A FRAMEWORK FOR ANALYSING TRANSMISSION POLICIES IN THE LIGHT OF CLIMATE CHANGE POLICIES

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I. Introduction

The Australian government is implementing "significant new policies to address the risks of future climate change that will directly affect behaviour and investment in gas and electricity markets".[2] These new policies include the introduction of a Carbon Pollution Reduction Scheme (CPRS) and an expanded national Renewable Energy Target (RET). It is expected that such policies will have a material impact on the operation of and investment in the Australian electricity industry. The Ministerial Council on Energy has asked the AEMC to review the resilience of the current energy market frameworks in the light of these major new policy measures.

This paper is designed to contribute to that process. Specifically the purpose of this paper is to set out a framework within which the full set of policies related to the efficient operation of and investment in a liberalised electricity market can be articulated and categorised, and the linkages and inter-relationships been those policies clarified.

This paper is broadly divided into two parts. The first part sets out a possible framework for thinking about transmission and generation policies. This section argues that the full set of relevant policies can be usefully grouped into three headings or categories, although with various linkages between the three sets of policies, as set out below. This section is deliberately intended to be slightly more abstract – potentially applying to any liberalised electricity market around the world, although examples from the NEM are used to illustrate the main points.

The second part of this paper applies the framework to the NEM, to identify issues that may arise as a result of the climate change policies mentioned above, to set out how those issues fits within the overall framework, and to show how those issues, and the various proposals for addressing those issues, relate to one another. Some of these issues are analysed in more detail than others. Some comments are made on the relative merits of some of the proposals for addressing these issues. But the primary purpose of this paper is not to analyse these issues or to discuss the pros and cons of various proposals. Rather the primary purpose of this paper is to set out a framework within which the issues can be ordered, and the linkages between them assessed and understood. This paper aims to be broad in its inclusion of issues, rather than deep in its analysis of specific issues.

Because the subject matter of this paper is broad, this paper is rather long, but I hope not too long.

[2] AEMC (2008), page i.

II. Background

As noted above, the MCE has asked the AEMC to review the resilience of the current energy market frameworks in the light of climate change policies. The AEMC released its "First Interim Report" in this review in December 2008.

The "First Interim Report" identified concerns that the existing arrangements may not, in the future, deliver both efficient short-term operational decisions and efficient longer term "co-optimized" investment and location decisions by the generation and transmission sectors. Specifically, the AEMC raises concerns that the proposed climate change policies may:

- Have an impact on overall system reliability due to a mis-match in the timing of a large increase in the amount of new generation capacity (primarily gas-fired generation and wind generation) and the retirement of some existing generation capacity.[3]

- Lead to a large (and potentially inefficient) need to upgrade the gas and/or electricity transmission networks due to the intermittency of new wind generation capacity and its propensity to locate in remote areas.[4]

- Increase the volatility (and weather dependence) of electricity spot prices, increasing the demand for ancillary services, and increasing the frequency of opportunities for the exercise of significant market power.[5]

- Increase congestion on the transmission network – including both inter-regional and intra-regional congestion.[6]

The first interim report also notes:

> "While historic congestion costs in the NEM have been relatively low, the implementation of the CPRS and expanded RET will test this. These policies will shift the location of generation over time quite profoundly, as coal-fired generation is replaced with gas-fired generation, and as renewable generators connect in new parts of the network".[7]

The report explains further:

> - "The CPRS and expanded RET will accelerate and alter patterns of investment in generation capacity over time, and the value of this investment will be very high. … the consequential investment costs on supporting network infrastructure will also be high.
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> - Any weakness in the incentives for efficient investment and location decisions could increase the materiality of network congestion with significant implications for total costs to consumers. Hence, factors that might have been immaterial historically might be material concerns in the context of the CPRS and expanded RET. The

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[3] AEMC (2008), issue A2, page 17.

[4] AEMC (2008), issue A5, page 34.

[5] AEMC (2008), issue A4, page 28.

[6] AEMC (2008), issue A6, page 42.

[7] AEMC (2008), page 43.

absence of robust charging arrangements for transmission investment to support greater inter-regional trade has already been identified in this context; and

- In a more rapidly changing environment, the costs of managing the risks associated with congestion might be heightened, and the allocation of risks (and the tools available for managing it) might not be adequate."[8]

Similar concerns of a possible conflict between climate change objectives and transmission pricing policies have arisen in other countries implementing major new climate change policies. For example, in the case of the UK, Castelnuovo et al (2008) note that several market players seem convinced that the UK will not meet its renewable target of 10.4% of electricity supply by 2010 (and double that by 2020)[9] unless significant new wind generation capacity is built in remote Scottish locations. But these locations are precisely those most disadvantaged by the current UK transmission pricing methodology:

> "This 'Scottish plan' appears threatened in the short term by the only form of locational signals currently in place, i.e., zonal use of system charges and in the long-term, potentially, by further types of spatial prices (e.g., zonal charges for transmission losses). Moreover, Ofgem, the British energy regulator, is concerned that the location of renewable generation in Scotland is inefficient and argues that if charging arrangements provide appropriate locational signals, then generators will face incentives to build capacity where networks need little or no reinforcement, i.e., much less in Scotland and more in England and Wales".[10]

Objectives of Transmission Policies

At the outset it is useful to set out the broad objectives of the policies that are the subject of this paper. The overall objective for the electricity industry, as stated in the National Electricity Law, is efficient operation of, and investment in, the electricity industry for the long-term interests of electricity consumers[11]. This overall objective can, in turn, be separated into shorter-term operational objectives and longer-term investment objectives, although, as we will see, there remain important interactions between the policies for pursuing short-term operational objectives and the policies addressing longer-term investment objectives.

Since transmission is both a substitute for and a complement for generation, achieving these short-term and long-term objectives requires closely coordinated or "co-optimised" action by both the generation and transmission sectors.[12] Traditionally, this coordination was achieved

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[8] AEMC (2008), page 43. The report also notes: "The consensus amongst stakeholders was that the introduction of new generation plant, largely driven by the expanded RET, would cause more congestion on the network. … ESIPC noted that not only was South Australia experiencing an increase in network congestion from wind plant investments, but that the congestion was having a market impact". AEMC (2008), page 44.

[9] See UK Department of Trade and Industry, 2003, *Our energy future – creating a low carbon economy*, page 12.

[10] Similarly, Brunekreeft, Neuhoff and Newbery (2005, page 73.) note: "Wind power in particular creates new flow patterns across grids, which were primarily designed to provide secure supplies to moderately self-sufficient countries and are not optimally designed and controlled to handle these and other market-driven patterns".

[11] National Electricity Law, clause 7.

[12] Furthermore, since gas transmission is a substitute for electricity transmission, efficient operation and investment decisions in both the gas and electricity industries requires closely coordinated or "co-optimised" action by both the gas and electricity transmission sectors.

through vertical integration – combining transmission and generation in the same firm. But this is no longer possible in the NEM. As Sauma and Oren (2006) observe:

> "Under the integrated monopoly structure, planning and investment in generation and transmission, as well as operating procedures, were, at least in theory, closely coordinated through an integrated resource planning (IRP) process that accounted for the complementarity and substitutability between the available resources in meeting reliability and economic objectives. The vertical separation of the generation and transmission sectors has resulted in a new operations and planning paradigm where IRP is no longer a viable alternative."[13]

In a liberalised electricity market, such as the NEM, where generation and transmission are under separate ownership, that coordination must take place through other mechanisms – such as price signalling, contractual arrangements, and explicit coordination rules and processes.

The objective of efficient short-term operational decisions can be further broken down into key component objectives such as the objectives of producing, at each point in time, the overall output at least cost (the efficient dispatch decision), with each plant producing at an appropriate level of technical efficiency, using the appropriate available plant (the unit commitment decision), with appropriate maintenance practices, and appropriate rationing of scarce resources (such as hydro storage). As already noted, to achieve these objectives these decisions will need to be coordinated or "co-optimised" with the operation of the transmission sector, including the extent of transmission losses, the real-time representation of transmission constraints, the control of load shedding, and the procurement of ancillary services.

There are corresponding objectives for the operational decisions of consumers of electricity – including that, at each point in time, electricity is consumed by those who value it most highly, and is used efficiently. In this paper I will primarily refer to efficiency objectives for the generation sector; this should be taken as referring to efficiency in both generation and consumption of electricity.

Similarly, the broad objective of efficient investment can be broken down into key subsidiary objectives such as efficient decisions regarding where, when and by how much to expand generating capacity, using which technologies, and what fuels, the number of units to install, and the size of each unit, what ramping capability to provide, what ancillary services capability to provide, and when to shutdown existing generating plant.

As before, these decisions must be closely coordinated with investment decisions in the transmission sector, including decisions regarding where, when and by how much to expand transmission capacity to achieve an overall efficient (least cost) transmission expansion path taking into account possible future evolving demand and supply scenarios. As noted above, this coordination must take place through either (a) arms-length price signals; (b) contractual arrangements; or (c) explicit coordination rules and processes.

[13] Sauma and Oren (2006), page 359.

II. A Framework for Organising Transmission Policies

This section sets out an approach to categorising and organising the full set of policies for promoting efficient short-term operational decisions and longer-term efficient investment decisions in by both the transmission sector and its upstream and downstream customers – generators and loads.[14]

The proposed approach divides the full set of policies into three groups:

(a) Policies for promoting efficient short-term operational decisions by generators and loads;

(b) Policies for promoting longer-term efficient investment and location decisions by generators and loads;

(c) Policies for promoting efficient operational and investment decisions by the transmission sector.

Transmission pricing versus other transmission policies

As we will see, the primary mechanism for achieving coordination between generation and transmission in a vertically-separated electricity industry is through *price* signals. A primary focus of the policies below is therefore the quality of the price signals to generators and loads. Brunekreeft et al (2005) write:

> "The transmission network is a natural monopoly whose charges must be regulated. In an unbundled industry in which generators and consumers react to market signals the structure of network charges will have a potentially significant impact on network use and its development. It will affect the locational choices of new generation (and of energy intensive users) as well as influencing the bidding behaviour of generators, and the willingness of neighbouring electricity markets to trade and cooperate. Clearly, then, setting these charges at the right level is critical for ensuring the efficient use and development of the network and the wider electricity market. It is also one of the most challenging and difficult problems facing regulators. Ideally the structure of network charges should encourage:
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> - The efficient short-run use of the network (dispatch order and congestion management);
> - Efficient investment in expanding the network;
> - Efficient signals to guide investment decisions by generation and load (where and at what scale to locate and with what choice of technology – baseload, peaking etc.);
> - Fairness and political feasibility; and
> - Cost recovery".[15]

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[14] This paper puts aside issues specific to the distribution sector.

[15] Brunekreeft et al (2005). Green (1997, page 178) lists the following six principles "which should be followed when designing electricity transmission prices". The prices should: "1. promote the efficient day-to-day operation of the bulk power market; 2. signal locational advantages for investment in generation and demand; 3. signal the need for investment in the transmission system; 4. compensate the owners of existing transmission assets; 5. be simple and transparent; and 6. be politically implementable".

At one level, the design of transmission pricing policies can be viewed as merely the application of principles of efficient monopoly pricing. Principles that are familiar from the theory of monopoly pricing in other sectors have direct application to the theory of transmission pricing. In particular, the value of marginal cost pricing, two-part tariffs, price discrimination, and Ramsey pricing, all have direct parallels in setting transmission charges.

In the case of transmission charges, the short-run "price" for the use of transmission services is reflected in differences in the short-run spot price for electricity across different locations. As we will see, short-run marginal cost pricing of transmission is primarily a matter of ensuring that those locational price differences precisely reflect the short-run marginal cost of transmission services between any two points.

However, as is well known from other industries, in the presence of economies of scale and scope, marginal cost pricing alone may not recover sufficient revenue to cover the total costs incurred. This additional revenue could be raised through a "two-part" charging structure, with a fixed (monthly or annual) charge for transmission services independent of the volume of electricity injected or withdrawn. Ideally this fixed charge would not distort the behaviour of transmission customers. Where a distortion to behaviour is inevitable, traditional pricing theory suggests that some form of Ramsey-Boiteux pricing should be considered, with higher charges on customers who are least responsive to those higher charges. Again, at one level, the design of efficient transmission network tariffs can be largely viewed as an application of the principles of efficient monopoly pricing.

However, it should be emphasised that efficient coordination between generation and transmission is more than just a matter of getting the prices right. Other relevant policies include policies regarding incentives for improving the quality and quantity of transmission services, incentives for the efficient procurement of ancillary services, and policies regarding longer-term transmission augmentation and investment decisions. The full set of relevant policies will also include the governance arrangements on transmission network operators, the system operator, and transmission planner(s).[16]. These other policies are emphasised further below.

2.1 Policies for efficient short-term operational decisions by generators and loads

Achieving the objective of efficient short-term operational decisions requires efficient decisions regarding the mix of generation plant to use, efficient use of inputs, efficient maintenance practices, efficient start-up and shut-down decisions, and so on. In a liberalised electricity market such as the NEM, almost all of these short-term operational decisions are delegated to independent profit-maximising generating entities. The primary tool for achieving these short-term operational efficiency objectives is the short-term spot price for electricity. Therefore, achieving the efficient short-term operational objectives noted above is primarily a matter of "getting the prices right" in the short-run.[17]

In fact, if generators (and loads) face a time-varying spatially-differentiated price which reflects, at every point in time and every location on the network the marginal value to the network of an additional unit of electricity injected at that point (or, equivalently, the marginal cost of an additional unit withdrawn from the network), profit-maximising generators and loads will make efficient short-term operational decisions. That is, overall the total electricity demand will be at the efficient level, and that demand will be met in the lowest-cost manner given the available generation, the physical limits of those generators, and the losses and physical limits of the transmission network at that point in time.

