout $(\overline{P}_L - P_{Ls})L_s$. We could define a hedging instrument which we might call a load-following-hedge (or LFH) which eliminates the risk faced by a retailer purchasing on the spot market and selling at a fixed price at the load node. It is clear that the load-following hedge for the fixed downstream price $\overline{P}_L$ and the uncertain load L_s must have the following payout $LFH(\overline{P}_L, L_s) = (\overline{P}_L - P_{Ls})L_s$. Such a hedge completely eliminates the risk face by the retailer.

2.3 The role of the trader

Lets introduce a new market participant which we will refer to as the *trader*. In practice, the trading role would typically be combined with either a generator, or a retailer, but this is not necessarily the case and for some purposes it is useful to think of this role as quite separate. The role of the trader will be to act as an intermediary between generators and retailers. The trader will seek to offer generators the cap contracts that they desire and retailers the load-following fixed-price contract that they desire, while taking all the remaining market risk on itself.

Traders cannot collectively eliminate all the market risk. There remain some risks even in a fully-integrated electricity industry. These risks arise from the overall variation in supply and demand conditions. The best that traders can achieve is to end up in a position where collectively they face the same risk that would be faced in a fully integrated electricity industry.[6] That is, the risks that would remain if the electricity industry were operated by a single integrated entity which owned all the retailers, generators, and received any other rents. The profit of this fully integrated wholesale electricity industry is as follows:

$$\pi_s^I = \overline{P}_L L_s - \sum_i C_i(G_{is})$$

In the case where there are no binding transmission constraints, all of the nodal prices are the same and equal to the price at the load node. In this case, traders can in principle sell cap contracts to the generators and fixed-price contracts to the loads (as described above) and will collectively be left with just the residual risk faced by an integrated wholesale electricity industry. In other words, in the case where there are no transmission constraints traders need no further sources of funds to provide all the hedge contracts that generators and loads require, while reducing the total risk faced to the minimum feasible level.

But in the presence of binding transmission constraints this is not the case. In this case we may ask: What additional flow of funds is required to allow all the traders in the market collectively to offer hedge contracts to both generators and retailers while not taking on any more risk than in an integrated industry?

Lets define the *congestion rent* to be the total surplus accruing to the system operator arising from nodal pricing. This is defined as follows:

$$CR = P_{Ls} L_s - \sum_i P_{is} G_{is}$$

[6] It is feasible to reduce risks further, but only by pushing risks upstream or downstream in the supply chain for example, by entering into contracts with suppliers of natural gas in which the supply price depends on the wholesale price for electricity, or by entering into contracts with loads in which the retail price depends on the wholesale price for electricity. These cases are set aside.

It turns out that the additional flow-of-funds required to allow traders to collectively offer hedge contracts to generators and retailers is just the congestion rent:

$$\pi_s^I - \pi_{Ls}^R - \sum_i \pi_{is}^G = P_{Ls}L_s - \sum_i P_{is}G_{is} = CR$$

It follows that any market design which makes use of nodal pricing to ration access to the transmission network should make available the full congestion rents to traders in the market.

In principle, in the absence of transactions cost, any market design which made available the congestion rents to traders would facilitate the availability of hedging instruments required by generators and retailers, since market participants could in principle repackage those funds in a manner which allowed them to trade the hedge contracts they require. In practice, however, the manner in which the congestion rents are packaged matters. It may simply be infeasible for traders to "piece together" the different pieces of the congestion rents and re-package them in a manner which facilitates hedging. This would be the case, for example, if the congestion rents were simply used to defray or reduce other transmission charges. In this case it would be all-but-impossible to recover these congestion rents into a meaningful source of funds to back up hedges to generators and loads.

But then, how should the congestion rents be packaged for traders? In the next section we look at how this is normally done - using FTRs, and why this approach is flawed.

2.4 Firm Financial Transmission Rights

Many liberalised wholesale markets make available an instrument known as a financial transmission right (FTR). These are also known as FTR obligations to distinguish them from FTR options. An FTR obligation between two locations on the network pays out a flow of funds equal to the difference in the nodal prices in those locations multiplied by a fixed quantity. An FTR of volume $\overline{F}_{ij}$ from node i to node j pays out the following amount in state s:

$$FTR_{ijs}(\overline{F}_{ij}) = (P_{js} - P_{is})\overline{F}_{ij}$$

There are two key questions for us to answer: First, do these FTRs collectively make available a flow of funds equal to the congestion rents? Second, do firm FTRs package the congestion rents in a manner which allows traders to easily provide the hedges that generators and loads require? As we will see, the answer to both questions is no.

It is a well known result that, under certain conditions, the collective payout obligation under the FTRs will not exceed the congestion rents (this is known as *revenue adequacy* and dates to Hogan, 1992). But there are circumstances where the payout obligation under the FTRs will fall short of the congestion rents. In such circumstances traders cannot collectively reduce the risks they face to the minimum.

Lets suppose that in some particular state of the market, the wholesale spot prices are given by (P_L, P_i) and the corresponding optimal dispatch is (L, G_i). For any other feasible dispatch (L', G_i') (i.e., which satisfies the energy balance constraint and the network flow constraints), the congestion rents earned at the same prices but under the alternative dispatch is always less than or equal to the congestion rent earned at the optimal dispatch.

$$CR(L', G_i') = P_L L' - P_i G_i' \leq P_L L - P_i G_i = CR(L, G_i)$$

This inequality is strict unless, on every network element which is operating at its maximum flow in the optimal dispatch, the flow in the alternative dispatch is also at the maximum.