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[16] This includes ensuring voltage levels and frequencies are within tolerances, possibly through the procurement of voltage support (reactive power) services as and when necessary.

[17] The focus in this section is on getting the price signals right. However, as noted in the previous section, the full set of policies will typically include contractual arrangements and other rules and licence conditions.

Put simply, if generators and loads face the "correct" price at their location at each point in time they will be induced to make efficient short-run operational decisions. The correct price is the marginal value of an additional unit of electrical energy at that location given the demand and supply conditions and the physical losses and constraints on the network at that point in time.[18]

Moreover, if the following conditions hold:

(a) if each generator (and load) is allowed to offer its output to the market at a schedule of price/quantity combinations of its choosing, and if each generator (and load) is dispatched for a quantity and paid a price (at the margin) which lies on that schedule; and

(b) if the dispatch of each generator (and load) and the price at each location is determined through a centralised dispatch process which accurately reflects the losses on the transmission network and accurately takes into account the physical limits of the transmission network at that point in time; and

(c) if there is adequate competition between generators at each location on the network,

Then, each generator and load has an incentive to offer its output at a price reflecting its true marginal cost of production (or marginal value of consumption). As a result, at all points in time, the spot price at each location will be equal to the marginal value of an additional unit of electricity at that location, thereby inducing efficient operational decisions, as noted above.

In other words, in a liberalised electricity market such as the NEM, achieving the short-term efficient operational objectives set out above is primarily a matter of improving the short-term marginal price signals. In turn, improving the short-term marginal price signals is primarily a matter of addressing the conditions set out above – that is, ensuring that generators face the correct price at the margin; improving the accuracy of the representation of the physical network in the dispatch process; and improving competition.

It is worth emphasising that achieving efficient short-term operational decisions by a generator only requires that the generator face the correct price *at the margin*. For example, a generator might be paid a price of $35/MWh for its first 1000 MW of output, but then might face the local spot price of electricity for the remainder. Such a generator would retain incentives for efficient short-term operational decisions. For example, if the local spot price was $100/MWh and the generator's output was 1010 MW, the generator would receive $35,000+$1,000=$36,000 for each hour that it produced. Similarly, if the generator's output was only 990 MW, the generator would receive $35,000-$1,000=$34,000. Since this generator receives an extra $100 for increasing output by one unit (or loses $100 in revenue for reducing output by one unit), it faces the correct spot price *at the margin*.

Mis-pricing and residue allocations

As we explore further in section III of this paper, as in many liberalised electricity markets, various design decisions in the NEM depart from a theoretically perfect market. These market "imperfections" may become more significant in the light of the climate change policies.

In particular, as discussed in more detail in section III, as in several overseas electricity markets, the NEM dispatch process does not compute a different price at each distinct node on the

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[18] In addition, as emphasised further below, in order to make efficient inter-temporal decisions, such as unit commitment decisions, or efficient use of scarce resources such as hydro storage, generators and loads must have access to accurate forecasts of future prices, which may require a degree of transparency in the market.

network. Instead, in the NEM, nodes are grouped into "regions". Under the current NEM rules a generator does not receive the correct locational marginal price (or "nodal price") for its output at its own location but instead receives the price at a single node in the region, known as the regional reference node. As discussed in the AEMC's Congestion Management Review, and as summarised in section III, when the local nodal price for a generator is different from the regional reference price, the generator has an incentive to distort the price at which it offers its output to the dispatch process, giving rise to an inefficient short-term dispatch outcome, potential reliability issues, and other undesirable market outcomes, such as negative inter-regional settlement residues (which reduce the usefulness of the inter-regional settlement residues as a hedging device).

When the local nodal price for a generator differs from the regional reference price[19] the generator is said to be "mis-priced". A mis-priced generator can be either "constrained-on" or "constrained-off". A constrained-on generator has an incentive to pretend to the dispatch process to be unavailable, to be very high-cost, or to be unable to increase output. This results in other higher-cost generation being forced to increase its output or, where there is no other generation available, load must be shed, with implications for reliability. A constrained-off generator, on the other hand, has an incentive to pretend to be very low cost, or unable to reduce output. This results in other, higher-cost generation being forced to reduce their output, reducing the efficiency of the dispatch process.

This problem of mis-pricing (and constrained-on/constrained-off generators) potentially arises in any liberalised electricity market with a policy of uniform, zonal, or regional pricing. Most markets with uniform, zonal, or regional pricing control the incentives on generators to distort their offers through various forms of "side payments" to the generators. These side payments effectively ensure that generators face the correct price at the margin. The side payments might be made by the transmission network operator (the TNSP), or by the market operator itself.

For example, if a generator is dispatched for the amount Q_i, and paid the price P^{RRN}, at its location when the true marginal value of electricity at its location is P_i, the constrained-on/constrained-off payment would take the form $k+(P_i-P^{RRN})Q_i$ where *k* is an arbitrary constant. A payment of this form ensures that the generator receives additional revenue of P_i for each additional unit of output.

Charles Rivers' CSC/CSP proposal is one such form of constrained-on/constrained-off payment. In that mechanism the payment takes the form $(P_i-P^{RRN})(Q_i-\overline{Q})$ where $\overline{Q}$ is an arbitrarily-defined "entitlement". Under this mechanism the generator effectively receive the regional reference price P^{RRN} on the share $\overline{Q}$ of its output and the correct locational marginal price P_i on the remainder $(Q_i-\overline{Q})$. Importantly, the generator receives the price P_i at the margin and has the correct incentive to offer its output at its true marginal cost (provided there is effective competition between generators).

The different forms of these constrained-on/constrained-off payments differ primarily in (a) how the "entitlement" is defined; and (b) who pays. For example, one approach is to define the entitlement as "the level to which the generator would have been dispatched on its offer curve if it was just paid the regional reference price".[20]

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[19] Putting losses to one side.

[20] One drawback of this approach is that it creates an incentive for the generator to distort the shape of its offer curve so as to maximise the side-payments. However, as long as there is effective competition

As to the question of who pays, this could be either the system operator, or the transmission network service provider. For example, generators might be promised financial compensation from a TNSP if they were unable to be dispatched for their desired amount at a particular time. Long-term arrangements of this kind could, in principle, fully insulate a generator from both short-term maintenance practices, and longer-term changes in the network or the location decisions of other generators. Designing such compensation arrangements may not be entirely straightforward – in particular it may be difficult to ascertain precisely how much a generator would-have-been dispatched for in the absence of a particular transmission outage, particular if the outage changes the behaviour of other generators at the time, and particularly if the physical capability of the generating unit in question at that time is itself uncertain.

Side payments of this kind improve the incentives for short-run operational decisions by generators. However, depending on how the payments are allocated to generators, they are likely to distort longer-term investment/locational decisions.[21] For example, a key question is whether or not generators locating in constrained-off regions would receive any "entitlement" or "share" of the residues. If so, generators would have inefficiently large incentives to locate in these regions. This increases the importance of other, offsetting, locational signals.

In summary, achieving efficient short-run operational decisions is, in part, a matter of ensuring that generators face the correct price for their output. This can be achieved through either (a) some form of nodal or locational marginal pricing; or, alternatively, (b) through some form of uniform, zonal, or regional pricing, coupled with side-payments to generators and loads which ensure that the generator (or load) faces the correct price at the margin.

In addition to these "pricing" policies for improving the efficiency of short-run operational decisions, it is worth noting:

(a) since the efficiency of some short-term operational decisions (such as the unit commitment decision) depend not just on present spot prices but also on forecast future spot prices, the efficiency of short-run operational decisions can be promoted by improving the *quality of price forecasts*; and

(b) since, in practice, it is not possible to operate a literally instantaneous spot market, any real electricity market relies on access to "balancing" and "raise" or "lower" services for the time between successive spot price determinations. The efficiency of short-run operational decisions depends not just on spot prices but also on the *prices for ancillary services* including, potentially, markets for inertia or reactive power.

These issues are discussed further below:

Price forecasts

As noted above, many short-term operational decisions rely not just on the instantaneous spot price, but also on forecasts of the spot price in the future. For example, decisions as to whether or not to incur start-up costs (the "unit commitment decision"), decisions as to the efficient use of a scarce input (such as the efficient use of hydro storage), or decisions as to the optimal timing

generators do not have an incentive to distort their offer curve in the vicinity of the local price at which they are dispatched.

[21] These arrangements would not distort investment/locational decisions if the allocation of the residues did not depend on any actions of the generator.

of maintenance all, to an extent, depend on forecasts of future locational spot prices.[22] Therefore the efficiency of short-term operational decisions can be improved through policies to improve the quality of forecasts of future price.

The quality of future price forecasts depends, in turn, on the quality of information on future demand, supply, and network conditions. The quality of short-term operational decisions can therefore be improved through, for example, sharing of information on, say:

- The timing and nature of planned network outages (or other network changes);
- The timing and nature of planned generator outages (or new generation capacity coming on-line);
- Future demand forecasts (including the effects of demand-side management or non-scheduled embedded generation).

As the capacity of weather-dependent generation in the network increases it will also be of critical importance to improve the quality of forecasts of weather-related factors such as wind, sunlight, and wave heights (and therefore, indirectly, of wind, solar, and wave generation) as a tool to improve the quality of forecast prices. This point is strongly emphasised in a 2005 report by ESIPC:

> "Without excellent wind generation forecasting we should expect a significant deterioration in the forward demand forecasts which are vital for other generators trying to make efficient plant commitment decisions".[23]

Ancillary services

As noted above, due to transactions costs it is simply not possible to operate a literally instantaneous spot market in electricity. Instead, the electricity spot price is only determined at fixed intervals – in the case of the NEM, at five minute intervals[24]. In order to maintain the balance between supply and demand in the period between spot price determinations, liberalised electricity markets also make use of markets for "contingent" services, that are only drawn on as needed. In the NEM these services are known as frequency control ancillary services (FCAS). The "instantaneous" balancing service is known in the NEM as "regulation". The other FCAS services can be drawn on to increase or decrease the overall power supply in slightly longer time periods (six seconds, sixty seconds, five minutes).

In addition, maintaining voltage levels over long-distance transmission networks requires the creation or absorption of "reactive power" which often must be sourced locally.

The achievement of the objective of efficient short-run operational decisions by generators and loads requires, in addition to efficient spot prices for electrical energy, efficient prices for these ancillary services. This requires, in turn, that there are markets (or at least, prices) established for these services, that the efficient quantity is purchased, that the market clears at the efficient price, and that the markets are competitive. As we will see in the next section, certain concerns have

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[22] For example, the maintenance decisions of transmission networks and generators should, to an extent, be coordinated. If a transmission spur to a generator is taken out of service, the generator cannot, in any case, produce and may be able to use the time productively carrying out maintenance of its own.

[23] ESIPC (2005), page 25. As mentioned in AEMC (2008), NEMMCO has received a grant from the Australian Government to develop the Australian Wind Energy Forecasting System (AWEFS).

[24] To my knowledge, the NEM uses one of the shortest dispatch intervals in liberalised markets around the world.

been raised about future demands on ancillary service markets with a substantial increase in wind generation.

Summary

To summarise, the full set of policies for promoting efficient short-term operational decisions by generators and loads are as follows:

(a) policies for ensuring the efficiency of the short-run energy dispatch outcome, including policies for:

    (i) ensuring that each generator (and load) faces, at the margin, a price that reflects the marginal value of electricity at its location (including both losses and the cost of transmission congestion), or equivalently, policies regarding the allocation of the residues created through locational marginal pricing of the transmission network;

    (ii) improving the accuracy of the representation of losses or physical transmission limits in the centralised dispatch process;

    (iii) improving competition between generators (and/or loads) at each location on the network; and

(b) policies for improving the quality of price forecasts, including by:

    (i) improving the quality of information available about future supply (including planned generator outage), demand (including output of non-scheduled and weather dependent generation), and network (including planned transmission outage) conditions; and

    (ii) improving the reliability of the short-term and medium-term price forecasts produced by the dispatch process.

(c) policies for ensuring efficiency in the provision of ancillary services including policies for:

    (a) ensuring that generators and loads face the correct price at the margin for ancillary services;

    (b) ensuring that the correct quantity of ancillary services is purchased; and

    (c) ensuring that the markets for ancillary services (where markets are used) are competitive.

2.2 Policies for efficient longer-term investment decisions by generators and loads

Let's now look at the range of policies for promoting efficient longer-term investment and location decisions in the generation sector (and, to a lesser extent, the investment and location decisions of large loads). As we saw earlier, this includes decisions regarding where, when, and by how much to expand generation capacity, as well as decisions regarding the nature of the investment itself (peaking versus baseload, fuel used, ancillary service capability, etc).

Generation entrepreneurs make investment decisions based on forecast future profit opportunities. The profit of a generator depends on its revenue and its costs. The forecast revenue, in turn, depends on the shape of the spot price-duration curve at its prospective location[25], together with any side payments or allocations of residues mentioned above. A generator's forecast revenue also depends on its hedging policy and the current price of any hedge contracts the generator may wish to sell at its prospective location. The generator's forecast cost depends on fuel (or wind) availability and cost at its prospective location, together with the price-duration curve (which determines how often and for how long the generator will be producing), the cost and availability of other key inputs (such as cooling water), the cost of any related services (such as the cost of extending the transmission network to the prospective location of the generator), and any charges for the use of the transmission network.