In the simple wholesale market we are considering there are many generation loads and one load node. We will focus on the set of FTRs from the generation nodes to the load node. Given the complete set of point-to-point FTRs from each generation node to the load node (denoted $\overline{F}_{iL}$) it is straightforward to compute the corresponding implied dispatch:

$$L' = \sum \overline{F}_{iL} \text{ and } G_i' = \overline{F}_{iL}$$

The total payout obligation under these FTRs is then less than or equal to the congestion rents.

$$\sum_i FTR_{iLs}(\overline{F}_{iL}) = (P_{Ls} - P_{is})\overline{F}_{iL} = P_{Ls}L' - \sum_i P_{is}G'_i \leq P_{Ls}L - \sum_i P_{is}G_i = CR_s$$

Importantly, however, this inequality is strict unless, under the dispatch implied by the FTRs, the corresponding flow is at the maximum on every network element which is congested in actual dispatch. But, in general it will not be possible to satisfy this condition. The reason is that the actual dispatch is unknown in advance (at the time when the FTR volumes must be chosen). In the simple market we are considering there are only n distinct FTRs (one from each generation node to the load node), but there can be many more than n transmission links and therefore many more than n potentially binding network constraints in the actual dispatch. It will usually not be possible to choose a set of FTRs which simultaneously corresponds to a binding flow on every possible binding network constraint under all the possible ex post network flow outcomes. This is illustrated further in section 3 below.

Even more importantly, conventional FTRs do not allow traders to provide the hedges that generators and loads require for a much simpler reason: A firm FTR is a financial transmission right with a fixed volume. It is therefore a useful instrument for hedging transactions which feature a fixed volume of production and consumption. But how many generators enter into fixed volume transactions? A fixed-volume transaction might make some sense for a baseload generator which expects to produce a given amount at a certain time, independent of the market conditions at that time. But most generators in the wholesale market have an output which varies with the spot price. For example, mid-merit or peaking generators respond continuously to the wholesale prices, increasing or reducing their output in response to wholesale price changes. For these generators, if they are to effectively hedge the risks they face, the volume of the FTR must also vary with the spot price in a manner which mimics the production of the generator.

Conventional FTRs are only a useful instrument for hedging transactions with a fixed volume. Yet the output of most generators in the wholesale market varies with the wholesale spot price. This problem with FTRs is also noted by Sarkar and Khaparde (2008):

> "It can be seen that only a fixed physical transaction can be fully hedged by an obligation FTR alone. This transaction must be of the same MW amount as that of the obligation FTR and must be on the same path. That is why it is called a fixed hedge FTR."

But how then should we package the congestion rents to facilitate the hedges that generators and loads require?

2.5 The representative transaction

In order to explore the question of whether or not a particular mechanism for packaging the congestion rents results in a simple or straightforward backing of hedge contracts by traders we need to define a typical or representative market transaction by a trader and then ask how we should package the congestion rents to allow the trader to hedge that typical transaction. The idea is that the congestion rents should be packaged in such a way as to facilitate hedging of the most common or most typical transactions between generators and loads.

Lets define a *representative transaction* as follows. A representative transaction involving a subset of generators and a load is a commitment to purchase an amount of power g_{is} from the generator at node i in state s, and a commitment to sell the amount of power l_s to the load at the load node. It is assumed that this transaction satisfies the following conditions:

(a) the sum of the amount of electricity purchased from each generator matches the load in each state of the market;

$$l_s = \sum_i g_{is}$$

(b) the amount of electricity purchased from each generator is a fixed fraction of that generator's output:

$$g_{is} = \alpha_i G_{is}$$

where α_i is a constant specific to each generator.

This representative transaction might include, as special cases the following transactions:

- The purchase of a fixed volume of electricity by a fixed-volume load from a baseload generator (whose output does not vary);
- The purchase of the entire output of a generator to match a load whose output varies precisely in line with the output of a generator (this might occur where the addition of a specific load to the market was always matched one-for-one by the production from a specific generator); or
- The purchase of a share (say ten per cent) of the total output of all the generators in the market, to match the same share of load.

At the level of the market at as a whole, the collective output of all the generators in the market must match the load, so the transaction comprising the output of all the generators in the market and the total retail load is an example of a representative transaction.

The trader engaging in a representative transaction is assumed to provide to the generators and retailers the hedges they require. Specifically, the trader is assumed to provide a portfolio of cap contracts to each generator which completely eliminates the profit risk each generator faces. The trader is also assumed to provide the output to the retailer at a fixed price per unit of electricity which eliminates the risk faced by the retailer. (As emphasised earlier, the trader must retain some residual risk for itself).

The key question is how the congestion rents should be packaged so as to facilitate the trader in providing hedging transactions of this kind. First lets ask the question: what flow of funds does the trader require in order to back up these hedge commitments? As before, the flow of funds required is the difference between the profit faced by a perfectly integrated generator-and-load and the payout obligations under the various hedge contracts signed with the generator and retailer.