Although differences in the costs of certain inputs, such as labour or land, provide an incentive for a generator to locate in one location over another, provided the price of those inputs is determined in competitive markets, we can assume (at least as a first approximation) that these prices reflect the marginal cost of those inputs. Any resulting locational incentive is therefore economically efficient and can be put to one side.[26] We focus here on those locational incentives created by transmission policies.

In addition, of course, certain generation location decisions will be primarily driven by availability of certain fuels such as access to coal, wind, wave, or solar energy. For these types of generators, the locational variation in access to energy sources may greatly exceed even the largest feasible locational differentiation in transmission charges. For some prospective investments, locational differentials in transmission charges will have little or no impact on location decisions, and therefore little or no impact on overall economic efficiency. On the other hand, locational differentials in transmission charges will always have an impact "at the margin" when comparing two prospective sites which are equivalent in all other respects. In addition, differentials in transmission charges are likely to have a larger impact on the location decisions of more "footloose" generation such as gas-fired generation.

As we noted earlier, the primary instrument we have for inducing efficient generator location decisions is the design of the structure of charges for the use of the transmission network. As we will see, these charges should broadly reflect the costs of using the transmission network – in the short-run and the long-run, in the sense discussed below. However, this assumes that substitutes for the electricity transmission – and, in particular, the gas transmission network – are themselves efficiently priced. As we will see, where the gas transmission network is not correctly priced, an argument arises for distorting the prices for electricity transmission.

As we will see, transmission charging policy is largely a matter of designing an efficient "two-part tariff". The "variable" or "marginal" part of this tariff was discussed earlier, and arises from differences in nodal prices across different locations. These differences, as we saw earlier, should reflect the marginal cost of the use of the transmission network between those locations, including both the cost of losses and congestion. Differences in these locational spot price give rise to a flow-of-funds to the system operator, known as settlement residues, which can be thought of as the revenue arising from these charges. The "fixed" part of the two-part tariff for the transmission network takes the form of additional, "fixed" transmission charges that do not vary with the quantity of electricity injected or withdrawn.

[25] More specifically, the forecast revenue depends on the shape of the price-duration curve for those prices at which the generator should normally be producing. A peaking generator cares only about the shape of the price-duration curve at times of very high prices. A baseload generator cares more about the overall shape of the price-duration curve.

[26] It is standard practice, when carrying out a partial-equilibrium analysis, to make the assumption that all upstream and downstream markets that are not directly the focus of investigation are competitive and therefore the consequences for these markets can be ignored.

As we have seen, achieving efficient short-run operational decisions is primarily a matter of setting the "variable" part of this two-part tariff efficiently. On the other hand, achieving efficient long-run investment and location decisions is primarily a matter of setting the "fixed" part of this two-part tariff efficiently.

As noted earlier, although the focus here is on getting the transmission price signals right, in practice, other policies such as a contractual arrangements or explicit rules and requirements (such as licence conditions) may also have a role in influencing investment and location decisions.

Do efficient locational marginal prices send efficient long-run investment signals?

At the outset it is important to emphasise that, of course, the policies for promoting efficient short-term operational decisions identified above also have a key role to play in promoting efficient longer-term investment and location decisions.

In particular, the arrangements for pricing the short-run marginal cost of the transmission network (in the form of locational marginal prices), and the policies regarding the allocation of any resulting "residues", also have an effect on long-run generator (and load) investment and location decisions. In particular:

(a) the shape of the price-duration curve at a particular location (coupled with any other side payments to generators) provides an important signal to generation entrepreneurs as to the efficient type of generation required by the market (that is baseload, mid-merit, peaking)[27]; and

(b) locational differences in average electricity spot prices (or, more precisely, locational differences in the shape of the price-duration curve, taking into account the time the generator will be using the transmission network), provide an important signal to generation entrepreneurs as to the efficient location for new generators in the market .

A key question to be addressed at the outset is the extent to which these short-run transmission prices can be relied on to efficiently signal long-run investment decisions. Is it the case that locational marginal prices (also known as 'nodal' prices) both promote efficient short-run operational decisions *and* longer-run location decisions? Or is something else required?

This paper argues that nodal pricing can send efficient long-run generator investment signals, but only under very strict assumptions which do not apply in practice. Specifically, nodal pricing will yield efficient long-run generator investment signals when (a) there are no economies of scale and scope in generation or transmission; (b) there is effective competition between generators at all locations on the network; and (c) transmission is augmented continuously so that at the average congestion cost on a transmission constraint is equal to the marginal cost of augmenting that constraint.

In the absence of economies of scale and scope, full nodal pricing, when coupled with this simple rule for efficient transmission augmentation, will ensure the fully-efficient electricity market outcome. That is, full nodal pricing will ensure both efficient short-run operational decisions, and efficient long-run investment/location decisions in both generation and transmission. Full nodal pricing ensures that generators continually face the short-run marginal cost (SRMC) of use of the transmission network, while the transmission augmentation rules ensures that the transmission network is augmented to the point where the long-run marginal cost (LRMC) of transmission expansion is equal to the average SRMC arising from generator re-dispatch. No further investment/location signals are required.

[27] See Stoft (2002)

But, in practice, of course, there are substantial economies of scale and scope in electricity transmission and some degree of economies of scale in generation. In the presence of economies of scale and scope can full nodal pricing yield efficient locational/investment signals?

The answer is no. Several papers in the economics literature make the point that, in practice, nodal prices alone cannot be relied on to send efficient generator location/investment signals. Fraser (2002) explains this as follows:

> "The problem in practice is that under Locational Marginal Pricing (LMP), there are numerous reasons why SRMC will virtually always be lower than LRMC. … New transmission will get built by RTO planners long before SRMC rises to LRMC. In other words, the locational price differences between A and B will almost always be lower than the long-run cost of building transmission between A and B".

SRMC pricing will yield price signals which are systematically below LRMC for the following reasons:

- Price caps in energy markets. As we have seen, the SRMC of use of the transmission network is signalled through differences in locational spot prices. But if spot prices are capped below the true value to customers of lost load, price differences will at best send a muted signal of the true marginal cost of the transmission network. This is a much more significant problem in those electricity markets which have a low spot price cap. For example, in the Northeast of the US, the cap is typically $US 1000/MWh, whereas the value of lost load is more likely to be in the region of $US 15,000-20,000 MWh. The current price cap in the NEM (at $10,000/MWh, shortly rising to $12,500/MWh) is closer to the true value of lost load, mitigating this concern somewhat.

- Transmission planners "err on the side of caution". Fraser (2002) explains "The business of transmission is very complicated and unpredictable. Transmission reserves step in to save the day when the unexpected happens. It is a widely held belief – and a justifiable one – that planners should err on the side of caution".[28]

- Transmission planners use reliability standards which are independent of economic costs. The problem here is that the same reliability standards are applied to remote customers and to centrally-located customers "… meaning the probability of outage for isolated (and transmission-dependent) customers is not orders of magnitude different than the probability of outage in more densely populated regions, despite the fact that the cost of achieving that level of reliability may be orders of magnitude different in distant locations on a dollars per MWh basis. It is more likely to be the case that SRMC<LRMC for transmission to distant or low load locations".

- Market power problems: "It has widely been argued that a legitimate reason for overbuilding transmission is to help solve market power problems and promote competition generally in power markets. Extra transmission increases the size of markets and can be used to avoid or mitigate alternative costly market power mitigation measures such as forced generation divestiture and bid caps".

[28] Brunekreeft et al (2005, 75-76) express this concern as follows: "As the costs of blackouts caused by inadequate transmission are very high, and the costs of somewhat over-building the network are rather modest, those charged with ensuring reliable supplies are likely to err on the side of too much rather than too little spare capacity. This further depresses the scarcity value of the network, lowering the dispersion of LMPs and hindering cost recovery (although it has an additional benefit in increasing the effective size of the market within which each generator bids, and hence reduces market power".

- National security: "The transmission system is perhaps the most vulnerable component of the electricity industry to attack, and is also the most logical area to build in redundancy so as to minimize the consequence of attack. There is a national security reason to build too much transmission".

- Economies of scale. Transmission "investments are 'lumpy' – i.e., it is impossible to precisely match transmission capacity with transmission requirement. … The result of this economy of scale is that transmission is commonly overbuilt – the cost of doing so is minimal, and it is a cheap way of acquiring additional reliability, of opening up markets, and providing national security. … because of the extent of economies of scale in transmission, the amount by which overbuilding reduces SRMC below LRMC is considerable".

Fraser (2002) concludes: "It is standard utility practice to have more transmission than redispatch savings alone would justify". These conclusions are echoed by many other commentators. For example, Rious, Dessante and Perez (2008) note:

> "Short run locational signals alone cannot efficiently coordinate generation and transmission investments".
>
> "Nodal pricing is seldom sufficient to coordinate the generation and transmission investments because lumpiness of transmission investment greatly decreases the differences in nodal prices that should signal congestion."[29]

These theoretical considerations are also borne out in practice. For example, the Pennsylvania-New Jersey-Maryland (PJM) market in the US uses nodal pricing, but there remain concerns that generators face inadequate location signals. The system operator has proposed modifying the capacity market (through a mechanism known as the Reliability Pricing Model, RPM) to include a locational component in the capacity charges. The Maryland Public Service Commission argues:

> "Locational marginal pricing in the energy market is a valuable source of information to investors, but it has not proven adequate to incent the investment community to invest in new generation in constrained areas. … The RPM should not be phased in without the locational component, because of the critical importance of this feature. Without the locational component, the resulting prices will not produce accurate price signals in areas needing investment. In addition, the resulting prices will almost certainly produce higher costs to consumers and capacity may be built in areas where it is not presently needed. The usefulness of the RPM would be significantly undermined if it is implemented without the locational component".[30]

In summary, although locational marginal prices can send efficient short-run operational signals to generation and load, and although these prices have some effect on long-run investment decisions, the conditions under which nodal pricing leads to efficient long-term investment

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[29] Brunekreeft et al (2005) link the location-signalling role of nodal prices to the cost-recovery problem: "For short-run congestion management there is an agreement that a system relying on LMPs works and is efficient (provided the bids are competitive). The more challenging question concerns the long-run effects of nodal pricing. … The question is closely related to the question whether LMPs recover all the costs of the network. If the LMPs recover all network costs then the LMPs unambiguously set the efficient investment signals for generation and load. In the long run, with optimal investment, the difference between LMPs would reflect marginal network expansion costs. Unfortunately, for various reasons LMPs do not recover all costs. Simulations suggest that even with optimal investment in generation and transmission long-run economies of scale allow only about 20-30% cost recovery".

[30] Maryland Public Service Commission Position Paper Concerning PJM's RPM Proposal, December 2004, page 6.

decisions are limited and unlikely to apply in practice. In particular, in the presence of economies of scale and scope in transmission and "lumpiness" of new investment in generation or transmission, it is not possible to rely exclusively on nodal price signals to promote efficient generator and load location decisions.[31]

In any case, since the NEM does not use nodal pricing, it is not possible to rely on locational marginal prices alone to promote efficient location decisions in the NEM.

Locational differentiation in the "fixed" transmission charges

In practice, some other instrument(s) or policies are needed to achieve efficient generator and load location decisions. The most important of these other policies are spatially-differentiated "fixed" transmission charges. That is, differences in the "fixed" component of transmission charges across different locations.

In effect, as we have seen, transmission pricing policies can be viewed as an exercise in designing a "two-part tariff". The "marginal" or "variable" component of this tariff is reflected in the locational differentials in the short-run locational prices for electricity. The "fixed" component of this tariff is reflected in other transmission charges which do not depend on the volume of electricity injected or withdrawn. For example, these charges could vary with the capacity of the connection to the transmission grid or the peak consumption of a load. By introducing spatial differentiation in these charges we can, in principle, achieve efficient location signals, no matter what mechanism is used for short-run pricing of the transmission network.[32]

Note that when discussing fixed transmission charges it is important to include all charges or costs incurred by generators or loads in relation to the use of transmission services, including any transmission assets owned by the generator or load itself.

It is possible to distinguish three different categories of these fixed transmission charges:

- connection tariffs (i.e., charges to recover the costs of the "spur" connecting a generator or a load to the shared transmission network);

- "use of system" tariffs (charges for the use of the shared transmission network);[33] and

- Any other charges applied to new generators or loads seeking to connect to the transmission network, such as charges designed to preserve the "firmness of access" of incumbent transmission customers.

As we will see below, the precise design of these fixed transmission charges in any given market will depend on circumstances particular to that market. However, we can make the following general observations on how these charges should be set:

(a) The impact of these charges on generator and load location decisions will depend on the *total forecast charges* for use of the transmission system – that is both the forecast

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[31] In contrast, both Frontier (2004) and Covec (2004) argue that the locational signals in New Zealand (from both nodal pricing and the "Grid Investment Test") are adequate. Covec (2004) notes: "Thus, while not providing a complete solution in all cases, the existing nodal pricing system combined with a well functioning GIT do provide (at least qualitatively) appropriate signals to potential investors in new generators to locate plant efficiently". (page 5).

[32] See CESI (2003).

[33] CESI (2003), page 17.

spatial differentiation in the short-run charges for the use of the transmission system (as reflected in spatially-differentiated locational marginal prices for electricity) and the forecast spatial differentiation in any additional fixed charges for the use of the transmission system. An immediate implication is that the nature and level of the fixed transmission charges will (of course) depend on the nature and level of the spatial differentiation in the short-run pricing arrangements. A market with nodal pricing (such as in New Zealand) will require less locational differentiation in the fixed component of transmission tariffs than a market (such as in the UK) with a single uniform price.[34]

(b) The impact of these charges depends on the *spatial differentiation* in the charges, rather than their absolute level. If there is no spatial differentiation in the charges (that is, if all generators or all loads pay the same charges no matter where they choose to connect to the transmission network) there will, of course, be no locational signals. On the other hand, it is not necessary (at least for efficient locational signals) for the charges to recover a particular level of revenue overall. In the extreme, for example, the fixed transmission charges for generators, say, might be set so as to recover no revenue overall. This could be achieved with positive charges in some locations and "negative" charges in others. This is, in fact, the practice in the UK:

> "In Britain for 2004/2005 the annual zonal generator tariffs range from £10.7/kW to -£6.8, a range of £17.5/kW. This is exactly half the interest and depreciation on a CCGT plant costing £310/kW at 10% interest and hence a strong locational signal, which requires some negative generator charges".[35]

(c) Furthermore, the efficient level of the fixed transmission charges will depend, in part, on the *pricing of substitutes*.[36] In particular, as already noted gas transmission is at least a partial substitute for electricity transmission. Gas transmission and electricity transmission operation and investment decisions must therefore, to an extent, be coordinated. If there is little spatial differentiation in charges for, say, gas transmission, highly-differentiated charges for electricity transmission may induce entrepreneurs to over-rely on the gas transmission network (e.g., generators could locate near loads, relying on the gas network to supply gas, rather than locating near the source of gas, relying on the electricity network to transport electricity to loads). Conversely, if there is little spatial differentiation in electricity transmission charges, investors may over-rely on the electricity transmission network (e.g., by locating generation facilities near gas sources).

Ideally, both gas and electricity transmission tariffs would broadly reflect the long-run marginal costs of providing these services. However, it is not possible (or not politically feasible) to set the charges for one of these services efficiently, it may make sense, as a second best, to "distort" the charges for the other.

The total transmission charges overall (including the fixed transmission charges, the short-run congestion revenues, and any revenues from ancillary services) should be set so as to recover the total costs of providing transmission services. But does it matter whether the total costs of the

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[34] Indeed, NERA (citation) and COVEC (citation) both argue against introducing locationally-differentiated fixed transmission charges in New Zealand (although, in my view, this is unjustified).

[35] Brunekreeft et al (2005), page 80. In the UK charges on generators recover around 20% of the total cost of providing the transmission network.

[36] This point applies of course to all transmission charges – not just the "fixed" component of transmission charges discussed here. For example, where there is short-run locational marginal pricing for gas, these may either accentuate or offset the locational incentives from locational marginal pricing of electricity.

transmission network are recovered predominantly from generators or predominantly from loads? Many (but not all countries) follow a practice similar to the NEM where transmission costs (with the exception of the costs of connection assets) are recovered virtually entirely from charges on loads. Does it matter who bears these charges?

Brunekreeft et al (2005) argue that as long as:

(a) the fixed charges have little or no impact on the operational decisions of generators or loads;

(b) the charges are locationally differentiated so as to achieve efficient investment/location decisions (even if the overall revenue raised is low or zero);

(c) we can ignore the prices of substitute services such as gas transmission; and

(d) the charges are set consistently across the interconnected transmission system.[37]

Then *the allocation of cost recovery to generators versus loads is essentially arbitrary.*[38] That is, there is no theoretical reason to prefer an approach which recovers more revenue from generators or from loads; however these costs are allocated, customers will (of course) pay the total cost of creating and sustaining the transmission network. Just to be clear, Brunekreeft et al (2005) are not arguing that it does not matter how the charges to generators are *structured*. They argue in favour of locational differentiation of the charges to generators. Rather they argue that the overall *level* of the charges to generators does not matter.

Furthermore, we can make the following points, which are expanded further below:

- The fixed transmission charges at the same location should be different for different generators and loads reflecting the different possible patterns of congestion on the network at the time that generator or load is making use of the transmission system;

- The total locational differentiation in charges between two locations should exceed the "incremental cost" of upgrading the transmission network to provide services between those two locations and should be less than the "stand alone" cost of upgrading the transmission network to provide services between those two locations.

- The transmission charges (both from short-run locational price differentials and from locational differentiation in the fixed transmission charges) should be stable over time, in order to facilitate sunk, complementary, location-specific investment by generators and loads.

Differentiation in fixed transmission charges

Different generators (and loads) have different patterns of output (or consumption) over time and therefore make different use of the transmission network. For example a baseload plant may be operating at-or-near its maximum output most of the time, and therefore is exposed to locational price differences on the transmission network no matter when they arise. In contrast a

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[37] This last condition is clearly necessary since if, for example, generators were charged are larger share of the transmission charges in, say, Queensland, than in NSW, new generation would have an incentive to locate in NSW to service load in Queensland.

[38] See Brunekreeft et al (2005), page 80: "In a competitive and isolated system, the proportions charged to generators and loads make no difference, as the final price paid by the consumer will be the generator cost plus" the total transmission charge, independent of how that transmission charge is allocated. Brunekreeft et al ignore the possibility of substitution with gas transmission at this point.

super-peaking plant may only operate for a few hours a year and will therefore only be exposed to any transmission constraints which arise at those times.

These different generators (or loads) should only experience differentiation in locational charges for transmission services which reflect the forecast future congestion on the network *at the time at which that generator is producing*. Therefore different generators should, in principle, face different locational charges for connection at the same location.

For example, let's suppose that a particular generation constraint is only binding at peak times. Let's suppose that these peak times account for 1 per cent of all the time periods in a year. But let's suppose that a particular peaking generator is only operating at times when this constraint is binding whereas a particular baseload generator is operating at all times, peak and off-peak. In this case the locational differentiation in the transmission charges for the peaking generator should be significantly larger than the locational differentiation in the transmission charges for the baseload generator.

In this example, the peaking generator should face a greater spatial differentiation in fixed charges than the baseload generator. But the opposite case – where the peaking generator faces less spatial differentiation than a baseload generator – is at least theoretically feasible. For example, suppose that a peaking generator is considering locating in SA or VIC. Let's assume that all other input costs are the same in both locations. Let's also suppose that although the VIC-SA interconnector is periodically constrained (leading to occasional price differences between SA and VIC) at times of particularly high prices in SA and VIC the interconnector is not constrained (since, say, periods of hot weather tend to coincide in the two regions). In this case, since, at the times when the peaking generator would be operating, there are no relevant transmission constraints, the peaking generator should not face *any* locational differentiation in its transmission charges.

The general principle, as stated above, is that since different generators and loads make different use of the transmission network, this should be reflected in differences in transmission charges, so as to induce efficient investment/location decisions.[39]

Cost-reflectivity in fixed transmission charges

As mentioned above, if there were no economies of scale and scope and no lumpiness in investment, the locational differences in transmission charges should reflect the long-run marginal cost of providing transmission services.

However, in the presence of economies of scale and scope in the transmission network (and in the presence of "lumpiness" of investment considerations), the notion of "cost" is illusory[40]. In the presence of economies of scale and scope, recovering sufficient revenue to recover the total cost of a network augmentation will inevitably require some form of allocation of joint and common costs across potential users of an augmentation. There is no longer a unique notion of "cost".

Nevertheless, even in the presence of economies of scale and scope, a common requirement is that the transmission charges for a customer (or a group of customers) yield revenue sufficient to cover the incremental costs of providing transmission services to those customers but not so large as to exceed the stand-alone costs of providing transmission services to those customers.

[39] This argument has not, to my knowledge, been made before. However the notion of differentiating charges to different generators at the same location is mentioned in Smeers (2005).

[40] "The transmission of electricity suffers from many undesirable economic properties that make the direct application of [marginal cost pricing] principles impossible. It combines both economies of scale and lumpy investments which make the definition of long run marginal cost illusory". Smeers (2005), page 1.

The requirement that charges at least cover the incremental costs of a service goes some way towards ensuring that transmission charges remain stable over time (as discussed below), since any network expansion results in incremental revenue sufficient to at least cover the incremental cost of that expansion. In other words, the incremental cost floor is one tool for ensuring overall stability of charges in the face of network expansion.

The requirement that charges not exceed stand-alone cost goes some way to preventing inefficient bypass of the network. In the presence of economies of scale and scope, as long as the network has sufficient spare capacity, a partial duplication of the network is socially-inefficient since it raises costs overall. Duplication or bypass can be prevented by ensuring that transmission charges do not yield revenue in excess of the cost of the bypass.[41]

It is worth emphasising that this floor and ceiling on the revenues attributed to a particular group of transmission services has one clear implication. In the case of transmission assets which are dedicated to serving a particular customer (known in the NEM as "connection assets"), the economies of scope with other transmission services are limited or nonexistent. In this case, the incremental cost and the stand-alone cost of these services are both roughly equal to the actual cost incurred in providing these connection services. In this case, the above principle suggests that the difference in charges between a customer's location and the point of connection to the shared network should reflect the cost of those connection assets. Put another way, generators or loads should be pay at least the cost of transmission assets dedicated to them alone. More generally, where there is a group of transmission customers which each share a "spur" to the main transmission network, this principle suggests that the transmission charges for those customers should yield sufficient revenue to at least cover the incremental cost of providing those transmission services.

This is, in fact, the practice in the NEM and in many other liberalised electricity markets overseas. That is, to my knowledge, it is a universal practice to require generators and loads to at least pay the cost of the transmission assets that are dedicated to their use.

In fact in many markets, including the NEM, these charges for connection assets are the full extent of the locational differentiation in transmission charges. That is, in these markets generators face no other locational differentiation in their transmission charges. This approach is sometimes known as "shallow connection charges" or "generation spur only"[42]. Rious et al (2008) observe:

> "The simplest option of network tariff is called the *generation-spur only*. The generators are then required to pay only for the line that connects them to the network and not for any other lines of the network. This method has a weak theoretical efficiency. It only incentivises the generators to be close to the network. An efficient network tariff would incentivise the generator to locate plants while taking into account the available transmission capacity and the transmission upgrading that may be needed to accommodate them. However, at least half of the European TSOs apply generation-spur only (ETSO, 2007)."

In some markets (particularly those with constrained-on/constrained-off payments), the short-term pricing and dispatch mechanisms provide either no location signals or even perverse location signals (encouraging generators to locate in congested locations, so as to receive constrained-on/constrained-off payments). In these markets there is, of course, a role for strong

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[41] The NEM Rules (clause 6A.26) allow for "prudent discounts" to be granted to transmission customers who cannot demonstrate that they have a credible bypass opportunity.

[42] CER (2004)

locational differentiation in transmission charges – beyond the shallow connection charges mentioned above.

As yet no consensus (either in theory or in practice) has emerged over how the locational differentiation in fixed transmission charges should be determined. There is a consensus that the charges overall should broadly reflect long-run transmission upgrade costs, but there remain numerous questions to be resolved, since the optimal long-run transmission expansion path depends on assumptions about future evolution of demand and generation opportunities, and, in the presence of economies of scale and scope, some arbitrary cost allocation is inevitable.

The UK, for example, uses an approach in which generators are grouped into different tariff zones. The differentiation in the tariffs across the zones is intended to reflect the long-run marginal cost of transmission expansion. As noted above, in 2004/05 the fixed transmission charges in each zone varied from £10.7/kW in the north of England to -£6.8/kW in the south. As Green (1997) explains:

> "Transmission users in England and Wales face regionally differentiated charges per MW of peak demand or generating capacity, which are intended to reflect National Grid Company's marginal investment cost of providing sufficient capacity. Generators have a significant incentive to locate in the south and west of England, where the load exceeds the local generation, as a result of these charges. Even so, the simplified algorithm used to calculate the charges may produce differentials which are smaller than the true difference in cost involved".[43]

The use of models to estimate long-run marginal cost have been criticised as being arbitrary and non-transparent. For example, Frontier (2004) observe that such models:

> "… tend to require large amounts of information about network conditions, involve complex and non-transparent modelling and vary over time as transmission customers arrive or depart. This introduces subjectivity and raises governance concerns about the bodies that have to calculate and implement these charges".

Stability/predictability of transmission charges

Although the locational differentiation in transmission charges is important for sending location signals to generators and loads, the *predictability* of the charges itself has an important impact on generator and load location decisions.

Generators and loads must make a substantial sunk investment in assets which are specific to a particular location. These investments are made in reliance – amongst other things – on a continuing supply of transmission services at a reasonable price. The potential for large unforeseen increases in transmission charges (sometimes known as "price shocks"), or a reduction in transmission services, is a disincentive to efficient sunk complementary investment.

In particular, where transmission charges are locationally differentiated, in order to reduce their exposure to the risk of expropriation of the value of their investment through higher transmission charges, generators and loads may choose to avoid locations which increase their reliance on the transmission network – such as locations away from major load centres – even when overall social costs are lower when the generator or load chooses a more remote location which relies more heavily on the transmission network.

This stability/predictability of transmission charges in turn can be broken down into three components: (a) predictability of the short-run transmission charges (as reflected in short-run

[43] Green (1997), page 181.

locational marginal price signals); (b) predictability of the fixed transmission charges; and (c) predictability of continuing access to transmission services.

As noted above, the short-run pricing of the transmission network is reflected in locational differences in the short-run electricity spot price. These spot prices are relatively volatile. Some studies suggest that this volatility will increase in the future with increasing reliance on wind and other weather-dependent generation. If, as seems likely, generators and large loads are averse to risk, the volatility of the electricity spot prices (and not just their average level) will itself have an impact on generator (and load) location decisions.