We saw before how a trader can write hedge contracts which arbitrarily closely approximate the profit functions of generators and loads. We can therefore assume that the payoff to the trader is just the sum of the raw or hedged profit of the generators and loads with which it transacts.

As before, we can ask what flow-of-funds is necessary to place this trader in the same position as if it were a vertically integrated (stand alone) entity providing just this transaction. Let π_s^I,π_s^R and π_{is}^G denote the pay-off to (respectively) an integrated entity providing this transaction, the hedge payout to the retailer, and the hedge pay-out to each generator in this representative transaction respectively. In a similar manner to the result we saw earlier, the cash-flow required to allow this trader to provide the required hedges to generators and loads, while taking on the minimum risk, has the form of a financial transmission right with a volume which depends on the output of each generator:

$$\pi_s^I - \pi_s^R - \sum_i \pi_{is}^G = P_{ls} l_s - \sum_i P_{is} g_{is} = \sum_i \alpha_i (P_{Ls} - P_{is}) G_{is}$$

From this result we can conclude that the trader would be able to obtain a natural backing for the hedge contracts it provides to generators and retailers for a representative transaction provided it is able to obtain a form of financial transmission right with a volume which varies precisely in line with the output of each generator.

But perhaps, then, we should just give to each generator a financial transmission right from its local node to the load node with a volume equal to its *own output*. In other words, perhaps we should just give each generator a payment equal to:

$$FTR_{iLs}(G_{is}) = (P_{Ls} - P_{is}) G_{is}$$

This is, in effect, precisely the current arrangements in the Australian National Electricity Market (NEM). In the current NEM market design all scheduled and unscheduled generators in a pricing region automatically receive a financial transmission right which pays out precisely the difference between the price at the regional reference node and the local nodal price, multiplied by the output of the generator.[7] The net effect is that each generator receives the price at the load node for its output:

$$\begin{aligned}
\pi_i^G(G_{is}) &= P_{is}G_{is} - C_i(G_{is}) + FTR_{iLs}(G_{is}) \\
&= P_{is}G_{is} - C_i(G_{is}) + (P_{Ls} - P_{is})G_{is} \\
&= P_{Ls}G_{is} - C_i(G_{is})
\end{aligned}$$

However, in an exact analogy with the discussion of cap contracts earlier, providing a generator with a hedging instrument which depends exactly on its own output will distort its incentives. As long as the price at the load node is above the variable cost of the generator, the generator has an incentive to attempt to increase the amount for which it is dispatched as much as possible. It can do this by offering its output to the market at a low price potentially as low as the offer price floor (which, in the NEM, is \$-1000/MWh). At the same time, if the price at the load node is below the variable cost of the generator, the generator would like to not be dispatched at all (no matter what the local nodal price happens to be). It can do this by offering its output to the market at a high price potentially as a high as the offer price ceiling (\$12,900/MWh). This distortion of offers is known in Australia as *disorderly bidding*. Disorderly bidding has been a problem in the NEM since the market began. It has led to multiple reviews and inquiries over the years. Disorderly bidding can be viewed as a direct consequence of the current approach to allocating the congestion rents in the NEM.

[7] The same is also true for loads located away from the regional reference node, but this complication need not concern us here. We will simply assume that all load is located at the regional reference node.

2.6 CapFTRs

But if allocating a financial transmission right which depends directly on a generators own output gives rise to distorted incentives, we can ask the question: is it possible to design the financial transmission rights in such a way which both facilitates hedging and does not distort the bidding behaviour of generators? As before, the solution is to set the volume in the hedge contract in a manner which is *independent* of the output of any one generator, while simultaneously matching the actual pattern of output of the generator. The idea here, as with the cap contract, is to make use of the observation that the output of each generator will vary with the local wholesale spot price. We therefore need to construct a financial transmission right with a volume which varies with the local spot price in a way which mimics the output of the underlying generator.

Lets start first with the special case of a constant-variable-cost generator operating in a competitive market. As noted earlier, the output of a constant-variable-cost price-taking generator is set out in equation (1). By the analogy with cap contracts (as defined in equation 2) we can define a CapFTR with a strike price c_i and a volume K_i from node i to the load node as having the payour $(P_{Ls} - P_{is})G_i^*(P_{is})$. In other words the payout on the CapFTR is as follows:

$$CapFTR_{iLs}(c_i, K_i) = \begin{cases} (P_{Ls} - P_{is})K_i & \text{if } P_{is} > c_i \\ (P_{Ls} - P_{is})G_{is} & \text{if } P_{is} = c_i \\ 0 & \text{otherwise.} \end{cases} \tag{3}$$

The only remaining potential source of difficulty is the choice of the volume of the CapFTR in the special case where the price at the local node is precisely equal to the variable cost of the generator (the middle case in equation 3 above). In this case the generator at this node is said to be the marginal generator. As emphasised above, if the volume of the CapFTR depended on the actual output of the marginal generator that generator would retain the incentives for distorted bidding. We must, instead set the volume of the CapFTR in this special case to some arbitrary value (between zero and the full CapFTR volume).

In the case of constant-variable-cost generators, this arbitrary assumption could pose a problem for hedging since the output of a particular generator might be required to vary to match load even though the local spot price is constant. The choice of an arbitrary, fixed volume for the CapFTR would eliminate the possibility for hedging the risk faced by a trader over the range where the local spot price is constant.