This volatility impact can be mitigated through hedging arrangements. In all liberalised electricity markets there exist financial contractual arrangements (such as swaps and caps) which allow generators to exchange a volatile spot price for a fixed price. That fixed price may be above or below the expected future value of the spot price, depending on the relative risk aversion of the different market participants. Since all generators seek to hedge a large proportion of their output, locational differences in the prices of hedge contracts are an important signal for location decisions. In addition, the relative prices of swaps and caps (with different strike prices) are a key signal for different types of investment (baseload versus peaking).

The efficiency of these hedge markets – and therefore the efficiency of generation investment and location decisions - can be improved by policies which facilitate the operation of the hedge markets themselves, and by policies which facilitate the hedging of the risk of trading across different price nodes (sometimes known as "basis risk"). The quality of the investment and location decisions can therefore be improved by improving the quality and availability of instruments for managing this basis risk, especially over longer time horizons.

This might be achieved, for example, by providing market participants with access to the financial "residues" created by locational price differences, or by policies to improve the depth and liquidity of markets in instruments for hedging basis risk. In the NEM, as discussed further in the next section, remote intra-regional generators *automatically* receive a share of the intra-regional settlement residues, which partially insulates them from the price effects of intra-regional transmission constraints (although as discussed below it does not insulate them from the risk of not being able to be dispatched to the quantity they desire). In the NEM, the residues that arise from inter-regional transmission constraints are auctioned back to the market as a hedging device. There has been discussion in the NEM about the need for "firm" financial instruments for hedging basis risk – sometimes known as (firm) financial transmission rights – which are available in some markets overseas.

Since transmission is a substitute for generation, one key determinant of long-run forecasts of spot price differences is the nature and extent of any future additions to or removals from[44] the transmission network. It is important therefore that generation decision makers are able to forecast which possible transmission augmentations will or will not go ahead. In particular, it is particularly important that generation decision makers can have some assurance that future spot prices will not *decrease* as a result of an inefficient transmission investment. Therefore a key policy in a liberalised electricity market is an instrument which provides assurance to generators that certain inefficient transmission investment will not be carried out.

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[44] Since the marginal cost of maintaining transmission facilities is relatively low, decisions as to the removal of existing transmission assets seldom arise. However, with the possible shift away from coal-fired generation, it is plausible that some transmission facilities will no longer be economic to maintain in the future. However, where existing generation has made a complementary sunk investment in a location in reliance on those transmission services, even uneconomic services should be maintained for a period of time, so as to maintain incentives for investment.

In the NEM the *regulatory test* plays this key role of restraining inefficient transmission investment, so as to promote efficient generator location decisions.[45]

Ensuring the stability/predictability of the fixed transmission charges, on the other hand, is primarily a matter of ensuring that the basis for determining the charges remains largely fixed over time. For example, a customer's charges should be largely independent of the configuration of other customers on the network. In particular, the entry or exit of a generator should not have a significant impact on the charges faced by other generators. For example, if two generators are currently sharing a transmission spur to the rest of the transmission network, and one of those generators chooses to shut down, the charges to the remaining generator should not materially increase. In addition, as we will see in the next section, concerns have been expressed in the NEM about the stability of the static intra-regional marginal loss factors.

Stability/predictability of access to transmission services

In markets where generators and loads face the efficient locational marginal price at the margin, generators are always able to produce as much as they desire given the local electricity spot price. In these markets, transmission congestion is entirely reflected in locational price differences. In contrast, in markets, such as the NEM, which do not rely exclusively on price signals to ration access to scarce transmission capacity, as we have seen, the presence of intra-regional congestion can leave a generator unable to produce as much as it would like to at the price it is paid. This was referred to earlier as the generator being constrained-on or constrained-off.

This inability to produce as much as desired due to transmission network limitations is also sometimes referred to as a lack of "firm" access to the transmission network. In markets with non-price rationing, the firmness of access to the transmission network in the presence of network congestion is another relevant locational consideration. In particular, generators have a disincentive to locate in regions where they will be unable to be dispatched for as much as they would like (either following their entry decision, or following the entry decision of a subsequent generator) even if those regions are the most efficient location for new generation entry. In addition, generators will have a disincentive to locate a region where they will be dispatched for more than they would like, even if that region is the most efficient location for new generation.

Shallow versus deep connection charges

In discussions of efficient transmission pricing, it is common to compare and contrast the pros and cons of "shallow" versus "deep" connection charges. A regime of "shallow" connection charges, as we have seen, would require generators to pay the cost of any connection assets, in addition to certain charges for the use of the shared transmission network.

But what, exactly, is a regime of "deep connection charges"? The AEMC's Transmission Pricing Issues Paper of November 2005 did not provide a definition. The suggestion is that under a system of deeper connection charges generators would pay more of the costs of transmission assets – at least those transmission assets which could be attributed in some way to that generator or group of generators.

As emphasised above, the principles of efficient pricing of the transmission network only require that the transmission charges on individual generators or groups of generators are sufficient to cover the incremental costs of providing a network capable of connecting those generators. As noted earlier, it is, in fact, common practice to require generators to pay the costs of their own connection assets.

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[45] In fact, since the decision to drop any ex-post prudency assessment of transmission investment, in principle there is little to stop a TNSP from carrying out a project which does not satisfy the regulatory test, although this has not happened to my knowledge.

The same principle applies to groups of generators.[46] We might interpret the phrase "deep connection charges" to refer to the requirement that not just individual generators, but also groups of generators pay transmission charges sufficient to cover the incremental cost of providing a network to those generators.[47]

However, the larger the group the more complex it is to determine the incremental cost of connecting those generators. In addition, given the presence of economies of scale and scope, much of the cost of the shared network is likely to be largely a joint cost which cannot meaningfully be attributed to individual generators or groups of generators. In the absence of further research on the cost structure of the transmission network, it is not possible to state definitively that the current charging policy in the NEM is inconsistent with such a policy of "deep connection charges".

There is some suggestion in some proposals for "deep connection charges" that the first generator to connect at a location should pay the full cost of any "consequent upgrade", while subsequent generators connecting at the same location would rebate some of the cost to the first generator. This approach seems undesirable for several reasons. First, it is inconsistent with the "proactive" planning approach, discussed below, in which it is the responsibility of the TNSP to determine which upgrades to carry out and how to share the cost of those upgrades. Second, it imposes significant and unnecessary risk on the first-moving generator. Third, it is inconsistent with providing stable and predictable transmission charges over time. In contrast, if a TNSP determines that an upgrade is desirable, it should proceed with the upgrade and determine how the cost of the upgrade will be recovered from both new and existing transmission customers over time.

In the NEM, as noted earlier, existing generators face a risk that transmission congestion will leave them unable to be dispatched for the full amount they desire at the price they are paid. The phrase "deep connection charges" is sometimes used to refer to a situation where new-entrant generators are required to pay for upgrades to the transmission network sufficient to restore the existing level of "access" of the incumbent generators. A detailed analysis of this option is beyond the scope of this paper. This approach might make sense in a context in which the intra-regional transmission network was built to a level where there is no intra-regional congestion under normal conditions. In that case this approach would give incumbent generators a degree of protection against inefficient subsequent entry (which is, itself, an incentive for new investment), while intensifying the location signals for new generators.

Summary

In summary, the policies for ensuring efficient longer-term investment and location decisions by generators include, in addition to the policies for promoting efficient short-term operational decisions, policies:

(a) regarding the setting of the fixed component of transmission charges, including policies for:

(i) determining the degree of spatial differentiation in fixed transmission charges for generator and loads, and how the charges vary across different generators and loads at the same location, including policies relating to charging for connection assets.

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46 For example, generators which jointly connect to a hub which is joined by a spur to the shared network.

47 As before, however, the charges on each generator are not necessarily the same – different types of generators should pay different charges even when they locate at the same node.

(ii) determining the degree of spatial differentiation in charges for substitute services such as gas transmission.

(iii) relating the spatially-differentiated charges to aspects of the "cost" of providing transmission services, such as the incremental cost or stand-alone cost; and

(iv) determining how to ensure that the fixed transmission charges remain stable or predictable over time.

(b) regarding the ability to forecast and/or hedge against short-term locational variation in electricity prices, including policies for:

(i) promoting instruments for the hedging of basis risk in the medium and long-term;

(ii) enhancing the predictability of transmission investments (including policies for limiting inefficient investment such as the regulatory test); and

(c) policies regarding the ability to forecast and/or hedge against variation in the availability of transmission services; including policies for:

(i) maintaining certain transmission services for a period of time in the face of declining demand for those transmission services; and

(ii) compensating or insulating transmission customers against the non-price consequences of network congestion.

2.3 Policies for efficient operation of and investment in the transmission network

Although other policies were mentioned and discussed, the previous two sections of this paper focused on policies related to efficient pricing of the transmission network. However, efficient pricing of the transmission network is not, in itself, sufficient to achieve efficient location and operation decisions by generators and loads. In addition the transmission network itself must be operated and expanded efficiently.

In particular, the achievement of efficient outcomes overall depends on the processes and procedures governing transmission operation and investment decisions. These processes and procedures include, for example, the rules and incentives governing, say, transmission maintenance policies, policies regarding transmission line ratings, transmission service quality, and transmission augmentation policies.

For example, despite efficient pricing arrangements, problems of unreliability on the transmission network due to a lack of maintenance may induce generators to inefficiently locate close to load. Achieving efficient generator location decisions requires not just efficient transmission pricing, but also efficient operation of the transmission network.

In the late 1990s there was some optimism that, just as operational and investment decisions in generation could be delegated to independent generation entrepreneurs, thereby relying on the forces of competition to achieve efficient outcomes, it was thought that operational and investment decisions in transmission networks might also be able to be effectively delegated to independent transmission entrepreneurs who would be incentivized to make transmission investments in response to observed differences in locational marginal prices.

Both the subsequent theory and the subsequent experience with "merchant transmission" has tended to dampen this optimism.[48] The current view seems to be that there is little, if any role, for reliance on merchant transmission to deliver efficient outcomes in a liberalised electricity market.

If there is little role for merchant transmission then we must rely primarily on regulated monopoly transmission networks. The performance of these regulated networks will depend, in part, of course, on the financial incentives created by the regulatory framework. This raises the question whether or not it is possible to design an effective regulatory framework which creates strong financial incentives for efficient operational and investment decisions by a transmission network operator.

In the economics literature there have arisen a few proposals regarding mechanisms for incentivising transmission network operators to operate and expand their networks efficiently. This approach is sometimes known as "performance based regulation" for transmission network operators. A full discussion of these proposals takes us beyond the scope of this paper. For the purposes of this paper I will put this possibility to one side.

Instead, the usual practice is to rely on regulatory arrangements with relatively weak financial incentives. This usually takes the form of rate-of-return regulation, coupled with some limited specific financial incentives. Where there are financial incentives, these usually focus on short-run operational rather than longer-term investment incentives. In the NEM, for example, TNSPs face financial rewards and penalties based on transmission line availability. The AER reports a measure of network congestion which could become the basis for a service quality incentive scheme in the future.

When it comes to ensuring efficient transmission investment decisions, on the other hand, in practice, primary reliance is placed on rules and policies governing network augmentation decisions rather than financial incentives. However, these rules and policies are not fully prescriptive; they leave some discretion in the hands of the transmission planner. Thus there remains the issue of the governance arrangements and the residual incentives on the transmission planner.

The key questions for our purposes are the following: do the rules and incentives on the transmission planner ensure that economically-efficient transmission upgrade projects of the right type, size and location will be chosen and carried out, while inefficient transmission upgrade projects will not be carried out? We can make the following points:

(a) The socially-optimal transmission expansion decision depends, in part, on the mechanisms for ensuring the efficiency of short-run dispatch;

(b) A determination of the socially-optimal transmission expansion path depends on access to information on future generation technologies and opportunities which is not necessarily information available to the transmission planner;

(c) The optimal transmission expansion path depends, in part, on the generation and transmission assets that have already been sunk. If transmission planners cannot commit to a particular path generators acting strategically may be able to influence the transmission expansion decision away from the socially-efficient path;

[48] See, for example, Joskow and Tirole (2005), Brunekreeft et al (2005).

Relationship between short-run dispatch and transmission planning

First, it is worth emphasising that the socially-optimal transmission expansion policy depends, in part, on the short-run efficiency of dispatch. As we have seen above, the short-run efficiency of dispatch can be affected by two factors: The level of competition in the market, and the mechanism for handling short-run transmission constraints.

Let's focus first on the level of competition in the market. It is now well-established that the impact of transmission augmentation on generator market power should be taken into account at the time of an assessment of a transmission upgrade. If generators are exercising market power, and if that market power is likely to persist in the market, overall social welfare may be able to be improved by, say, over-building a transmission link. The extra costs involved in that over-building may well be less than the cost to the market from persistent generator market power (in the form of inefficient short-run dispatch and inefficient longer-term generator location decisions). One of the key issues facing transmission planners around the world is how to take into account the potential inefficiency from generator market power when making transmission decisions.

The current version of the regulatory test explicitly allows transmission upgrade proponents to carry out modelling which takes into account the possibility for generator market power. The additional benefits of the proposed project (over and above the benefits that arise when generators bid competitively) is said to be the "competition benefits" of the upgrade proposal.

As we have noted (and as discussed further in the next section), the short-run efficiency of dispatch is also affected by the mechanism for rationing access to the transmission network. As discussed further below, at present in the NEM, intra-regional congestion is not currently priced. This gives rise to incentives for generators to distort their offers to the dispatch engine. This can lead to generators being dispatched "out of merit order", increasing the overall cost of dispatch.

Consistent with the approach discussed above, where this inefficiency in short-run dispatch is expected to persist, it should be taken into account when assessing a transmission upgrade proposal. As with generator market power, it may turn out, for example, that social welfare is improved by, say, over-building a transmission link to reduce the occurrence of inter-regional congestion. In fact, circumstances can arise where, in fact, it is cheaper to eliminate intra-regional transmission constraints entirely than to allow this inefficiency in dispatch to persist.

The AEMC's First Interim Report notes that:

> "There is a minimum level of network congestion that is efficient. To build sufficient network so that it is never constrained will be prohibitively expensive".[49]

This observation is consistent with economic theory[50], but that economic theory relies on the assumption that the short-run dispatch outcomes are efficient. Where short-run dispatch outcomes are inefficient (due to, say, mis-pricing) it may in fact be efficient to over-build transmission, even to the point where there is no intra-regional network congestion in normal operation.

The general point here is that the short-term inefficiency in dispatch brought about by mis-pricing of intra-regional constraints, should be reflected in the longer-term assessment of a possible transmission upgrade.

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[49] AEMC (2008), page 43.

[50] See, for example, Stoft (2006).

Transmission planning and information on generation opportunities

In principle, there are two possible conceptual approaches to transmission planning: Under the first approach, the transmission planner "moves first" and determines the optimal future network configuration and the optimal network expansion path. Generators and loads then take this expansion path as given when making their location and investment decisions. This approach is known as "pro-active" network planning. Under the second approach, generators choose their location decisions first and the transmission network is built to accommodate these decisions. This approach is known as "reactive" network planning. Research to date has argued that the pro-active approach leads to higher overall levels of social-welfare.[51]

A submission by a group of Victorian incumbent generators to the AEMC notes that TNSPs have shown a preference for "a greater role in locational planning which has the effect of distorting the decentralised decision-making the NEM is based upon". However, as noted, research suggests that in fact transmission planners *must* engage in a degree of "locational planning" and should not rely exclusively on "decentralised decision-making" by generators when it comes to location decisions.

However, in practice, this approach raises certain issues, particularly regarding access to information. In effect, the transmission planner must decide which generation locations will be exploited in the long-term efficient expansion path and which locations will not be socially beneficial to exploit. The transmission planner therefore must indirectly determine which potential generation resources will be exploited and which will not.

To do this task properly, of course, the transmission planner needs information. In fact the transmission planner needs information on the location, type, cost, and size of all possible future generation expansion opportunities. While this information may possibly have been available to a transmission planner in a vertically-integrated industry, vertical separation of transmission and generation limits the information the transmission planner has about future generation opportunities.

In fact, one of the primary benefits of vertical separation is that it creates strong incentives for private generation entrepreneurs to discover and make use of new information – including possible new generation locations, new technologies, or new ways of operating old technologies. The problem is that this information must somehow be communicated back to the transmission planner so as to allow for efficient long-term transmission planning.

The next section of this paper discusses how the "clusters and hubs" proposal of the AEMC may be viewed as, in part, a mechanism for improving the flow of information to transmission planners.

Transmission planning and the commitment problem

The optimal transmission expansion path depends, in part, on which assets are already sunk. In particular, once a generator has committed irrevocably to a particular location, it may make economic sense to augment the transmission line to that location, even if it would not have made sense to augment that transmission line ex ante. If the transmission planner cannot commit to *not* making certain upgrades ex post, there arises a risk that generators or loads might seek to act strategically, sinking investment in the expectation that the transmission network will subsequently be upgraded.

This potential problem has been noted several times in the economics literature. For example, Brunekreeft et al (2005) note:

[51] See Sauma and Oren (2006)

> "The second problem is that the TSO may find it difficult to commit to its transmission expansion schedule regardless of generator decisions. … A [generating] company may prefer to locate instead in an export-constrained zone, predicting that the TSO will have to invest in extra transmission. Once the generator has made its decision, the least-cost way for the TSO to fulfil its license obligations to deliver security of supply and adequate capacity may be to expand transmission capacity. This combination of the G and T investment would be more expensive than the least-cost expansion plan, but given the G investment, might be socially preferable to not investing in transmission. If the TSO had been able to commit to not investing in additional transmission, the low prices in the export-constrained zone might have deterred the generator from its investment and encouraged the least-cost solution".[52]

Although the theoretical possibility of an inefficient outcome is generally recognised, the practical significance of this issue is still debated. For example, some commentators argue that it would be very hard in practice for a generator to obtain bank financing in the absence of adequate load in the vicinity or adequate transmission capacity to carry power away from its proposed location, or at least in the absence of a commitment by the TNSP to upgrade the network in the short-term.

Summary

In summary, the policies for ensuring efficient operational and investment decisions by transmission network operators include policies:

(a) governing the financial incentives on transmission network operators to maintain high levels of availability, especially when most desired by the market, including policies relating to the maintenance practices, timing of maintenance, and line rating practices;

(b) governing the determination as to when to upgrade and when not to upgrade the network including policies:

  (i) determining when a potential transmission augmentation should not proceed (due to the presence of lower-cost alternatives in the form of generation or demand-side management) (as in the current regulatory test);

  (ii) determining how the short-term dispatch outcomes are taken into account in the long-term planning process, including the possible presence of generator market power and the possible distortion to dispatch offers due to mis-pricing; and

  (iii) governing the ability of a transmission planner to commit to a particular transmission expansion path;

  (iv) governing the flow of information on new generation opportunities to the transmission planner;

  (v) governing the incentives on the transmission planner to analyse and undertake welfare-improving transmission projects.

2.4 Groups of consistent, complementary policies

The previous sections have separately focused on each of the three main groups of policies identified at the outset: (a) policies for promoting efficient short-run generator and load operational decisions; (b) policies for promoting efficient longer-run generator and load

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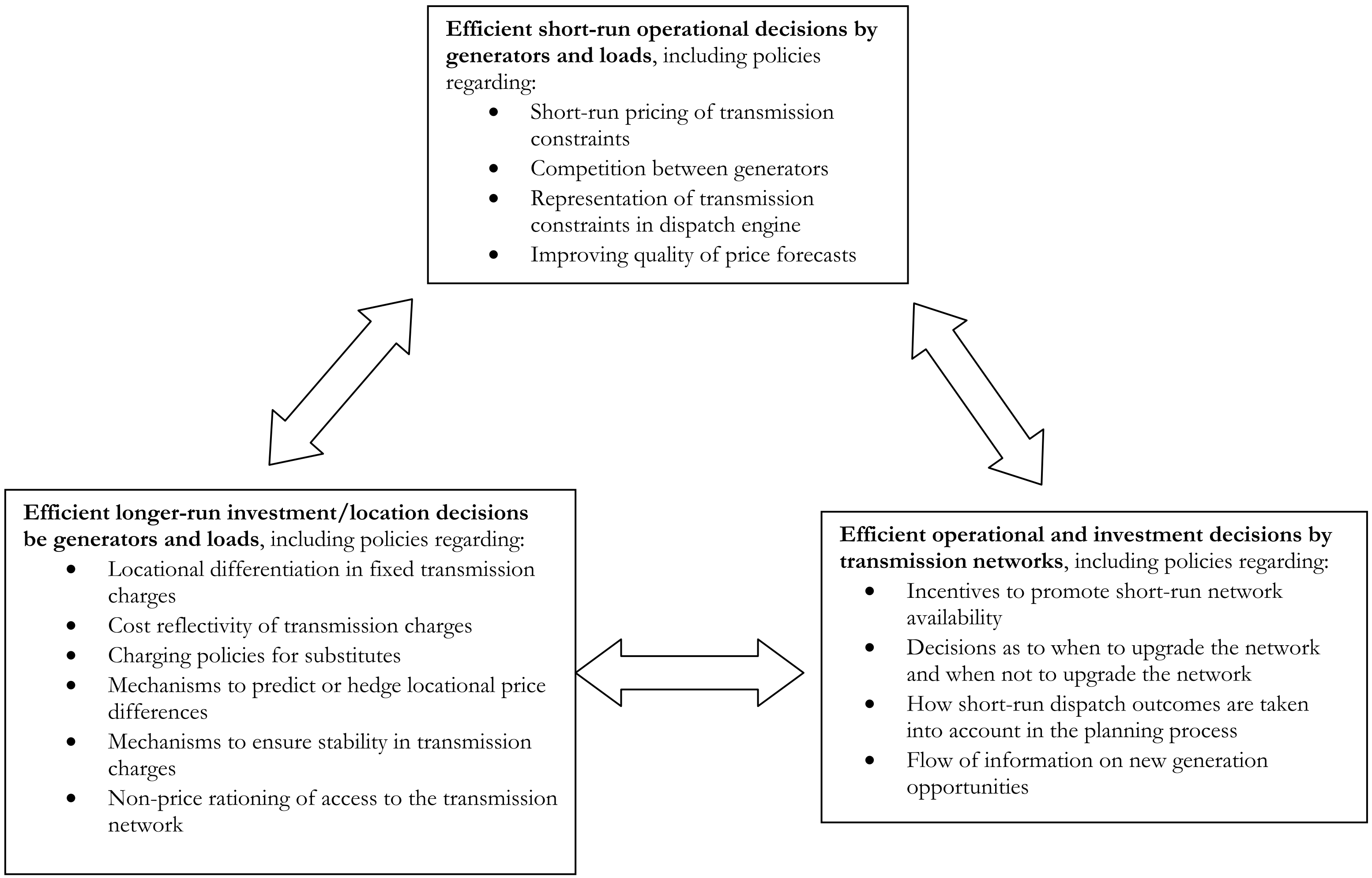
[52] Brunekreeft et al (2005), page 77.

investment/location decisions; and (c) policies for promoting efficient transmission operational and investment decisions. However, as mentioned earlier, it is clear that these policies interact – that is, the optimal choice of policies under each of these headings depends, to an extent, on the policies chosen under the other headings.

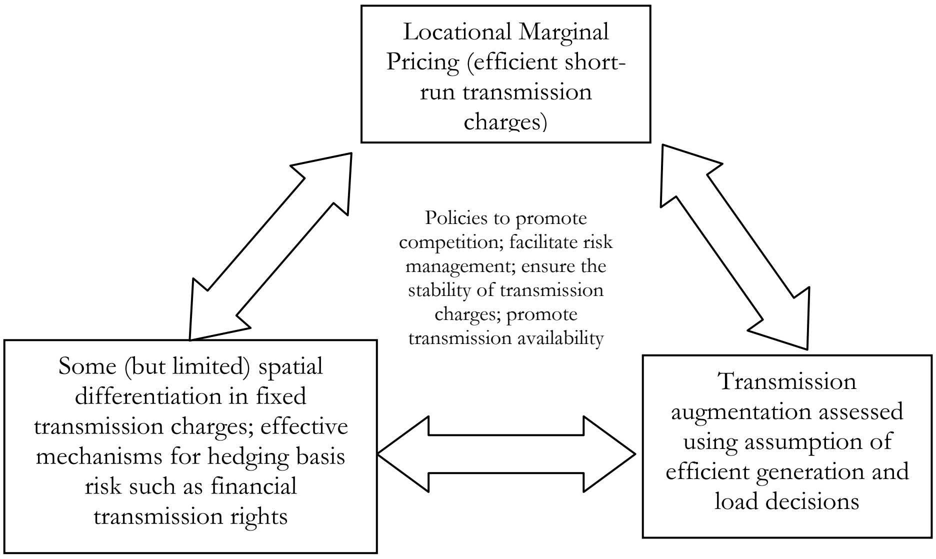
This interaction between groups of policies is highlighted in the summary diagram overleaf. As this diagram emphasises, the optimal policies for transmission expansion, say, will depend, in part, on the choice of policies for short-run dispatch of generation. Similarly, the choice of policies for fixed transmission charges, say, will depend on both the transmission expansion policy, and the short-run pricing policy.

Figure 1: Framework for transmission policies



An important observation to make is that it is possible to identify groups of internally-consistent sets of policies. For example, the decision to rely on nodal pricing to price short-run access to the transmission network is consistent with the decision to use some (but limited) spatial differentiation in transmission charges and the decision to assume efficient short-run dispatch when assessing transmission augmentation. This group of complementary policies are illustrated in figure 2 below:

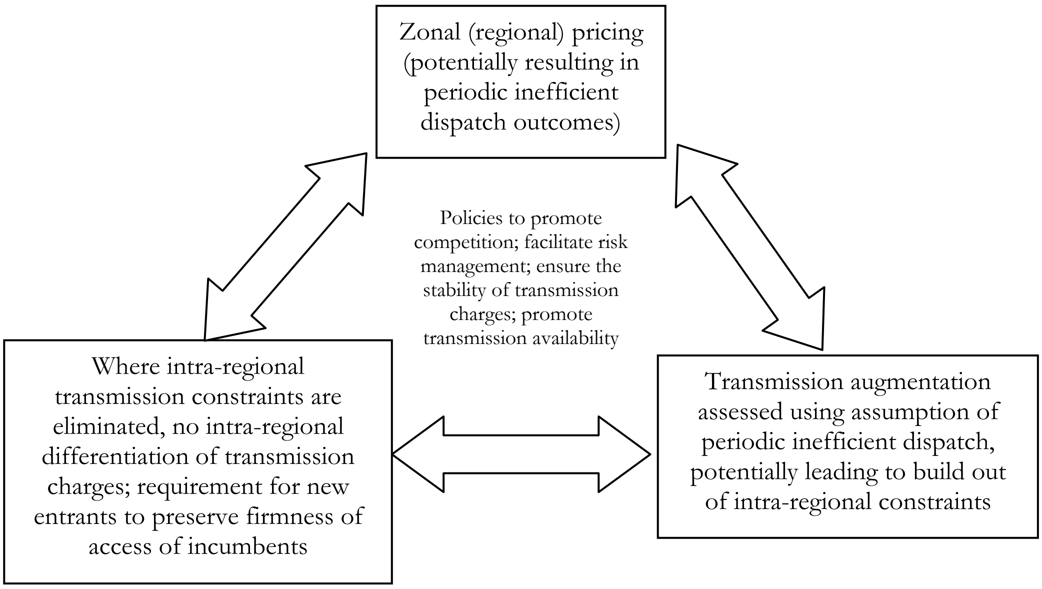
Figure 2: Internally-consistent transmission policies based around nodal pricing



As is well known, the NEM does not currently use full nodal pricing. Instead, the NEM makes use of a form of zonal pricing. As discussed further in the next section, under certain circumstances this results in inefficient dispatch outcomes. Therefore, it would be consistent to take these inefficient dispatch outcomes into account when considering the merits of a transmission upgrade. Indeed, as noted above, under some circumstances it may make sense to augment the transmission network to the point where intra-regional transmission constraints are eliminated. Where this is carried out, it would be consistent (as at present) to have no further intra-regional spatial differentiation in fixed transmission charges.