However, as noted at the outset, we have made the assumption that generators face a strictly upward sloping marginal cost curve. As a consequence, every change in output is associated with a change in price. In this case we can, as before, reduce the risk faced by a trader hedging a transaction between a generator and a load to the minimum using a portfolio of CapFTR contracts, shaped to match the output of the generator as a function of the local spot price.

We now need to show that we can approximate the required transmission right arbitrarily closely using only a portfolio of CapFTR contracts. As we have seen earlier, the required transmission right has a payout equal to:

$$FTR_{iLs}(G^*_{is})) = (P_{Ls} - P_{is})G^*_i(P_{is})$$

Given a set of strike prices $s_0, s_1, s_2, ...$, lets define $Q^L_i(P_{is}) = G^*_i(s_n)$ and $Q^H_i(P_{is}) = G^*_i(s_{n+1})$ where s_n is the largest strike price less than or equal to the spot price P_{is}. It follows that the profit-maximising choice of output for a generator lies between these values:

$$Q^L_i(P_{is}) \leq G^*_i(P_{is}) < Q^H_i(P_{is})$$

Hence it follows that (the sign of the inequality may be reversed when the local nodal price is above the strike price):

$$FTR_{iLs}(Q^L_i(P_{is})) \leq FTR_{iLs}(G^*_i(P_{is})) < FTR_{iLs}(Q^H_i(P_{is}))$$

It is straightforward to check that we can construct a portfolio of CapFTRs which provide the necessary bounds:

$$FTR_{iLs}(Q_i^L(P_{is})) = \sum_n CapFTR_{iLs}(s_n, c^{-1}(s_n) - c^{-1}(s_{n-1}))$$

$$FTR_{iLs}(Q_i^H(P_{is})) = \sum_n CapFTR_{iLs}(s_n, c^{-1}(s_{n+1}) - c^{-1}(s_n))$$

As the gap between the strike prices tends to zero, this approximation becomes arbitrarily close to the desired financial contract.

Furthermore, under the assumption that all generators behave competitive, the total payout of such CapFTRs across all generators at all nodes can approximate arbitrarily closely to the congestion rents (with the approximation becoming closer the smaller the gaps in the set of strike prices).

$$\begin{aligned}
\sum_i FTR_{iLs}(Q_i^L(P_{is})) &= \sum_i (P_{Ls} - P_{is}) Q^L(P_{is}) \\
&\leq \sum_i (P_{Ls} - P_{is}) G_i^*(P_{is}) = CR \\
&\leq \sum_i (P_{Ls} - P_{is}) Q_i^H(P_{is}) = \sum_i FTR_{iLs}(Q_i^H(P_{is}))
\end{aligned}$$

In other words, CapFTRs are a mechanism for packaging the congestion rents in a way which allows traders to make available the hedge contracts that generators and loads require. There is a full worked example showing how this might work in section 3 below.

2.7 The proposal

This paper proposes that, instead of making available firm Financial Transmission Rights, system or network operators should make available a portfolio of CapFTRs at each generation location.

It is proposed that both the range of strike prices and the volume of CapFTRs made available at each generation location should depend on the characteristics of the generation at that location. Specifically, both the range of strike prices and the volume of CapFTRs at each strike price should be chosen to allow traders to reflect the actual price-volume dependence of the output of each generator.

In the case of genuine baseload generators, the CapFTR may take the form of a conventional financial transmission right, with a volume reflecting the capacity of that generator. In the case of a peaking generator, the CapFTR should reflect the cost characteristics and capacity of that generator.

It is proposed that once the system or network operator has determined the portfolio of CapFTRs to be made available, it should auction these instruments to the highest bidder.

Slightly more formally, it is proposed that, at each generation node the system or network operator determine the strike prices and volumes to be made available (s_{in}, V_{in}). The system or network operator would then solicit bids from traders. Lets suppose that, at price p_{in}, the bid from trader t for the CapFTR with strike price s_{in} is $v_{int}(p_{in})$. The price for the corresponding CapFTR is simply the price which clears the market $\sum_t v_{int}(p_{in}) = V_{in}$.

The analysis above has assumed a single load node. However, the generalisation to multiple load nodes is straightforward. The addition of multiple load nodes increases the range of CapFTR instruments to be made available. As before, the system or network operator should choose the range of strike prices and volumes to be made available at each generation node. The system operator could then conduct an auction in which traders bid for the volume they require of a specific type of CapFTR from a specific generation node to a specific load node. The system operator would clear the market where the sum of the demand from a given generation node to each load node equalled the volume available.

3 A Three-Node Example Network

To illustrate how this proposal might work, it is useful to consider the following simple network example.

This network has three nodes labelled A, B and C. There are two generators at node A, labelled G1 and G2, and two generators at node B, labelled G3 and G4. There is also a generator at node B (corresponding to load shedding), labelled G5. All generators have a capacity of 500 MW. The variable cost of G1 is $10/MWh, G2 is $20/MWh, G3 is $50/MWh, G4 is $100/MWh, and G5 is $1000/MWh. The link between node A and B has a limit of 100 MW. The links between node A and node C and between B and C both have a limit of 650 MW.