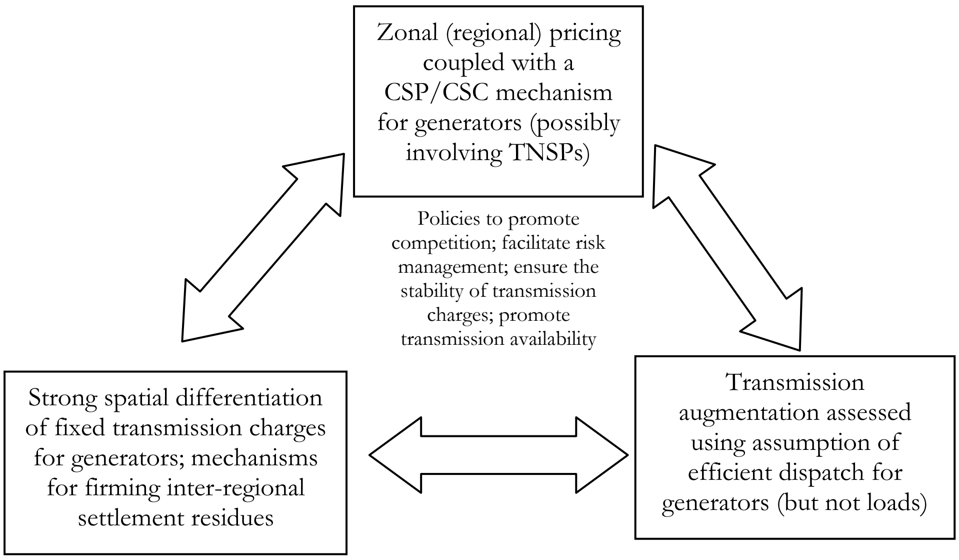
This group of policies would not (we might expect) lead to an outcome as efficient as the group of policies above, however, the policies are, at least, consistent with each other. This group of complementary policies is illustrated in figure 3 below:

Figure 3: Internally-consistent transmission policies based around zonal (regional) pricing



As a third possibility, it might be possible to introduce some form of constrained-on, constrained-off payments in the NEM (for example, in the form of a CSP/CSC mechanism). This would result in efficient short-run dispatch outcomes at least for generators, so it would be consistent to assess the merits of any transmission upgrade using the assumption of efficient dispatch for generators (although perhaps not for loads). On the other hand, this policy would (in the absence of other measures) result in generators being rewarded for locating in constrained-off regions. This could be offset, in turn, through strong spatial differentiation in fixed transmission charges, as in the UK. This group of complementary policies is illustrated in Figure 4.

Figure 4: Internally-consistent transmission policies based around zonal pricing with a CSP/CSC mechanism



III. Preliminary assessment of the current transmission policies in the NEM

Having set out the linkages between different transmission policies in the previous section, let's briefly explore potential issues with the application of these policies in the NEM, particularly in the light of the climate change policies mentioned above.

3.1 Policies for efficient short-run generator and load operational decisions

In the previous section we noted that the policies for promoting efficient short-run generator operational decisions could be divided up into policies for

(a) ensuring that each generator (and load) faces a price that reflects the short-run marginal cost of the transmission network;

(b) improving the accuracy of the representation of losses or physical transmission limits in the centralised dispatch process;

(c) improving competition between generators (and/or loads) at each location on the network;

(d) policies for improving the quality of price forecasts (and information flows between transmission and generation); and

(e) improving the range and efficiency of the markets for ancillary services.

The potentially significant change in the market brought about by climate change policies raises several issues which fit within this heading, as set out below:

Price caps

In order for prices to reflect the short-run marginal cost of the transmission network at all times, prices must be allowed to rise to a price that clears the market. The current price cap in the NEM is set quite high by international standards (and is scheduled to increase shortly). Nevertheless, it is appropriate to keep the level of this price cap under review, especially if an increase in wind generation results in a reduction in the duration of price spikes needed to compensate for the fixed costs of peaking generators. In addition, several submissions to the AEMC raised the issue of the level of other possible price caps (such as the so-called Cumulative Price Threshold) and the coordination of the gas and electricity markets when these price caps are binding.

Five-minute/Thirty-minute dispatch

At present the NEM determines a separate spot (energy) price in each of five regions in each five-minute interval. However, this spot price is subsequently averaged to form the price that market participants actually face, in each thirty-minute "trading interval". In effect, short-run price changes are smoothed over time. This discrepancy between the five-minute and thirty-minute prices can, under some circumstances, induce inefficient outcomes.

The difference between five-minute and thirty-minute prices is particularly relevant when the price is changing frequently, and high short-term prices are needed to induce efficient operational decisions by generators or loads.

In particular, a very short-term spike in the spot price may be necessary to signal a lack of ramping capability in a particular region. When market demand or supply conditions are changing rapidly, the rate of change of output may exceed the ramping ability of the lowest cost generators. In this case the dispatch engine will seek to raise the price to induce other, higher cost, but faster ramping generation (or load) to come on line. But the price-smoothing effect of the thirty-minute averaging may precisely eliminate the market signal that is required.

This problem may not be significant when both demand and supply is fairly predictable (as at present). However potential problems arise when supply is largely weather-dependent as it would be if there were a significant increase in wind generation. A report by ESIPC (2005) emphasises that wind generation is volatile in all time-frames, from a few seconds to several hours. In particular, there is the potential for wind output to vary significantly from one time period to the next. With increased penetration of wind generation this rate of change of output may, at certain times, exceed the ramp rate ability of other generators to respond. In these times, temporary price spikes are necessary to signal the need for fast-ramping generation to remain on line. But such price spikes cannot occur under current market arrangements.[53] Consideration may need to be given to either moving to five-minute trading intervals, or introducing a separate mechanism to financially-reward investment in fast-response generation.

Generator competition

With regard to the level of competition in the NEM, there is currently at least periodic/intermittent market power exercised in the NEM. As noted above, in theory this has the potential to distort both the short-run efficiency of dispatch, and to distort longer-term generator investment decisions.

The overall impact of climate change policies on the level of market power in the NEM is unclear. It is possible that climate change policies, by increasing the cost of the cheapest generators in the market and increasing the capacity of gas-fired generation, might lead to a "flattening" of the overall supply curve, at least for generators in the middle of the merit order. On the other hand, a large influx of wind generation capacity might displace generation elsewhere in the merit-order, which could cause a sharp increase in market power at those times when the wind is not blowing.

In addition, there is a possible secondary interaction of climate change policies on generator market power through the hedge markets. It is well established that the incentive to exercise market power depends strongly on the degree to which a generator is hedged, which in turn depends on the pricing and availability of products in the hedge markets. The impact of a significant volume of wind energy on the hedge markets is unclear and, to my knowledge, has not been explored. Wind generators do not naturally hedge using swap or cap products which implicitly assume a stable volume of output. A large increase in wind generation therefore may reduce the supply of such products, potentially increasing the price. This might induce retailers to take lower levels of cover, potentially leaving generators more exposed. Further exploration of these questions is desirable.

Unlike many liberalised electricity markets overseas, the NEM has no explicit policies for control of generator market power. It is possible that there will arise a need to revisit this position in the light of the developments in the market in response to climate change policies.

Representation of losses and constraints in the NEM

With regard to the representation of losses and physical transmission limits in the dispatch process, two potential issues emerge. The first relates to the current policy of reflecting intra-regional losses (which vary dynamically with flows on the network) with static intra-regional marginal loss factors. This approximation of dynamically changing losses with a static marginal loss factor will result in some generators receiving "incorrect" price signals at certain times. It is theoretically possible that this problem will become more significant if there is a substantial amount of new investment in remote generation capacity.[54]

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[53] See ESIPC (2005), page 62. NEMMCO, in its submission to the AEMC's first interim report notes: "The fluctuations of concern to NEMMCO can occur in a timeframe shorter than the NEM's settlement interval of 30 minutes. This dulls the financial incentives associated with a 5 minute price signal".

[54] There is also a potential problem of stability of these factors, as discussed below.

Perhaps more importantly, it is my understanding that a marginal loss factor for a given node is calculated without taking into account the nature of the generator (or load) at that node and therefore without taking into account the times at which that generator will be producing. The losses on the transmission network vary with total flows. A generator producing only at off-peak (low flow) times could experience on average a much lower loss factor than a generator producing only at peak times. Alternatively, with a significant increase in the penetration of wind energy in the market, flows on the transmission network could vary significantly with wind output. Two generators could be connected to the same point on the transmission network, but a generator which produces only at the same time as other wind generators could face quite different marginal losses than a generator which only produces at times when wind generators are not producing. Yet, under the current arrangements, this is not taken into account when determining the static marginal loss factors.

The second potential issue relates to the representation of the physical network in the dispatch process. The existing NEM dispatch engine uses a linear approximation to the true physical constraints. This approximation seems to be "good enough" in most circumstances. However there have been calls for a move to a more accurate representation of the underlying physical network in the dispatch process. For example, one approach might be to develop an accurate real-time physical simulation of the real physical network capable of producing, as an output, a set of linear constraint equations for use in the constrained optimisation process. It is unclear to me whether or not climate change policies will increase the materiality of this issue.[55]

Price forecasts

As already noted, the efficiency of many short-run operational decisions of generators and loads depend on the quality of short-term price forecasts. Maintaining the quality of these forecasts may be difficult in the face of a significant increase in weather-related (wind or solar) generation. As noted by the AEMC, NEMMCO has already put significant resources into developing the Australian Wind Energy Forecasting System (AWEFS)[56].

In a similar light, if there is a significant increase in gas-fired generation capacity in the NEM, there is likely to be further integration of the gas and electricity spot prices. There may arise a need for further integration of the gas and electricity market notification and price forecasting services.

In the NEM at present there are mechanisms for forecasting short-term and medium-term electricity spot prices, known as STPASA and MTPASA. These mechanisms rely on bid information submitted by generators in advance of the real-time dispatch. The quality of the resulting price forecasts are only as good as the quality of the bid information supplied. Under the present rules primary reliance is placed on the good faith of generators to honestly forecast and submit their likely future bids. However, generators are allowed to change their bids ("rebid") in the event of a material change in circumstances. The increasing reliance on uncertain or unpredictable weather-related generation may increase the scope for subsequent rebidding. In the future it may be necessary to consider limiting the extent to which generators can change their bids in response to a change in circumstances, so as to improve the value of the STPASA and MTPASA processes.

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[55] Another, related potential issue is the use of real-time line ratings (which vary with say, temperature and wind conditions) to allow each transmission line to be operated up to its actual physical maximum given the weather conditions – essentially allowing the use of reduced "safety margins". Again, the extent to which climate change policies will affect the need for real-time line ratings is unclear.

[56] See NEMMCO, "Australian Wind Energy Forecasting System", presentation to NEM Forum, August 2008.

Similarly, NEMMCO points to a lack of transparency in the degree of demand-side participation as a factor which makes forecasting difficult. NEMMCO notes that: "the process currently undertaken to establish a quantity of non-scheduled, price-responding load and generation in MTPASA and SOO forecasting is yielding unsatisfactory data".[57] As the quantity of price-responding load in the market increases, it may be necessary to take steps to require disclosure of price-response mechanisms in operation, or to require large loads to be registered as scheduled.

Ancillary services

In addition to the efficiency of the spot (energy) market price at each location, efficient short-run operational decisions require efficiency in the markets for ancillary services. Under the current arrangements in the NEM a number of markets for so-called frequency-control ancillary services are operated in parallel to the energy market. These markets appear to be broadly competitive most of the time. However, a couple of concerns have been raised:

(a) First, in principle, in the presence of transmission constraints, FCAS services may need to be sourced locally. At present there are arrangements in place for FCAS to be sourced from a particular region (rather than on a NEM-wide basis) but there are no arrangements in place for sourcing FCAS on a sub-region when transmission considerations require it.

(b) Second, although the NEM has established markets for FCAS, there are at present, no markets for the provision of reactive or inertia services. Instead, the provision of such services has been made a requirement of connection agreements. Although reactive power must usually be sourced locally, it is relatively cheap to provide. Nevertheless, in the absence of any financial rewards for providing these services, the theoretical possibility arises that the lowest-cost provider of these services may simply choose to shutdown (either temporarily or permanently) rather than continue to provide these services to the market.