The load is located at node C. The load at node C varies between 100 MW and 1400 MW in 100 MW steps. All of the transmission lines are assumed to have identical electrical impedance, so that one third of the power from A flows along the links A-B-C and two-third flows directly A-C (and similarly for the power from generators at node B).

Figure 1: Three-node Network Example

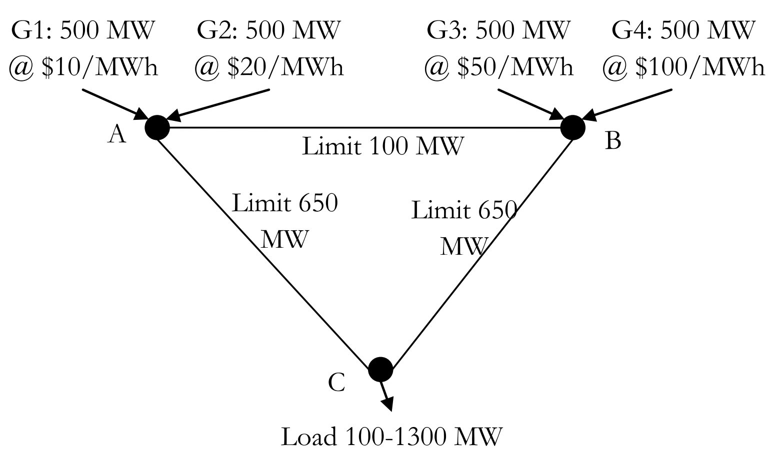


Table 1 shows the efficient pricing ($/MWh), dispatch (MW) and flow (MW) outcomes at each node and on each link under each of the possible states of the market. Table 1 also shows the congestion rent ($/h) and the total industry cash-flow ($/h) (assuming a fully integrated industry and assuming that the fixed retail price is $52/MWh).

Table 1: Efficient pricing, dispatch, and flow outcomes for the three-node example network

Load	Dispatch (MW)					Disp.	Flow (MW)		Price ($/MWh)			Cong.	Ind.
(MW)	G1	G2	G3	G4	G5	Cost	A→B	A→C	A	B	C	Rent	CF
100	100	0	0	0	0	1000	33.3	66.7	10	10	10	0	4200
200	200	0	0	0	0	2000	66.7	133.3	10	10	10	0	8400
300	300	0	0	0	0	3000	100.0	200.0	10	10	10	0	12600
400	350	0	50	0	0	6000	100.0	250.0	10	50	30	6000	14800
500	400	0	100	0	0	9000	100.0	300.0	10	50	30	6000	17000
600	450	0	150	0	0	12000	100.0	350.0	10	50	30	6000	19200
700	500	0	200	0	0	15000	100.0	400.0	10	50	30	6000	21400
800	500	50	250	0	0	18500	100.0	450.0	20	50	35	4500	23100
900	500	100	300	0	0	22000	100.0	500.0	20	50	35	4500	23100
1000	500	150	350	0	0	25500	100.0	550.0	20	50	35	4500	26500
1100	500	200	400	0	0	29000	100.0	600.0	20	50	35	4500	28200
1200	500	250	450	0	0	32500	100.0	650.0	20	50	35	4500	29900
1300	500	150	500	150	0	48000	0.0	650.0	20	100	180	156000	19600
1400	500	150	500	150	100	48000	0.0	650.0	20	100	1000	1.2 M	-75200

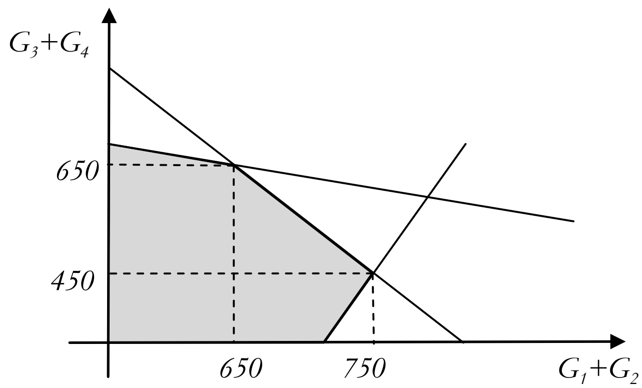
3.1 Hedging with firm FTRs

Now lets explore the question whether it is possible to provide the hedges that the generators and loads need with backing from firm FTRs. We saw earlier that this will only be possible if the total payout from the firm FTRs is equal to the congestion rent. So, the question for us to explore is whether it is possible to find a volume of FTRs from each generation node to the load node which yields a payout equal to the congestion rent.

We know from the previous analysis that this is only possible where the volume of the FTRs corresponds to a set of flows on the network which are equal to the flow limit whenever a constraint is binding. The following diagram illustrates the set of feasible flows on this network. Any pair of injections in the shaded area (when matched by a corresponding withdrawal at the load node) corresponds to a feasible net injection on this network.

The points on the boundary of this feasible set correspond to the points where one or more network flow constraints are binding. From the diagram we can see that there are two points where two constraints are binding simultaneously, corresponding to the injections (750, 450) and (650, 650). However, there are no locations where all three network flow constraints are simultaneously satisfied. We can therefore conclude that it is not possible to determine a pair of FTRs which yields a total payout equal to the congestion rents.

Figure 2: It is not possible to find a pair of FTRs which always yields a total payout equal to the Congestion Rent



This can be further illustrated in table 2, which shows the payout from two different possible combinations of FTRs: (750, 450) and (650, 650). As can be seen, the combination of a volume of 750 MW on A→C and 450 MW on B→C yields a payout which is equal to the congestion rents in all except states 13 and 14. The combination of 650 MW on both A→C and B→C yields a payout which equals the congestion rent in states 13 and 14 but not otherwise.

Table 2: No Pair of FTRs always yields a payout equal to the congestion rents

State	Load (MW)	Cong. Rents	A→C FTR(750)	B→C FTR(450)	Total	A→C FTR(650)	B→C FTR(650)	Total
1	100	0	0	0	0	0	0	0
2	200	0	0	0	0	0	0	0
3	300	0	0	0	0	0	0	0
4	400	6000	15000	-9000	6000	13000	-13000	0
5	500	6000	15000	-9000	6000	13000	-13000	0
6	600	6000	15000	-9000	6000	13000	-13000	0
7	700	6000	15000	-9000	6000	13000	-13000	0
8	800	4500	11250	-6750	4500	9750	-9750	0
9	900	4500	11250	-6750	4500	9750	-9750	0
10	1000	4500	11250	-6750	4500	9750	-9750	0
11	1100	4500	11250	-6750	4500	9750	-9750	0
12	1200	4500	11250	-6750	4500	9750	-9750	0
13	1300	156000	120000	36000	156000	104000	52000	156000
14	1400	1.2 M	735000	405000	1140000	637000	585000	1222000

3.2 Hedging using CapFTRs

Now consider the representative transaction consisting of the sale of the entire output of G1 to a load which varies exactly in line with the output of G1. The trader responsible for this transaction could then offer G1 a cap contract which perfectly hedges its risk, and the load a fixed-price contract which perfectly hedges its risk. The trader could then purchase a CapFTR against the price at node 1 with a strike price equal to \$10/MWh (the variable cost of G1) and a volume of 500 MW.[8]

As table 3 shows, with this cash-flow stream the trader is left in exactly the same position as he/she would be if this generation and load comprised the entire (integrated) electricity industry. In other words the CapFTR allows the trader to provide the hedging instruments that the generators and load desires.

Table 3: CapFTRs allow traders to form the hedging portfolios which they need

State	Load	Dispatch	Price (\$/MWh)			Trader Profit (\$/h)			Int.
	(MW)	G1	A	B	C	Raw	CapFTR	Net	CF
1	100	100	10	10	10	4200	0	4200	4200
2	200	200	10	10	10	8400	0	8400	8400
3	300	300	10	10	10	12600	0	12600	12600
4	350	350	10	50	30	7700	7000	14700	14700
5	400	400	10	50	30	8800	8000	16800	16800
6	450	450	10	50	30	9900	9000	18900	18900
7	500	500	10	50	30	11000	10000	21000	21000
8	500	500	20	50	35	13500	7500	21000	21000
9	500	500	20	50	35	13500	7500	21000	21000
10	500	500	20	50	35	13500	7500	21000	21000
11	500	500	20	50	35	13500	7500	21000	21000
12	500	500	20	50	35	13500	7500	21000	21000
13	500	500	20	100	180	-59000	80000	21000	21000
14	500	500	20	100	1000	-469000	490000	21000	21000

As a final example, lets consider the representative transaction which consists of selling one tenth of the output of all the generators in the market to a load (which must, of course, equal one tenth of the total load). The trader can back-up the hedging that generators and loads desire by obtaining a portfolio of CapFTRs consisting of one tenth of each of the

[8]Strictly speaking, the trader would have to purchase a portfolio of such contracts with slightly different strike prices to match the variation in the volume output of G1.

CapFTRs for each generator. The results are set out in table 4.

Table 4: The use of CapFTRs to hedge a transaction consisting of one tenth of the load

State	Load	Dispatch				Price ($/MWh)			Trader Profit ($/h)			Int.
	(MW)	G1	G2	G3	G4	A	B	C	Raw	CapFTR	Net	CF
1	100	100	0	0	0	10	10	10	420	0	420	420
2	200	200	0	0	0	10	10	10	840	0	840	840
3	300	300	0	0	0	10	10	10	1260	0	1260	1260
4	400	350	0	50	0	10	50	30	880	600	1480	1480
5	500	400	0	100	0	10	50	30	1100	600	1700	1700
6	600	450	0	150	0	10	50	30	1320	600	1920	1920
7	700	500	0	200	0	10	50	30	1540	600	2140	2140
8	800	500	50	250	0	20	50	35	1860	450	2310	2310
9	900	500	100	300	0	20	50	35	2030	450	2480	2480
10	1000	500	150	350	0	20	50	35	2200	450	2650	2650
11	1100	500	200	400	0	20	50	35	2370	450	2820	2820
12	1200	500	250	450	0	20	50	35	2540	450	2990	2990
13	1300	500	150	500	150	20	100	80	-13640	15600	1960	1960
14	1400	500	150	500	150	20	100	1000	-129720	122200	-7520	-7520

4 Transmission Augmentation

There is an important potential extension of this work to the theory of transmission investment.

One of the key objectives and achievements of the liberalisation of wholesale electricity markets was that it allowed for the decentralisation of generation operation and investment decisions. In a competitive market with effective price signals, profit-maximising generators can in principle be left to make their own decisions as to how much they will produce at each moment of the day. Furthermore, those price signals also provide a signal for investment in principle leading to the efficient amount, type, location, and timing of new investment. As Adam Smith emphasised, each generators private action is guided as if by an invisible hand to promote overall economically efficient outcomes.

Many theorists have sought to explore whether those same price signals could effectively guide transmission operation and investment decisions. Can, for example, nodal price differences be used as a guide for private, profit-maximising, transmission investment? Some of the enthusiasm for this possibility is captured by Joskow and Tirole (2005):

> [M]erchant investment's appeal is that it allows unfettered competition to govern investment in new transmission capacity, placing the risks of investment inefficiencies and cost overruns on investors rather than consumers, and bypassing planning and regulatory issues associated with a structure that relies on regulated monopoly transmission companies. In addition, in theory, it allows investment in new generating capacity in the constrained area to 'compete' with new transmission investment that reduces the import constraint. In this way, market driven transmission investment is an economist's dream, solving the problems associated with imperfect regulation of a 'natural monopoly' transmission company and aligning competitive transmission investments with the newly developed competition in the generation segment.

In principle, nodal price differences can be used as a signal for investment in DC transmission equipment[9], but DC assets are relatively high cost (except in some specific uses) and represent only a very small proportion of the total assets in use in electricity transmission networks around the world. In addition, problems of economies of scale limit the scope for competition and therefore the potential benefits of relying on so-called merchant transmission investment in DC assets for all except a few situations.

There has been a significant strand of thinking exploring the scope for private investment in AC transmission assets through the awarding of financial transmission rights. However that literature has highlighted several problems.[10] The payout on financial transmission rights (either individually or collectively) does not reflect the overall social benefit from augmenting the transmission network. As a result private transmission investment decisions

[9]Brunekreeft (2004) argues that the scope for private investment in the transmission grid is limited to DC (controllable flows) links.

[10]See Bushnell and Stoft (1996a,b; 1997). They showed that FTRs can be allocated in a way which eliminates the incentive to carry out a socially-detrimental grid expansion. But this is still a long way from designing a system which rewards socially-beneficial grid expansion.

(motivated by the desire to acquire FTRs) will not in general result in efficient transmission investment decisions. Joskow and Tirole (2005) conclude:

> Unfortunately, the optimality of the market driven approach depends on a number of strong assumptions and conditions that are likely to be inconsistent with the actual attributes of transmission investments and the operation of wholesale markets in practice. ... As a practical matter it is appears to be unlikely that we can rely primarily on competitive merchant investment to provide efficient investments in transmission infrastructure necessary to support efficient competitive wholesale power markets.

However, the situation is different in the market framework proposed in this paper. Under the proposal set out here traders are assumed to be able to create a portfolio of hedge contracts which perfectly maps the profit function of generators and retailers and use a portfolio of transmission rights to perfectly back those hedge contracts, so as to leave the trader in the same position as it would be in if it were a vertically integrated firm providing just the electricity in the underlying transaction.

But a vertically-integrated firm faces the full social cost of any network changes. Therefore, in principle, any change in the transmission network such as an augmentation should be reflected in a change in the payout of traders in a way which perfectly reflects the change in the social cost. This has important implications for transmission operation and investment decisions. For example, it suggests that there might be potential to decentralise transmission augmentation decisions. Traders might be required to individually or collectively agree to pay for an augmentation to the transmission network before it goes ahead. Traders could propose augmentations and seek to negotiate a coalition willing to fund it. Similarly, it seems theoretically possible to design incentives for transmission operators based on the social cost of their actions, by requiring transmission operators to compensate traders for lost revenue as a consequence of actions taken (or not taken) by the transmission operator.

The key idea here is that, unlike previous frameworks based around firm FTRs, the payout to traders correctly reflects the social cost of changes in the transmission network and therefore is potentially a useful signal for a range of operation and investment decisions

5 Conclusions

In designing a wholesale electricity market with nodal pricing, policymakers should seek to package the congestion rents in a manner which allows traders to make available the full range of hedge contracts to generators and retailers. A necessary condition is that the full congestion rents must be made available to traders. But this is not a sufficient condition. The congestion rents must be packaged in a manner which allows those traders to easily provide hedges for the transactions which generators and retailers desire. To achieve this, we suggest that the congestion rents should be packaged in a manner which allows traders to obtain a financial transmission right whose volume varies with the spot price at a node.

Many overseas markets make available firm financial transmission rights. But firm FTRs do not necessarily make the full congestion rents available to the market. The conventional theory only proves that the total payout of the FTRs is less than or equal to the congestion rents. But, in many cases the inequality will be strict the payout on the FTRs will be less than the congestion rents.

Even more importantly, the volume of these transmission rights does not vary with the local wholesale spot price. Therefore these rights cannot be used to provide hedges for generators whose output varies with the local spot price. Such variability is, of course, a key inherent feature of real-world power markets. Relatively few generators and very few loads face a volume of production and consumption which is fixed over time. Despite their use in some overseas markets, it is not clear that firm FTRs are a useful way to package the congestion rents.

This paper proposes that consideration be given to introducing a new form of financial transmission right which incorporates some of the properties of a cap hedge contract. It is shown that this financial transmission right, known as a CapFTR, allows for straightforward backing of hedge contracts associated with a wide class of transactions between generators and loads. This approach offers promise for better meeting the needs of the market participants and therefore facilitating the move to full nodal pricing in the NEM. There remain many questions to be answered. For example further work is needed to explore how the analysis applies to (a) intermittent or energy constrained generators; (b) network and generation outages; and (c) situations of market power. Nevertheless, it is suggested that this line of thinking offers promise for better integration of transmission services with generation operation and investment in liberalised wholesale electricity markets.

6 Appendix

We make use of the following result:

Lemma 1 *Given a set of strictly increasing strike prices* $s_0 = x_0, s_1, s_2, ...,$ *the integral*

$$\int_{x_0}^{x} f(s)ds$$

where $f(s)$ *is a strictly increasing function, is bounded above and below by the following portfolio of cap contracts:*

$$\sum_i Cap(s_i, f(s_i) - f(s_{i-1})) \leq \int_{x_0}^{x} f(s)ds \leq \sum_i Cap(s_i, f(s_{i+1}) - f(s_i))$$

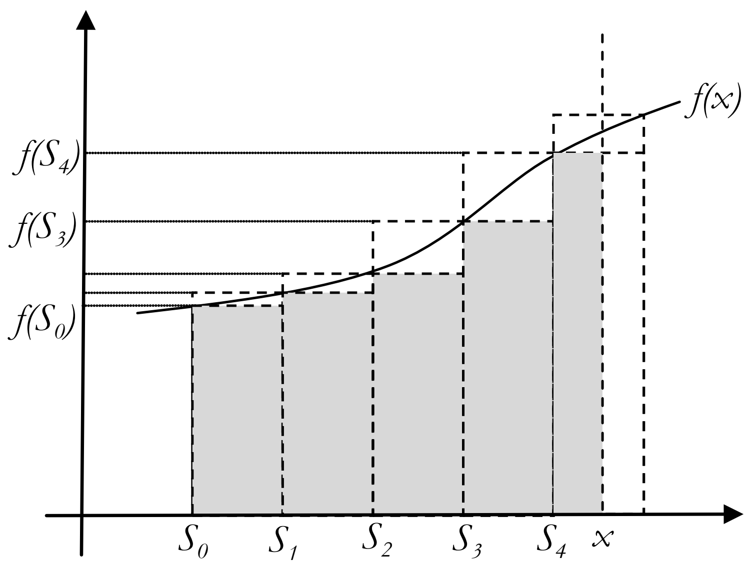
And moreover, this approximation becomes arbitrarily close as the distance between adjacent strike prices tends to zero.

Proof. Suppose we have a positive, strictly increasing function $f(x)$. We would like to find an approximation to the indefinite integral:

$$\int_{x_0}^{x} f(s)ds$$

Lets choose a finite set of values $s_0 = x_0, s_1, s_2, \ldots$. Without loss of generality we can choose $f(s_0) = 0$. As the following figure shows, we can place an upper and lower bound on the integral of the function:

Figure 3: Placing bounds on a continuous function with a step function



The upper and lower bounds are as follows:

$$\sum_i (x - s_i)(f(s_i) - f(s_{i-1}))I(x \geq s_i) \leq \int_{x_0}^{x} f(s)ds \leq \sum_i (x - s_i)(f(s_{i+1}) - f(s_i))I(x \geq s_i)$$

We can write this as follows:

$$\sum_i Cap(s_i, f(s_i) - f(s_{i-1})) \leq \int_{x_0}^{x} f(s)ds \leq \sum_i Cap(s_i, f(s_{i+1}) - f(s_i))$$

These bounds become arbitrarily close as the spacing in the set of values becomes increasingly small.

■

Table 5: Nomenclature

i	index of generator nodes
L	load node
s	index of future states of the market (representing different demand levels)
G_{is}	output of generator at node i in state s (MW)
L_s	demand at the load node in state s (MW)
P_{is}, P_{ls}	wholesale spot price at node i and at the load node in state s (\$/MWh)
$C_i(G)$	cost of production for generator i, when producing at rate G (\$/h)
$c_i(G)$	marginal cost of production for generator i when producing at rate G (\$/MWh)
$\overline{P}_L$	fixed retail price for electricity (\$/MWh)
π^G_{is}	raw (unhedged) profit of generator at node i in state s (\$/h)
π^R_{Ls}	raw (unhedged) profit of retailer located at the load node in state s (\$/h)
π^I_s	raw (unhedged) profit of a hypothetical integrated firm generating electricity at generation nodes and selling at the load node in state s (\$/h)
$G^*_i(P)$	profit-maximising output for price-taking generator at node i as a function of price P (MW)
$Cap_{is}(c, V)$	payout on a cap contract with a strike price c and a volume V referenced to the price at node i in state s (\$/h)
CR	congestion rent (also known as the merchandising surplus) (\$/h)
$FTR_{ijs}(V)$	payout on a financial transmission right from node i to node j with volume V in state s (\$/h)
l_s, g_{is}	consumption (at the load node) and generation at node i in state s in a representative transaction (MW)

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