The development of a financial incentive to provide these services is likely to improve short-run generator operational decisions regarding unit commitment and longer-term shutdown decisions. This point is emphasised by a group of incumbent generators in Victoria who, in a submission to the AEMC, note:

> "Provision of a wider range of ancillary services through market arrangements will help maintain system reliability and security in an economically efficient manner and increase the life of plant that provides these services that may otherwise have closed pursuant to the CPRS and MRET".[58]

(c) Third, there is the issue of the quantity of FCAS services to purchase. It is likely that a significant increase in the penetration of wind energy would increase the volatility of very-short run imbalances in supply and demand, increasing the volume of FCAS services required to maintain a given level of security and reliability. This raises questions as to how the additional volume of FCAS required will be determined, and who should pay. There is a question of the extent to which any additional FCAS costs should be passed back to the "causer". It is my understanding that this has not been the case in the past. For example, it is my understanding that the large 760 MW unit at Kogan Creek

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[57] NEMMCO submission to AEMC's first interim report, page 6.

[58] AGL, International Power, Loy Yang, TRUenergy, submission in response to the AEMC Review of Energy Markets in light of Climate Change Policies, February 2009, page 14.

increased the FCAS requirement for the NEM, but that unit was not required to pay the additional costs.

Non-scheduled generation

The present arrangements in the NEM place generators into three categories: scheduled, semi-scheduled and non-scheduled. The scheduled and semi-scheduled generators must submit offers to the dispatch process, and must follow the dispatch targets provided back in return. Non-scheduled generators, in contrast, simply produce as much as they want at the prevailing regional reference price.

The presence of non-scheduled generators in the market is not a significant problem as long as the total volume remains small. However, it is possible that technological developments in the future might lead to an increasing volume of small or "embedded" generation, such as small solar installations or small-scale fuel cells. This raises several possible concerns:

(a) First, non-scheduled generation is effectively dispatched "ahead" of other generation in the market. In the presence of transmission constraints, other scheduled generators in the market are essentially forced to accommodate the non-scheduled generation. This has several consequences. First, it worsens the dispatch inefficiency arising from mis-pricing (which is discussed in detail below). Second, it potentially leads to reliability or security issues. Third, the limited locational signals that exist in the NEM for scheduled generators (discussed below) are completely absent. Such generators have no disincentive to locate in congested parts of the network.

(b) Second, since the output of non-scheduled generation is not separately quantified, increasing volumes of non-scheduled generation cannot be separated from changes in demand, making long-term trends in demand (and in non-scheduled generation) harder to identify and forecast.

(c) Third, non-scheduled generators do not provide ancillary services; nor are they penalised for increasing the need for ancillary services. Sudden changes in output, for example, increase the demand for ancillary services, but non-scheduled generators do not contribute to the increased cost. ESIPC (2005) notes:

> "On the whole, the ancillary services operate on a causer-pays basis where the cost of providing the relevant service is paid for by the individual or group of market participants that create the requirement for the service. Conversely, those participants who can supply ancillary services are able to earn extra revenue in the market. Under the current rules [non-scheduled generators] will neither pay for the ancillary services that they cause nor be able to earn revenue from the provision of such services".[59]

The Congestion Management Review and Problems with Regional Pricing in the NEM

The AEMC's Congestion Management Review highlighted a number of potential issues with the current arrangements for short-run pricing of the transmission network in the NEM.

As the Congestion Management Review highlighted, one central issue in the NEM arises from the decision of the NEM designers to rely on a regional or "zonal", rather than a "nodal", pricing framework. Specifically, under the current arrangements in the NEM, a single price is determined for each NEM region. The existing NEM regions may be quite large (one region covers all of

[59] ESIPC (2005), page 33.

Queensland, for example). The boundaries of these regions do not necessarily coincide with boundaries of the pricing regions created by the relevant binding transmission constraints. All generators and loads within a region pay or receive the same price (which is the price at the regional reference node).[60]

Putting aside the static intra-regional representation of losses (discussed above), as long as there are no intra-regional constraints, this “zonal” approach would yield the same outcome as full nodal pricing – congestion on the transmission network would be correctly priced.

Problems arise, however, when an intra-regional constraint is binding. In this case the pattern of dispatch of generators in a region has to be altered relative to a hypothetical “unconstrained dispatch”. Some generators will have to produce more and other generators will have to produce less than they would in the absence of the intra-regional constraint. When those generators whose output is increased or decreased are located away from the regional reference node, they will continue to receive the regional reference price for their output, but will be dispatched for less than or more than they would like to produce at that price.

A generator that is dispatched for less than it would like to produce, given the price it is paid, is said to be “constrained off”. Such a generator has an incentive to manipulate its offer to the dispatch process in order to try to increase the amount by which it is dispatched. For example, it might do this by lowering the price at which if offers its output. If there is more than one generator in this circumstance, each competes to undercut the others in an attempt to be dispatched. This results in a “race to the bottom” where all affected generators offer their output at the legal price floor in the market, which is $-1000/MWh.

Generators may also try to manipulate the other parameters in the bidding process, such as the use of ramp rate constraints or “fixed load” bids in order to prevent being dispatched for less. The AER has, on occasions, successfully prosecuted such behaviour as a breach of market rules. However a mere misrepresentation of costs (bidding $-1000/MWh) is not a breach of the market rules.

Problems arise when generators misrepresent their true costs in this way. In particular, the dispatch engine, perceiving these generators to be very low cost, will dispatch these generators ahead of other generators – including possibly generators in other regions. As a result, generators are dispatched “out of merit order”, raising the overall cost of meeting load and reducing overall market efficiency.

This behaviour does arise in the NEM. Various studies of the materiality of this problem were carried out and submitted to the AEMC in the context of the Congestion Management Review. In a presentation at the ACCC Annual Regulatory Conference in 2006 I highlighted one specific episode in the NEM when 71% of the total output of generators in Queensland and 99% of the total output of generators in Tasmania were offering their output at $-1000/MWh.[61]

To make matters worse, when a constrained-off generator distorts its offer in this way, and the generator is dispatched ahead of other generators in other regions, negative settlement residues can arise (that is, the flow between two regions may be in the opposite direction to the price difference) which limits the effectiveness of the inter-regional settlement residues as a device for

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[60] Strictly speaking, remote generators and loads pay or receive the regional reference price adjusted by a static factor designed to reflect average marginal losses between that generator’s node and the regional reference node. Losses on flows between regions are dynamically modelled and accurately priced.

[61] Biggar, Darryl, (2007), “Getting the prices right in the NEM”, presentation at the ACCC Annual Regulatory Conference, 26-27 July 2007. The incident in question happened on 13 June 2007.

hedging inter-regional basis risk, and gives to a potential revenue adequacy problem for NEMMCO[62].

A similar effect happens when a generator is dispatched for more than it would like to produce given the price it is paid. In this case, the generator is said to be "constrained on". Such a generator has an incentive to pretend to be a high-cost generator, offering its output at the legal maximum (currently $10,000/MWh), or to pretend to be unavailable, or to use ramp rate or other bidding parameters to prevent being dispatched for more. This bidding behaviour can result in a risk to reliability, requiring NEMMCO to use its directions power. This was once a problem in far-North Queensland until it was resolved through a contractual arrangement with a generator.

To summarise, the use of "zonal" rather than "nodal" pricing in the NEM implies that, when intra-regional constraints bind, some generators do not face the correct marginal price for their output. These generators are induced to distort their offers to the dispatch engine, which reduces the overall short-run efficiency of the NEM.

The mis-pricing implicit in the NEM's "zonal" pricing arrangements will inevitably result in some degree of short-term operational inefficiency. This was recognised by the NEM's designers. However, under the NEM's original conception, where this mis-pricing became persistent and material, new NEM regions would be created. However, this has proved politically sensitive in practice. When NECA originally proposed introducing more regions in Queensland a "moratorium" was placed on region boundary changes. The only region boundary change that has occurred since the start of the NEM involved the *abolition* of the Snowy region – rather than the creation of any new regions. The creation of new regions in the NEM looks unlikely going forward.

There are a few other liberalised electricity markets around the world which, like the NEM, rely on a system of "uniform" or "zonal" prices. However, virtually all of these other markets make use of a system of side-payments to generators to ensure that generators face the correct price for their output at the margin. These compensation payments or side-payments are known as "constrained on" and "constrained off" payments (or sometimes as "constrained up"/"constrained down" payments). Virtually every other uniform or zonally-priced market in the world uses some form of constrained-on/constrained-off payments. Ruff (2004) observes:

> "The Australian NEM may be the only uniform-priced market in the world operating with neither constrained-up payments nor constrained-down payments. NEMMCO can and does constrain generation up and pays constrained-up payments in emergency situations, but the philosophy is to use longer-term solutions".[63]

> "Of the markets discussed above, only Australia does not routinely make constrained-up payments, and even here emergency constrained-up payments and network support contracts are used when necessary. Only Australia and Alberta have lasted for long without constrained-down payments, and this is because they are sparse, radial systems that invest to keep congestion small. The ISO-New England uniform-priced market 'worked' for some years without constrained-down payments primarily by setting the

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[62] The mechanism NEMMCO uses to address this revenue adequacy problem also reduce the usefulness of the inter-regional settlement residues as a tool for hedging basis risk.

[63] Ruff (2004), page 14.

uniform price so low that few resources were constrained down and many were constrained up”.[64]

The current NEM rules allow for the possibility of constrained-on and constrained-off payments by TNSPs to affected generators. This possibility has not yet been taken up. It is not entirely clear why not.

The influx of new generation capacity anticipated in response to climate change policies may worsen congestion, increasing the extent of the inefficiency brought about by mis-pricing. Further consideration may need to be given to mechanisms for either eliminating intra-regional congestion, or for ensuring that generators face the correct price signals at the margin.

Summary

To summarise the following possible issues have been identified as arising in the NEM, particularly in the light of climate change policies, which affect short-run generator and load operational decisions:

- Zonal pricing arrangements leading to generator mis-pricing, generators distorting their offer parameters, and a resulting inefficient dispatch outcome. Possible solutions involve improving the price signals at the margin, such as through additional regions, or some form of constrained-on/constrained-off payments, such as the CSC/CSP proposal.

- Market price caps, which may limit the extent to which the market can signal the need for peaking generation, or which may affect the interaction with the gas market. Possible solutions might involve raising the price cap (as is currently proposed).

- Thirty-minute price averaging, which may limit the extent to which prices can signal the need for fast-response generation or load. Possible solutions involve moving to five-minute prices, or specific financial incentives for investing in fast-response plant.

- Potentially increasing levels of generator market power, possibly compounded by changes in the hedge market (although this has not been demonstrated). Possible solutions involve additional transmission, or bidding restrictions on some generators.

- Misrepresentation of true losses in the form of static marginal loss factors. Possible solutions involve moving towards generator or load profile-specific loss factors, or dynamic modelling of intra-regional prices.

- Deterioration in the quality of price/dispatch forecasts, due to an increase in the penetration of variable wind energy coupled with lack of transparency about demand-side participation. Possible solutions involve further development of wind forecasting technology (as is currently underway) and further requirements to disclose demand side response effects.

- Increase in the demand for FCAS services, including possible increased requirement for local sourcing of FCAS. Possible solutions involve arrangements for enhancing causer-pays for FCAS services, and changes to market rules to allow sub-region definition of FCAS requirements.

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[64] Ruff (2004), page 20. Alberta has an explicit policy of building out the transmission network so as to eliminate constraints. Section 8(1) of the Electric Utilities Act, part (f) states that the system operator will “make arrangements for the expansion or enhancement of the transmission system so that, under normal operating conditions, all anticipated in merit electric energy … can be dispatched without constraint”.

- Lack of financial incentive to provide certain ancillary services (such as reactive power) which may lead to inefficient decisions to shutdown temporarily or permanently. Possible solutions involve establishing markets or other mechanisms for rewarding generators who provide these services.

3.2 Policies for efficient longer-term generator and load investment/location decisions

In the previous section we noted that the policies for promoting efficient longer-run investment and location decisions included policies related to:

(a) the degree of spatial differentiation in fixed transmission charges, and the variation in those charges across different types of generators and loads at different locations;

(b) the degree of "cost reflectivity" in fixed transmission charges;

(c) ensuring stability in fixed transmission charges over time;

(d) the ability to predict or hedge short-run transmission congestion over the medium term and long-term; and

(e) the ability to predict or hedge variation in the availability of services on the transmission network (at least that component that cannot be hedged through prices).

Let's examine how these policies operate in the NEM, starting with the short-run transmission pricing and dispatch arrangements, before moving to the arrangements for "fixed" transmission charges. One key overall question – which, as we shall see, is difficult to answer – is whether or not the current arrangements in the NEM provide the correct overall locational signals for generators and loads.

Short-run pricing and dispatch arrangements in the NEM

As noted in the previous section, all generators and loads in a region pay or receive the same price, adjusted for a static marginal loss factor. The static marginal loss factor does provide some, if small, locational incentive.

However, one issue that has been raised (in addition to the issues raised above) is that these loss factors are not necessarily stable over time. As noted above, a generator must make a substantial sunk investment in its location, in reliance on forecasts of the future static marginal loss factor. The more volatile those loss factors, the greater the "safety margin" the generator must build in to its forecasts. For example, if another generator locates close to an incumbent generator, the losses experienced by the incumbent generator may increase substantially (since losses are proportional to the square of the power flow). This problem of instability in loss factors may become more acute if there is a substantial relocation of the existing generation capacity. This problem is noted in the AEMC's report:

> "Stakeholders indicated that there may be a significant degree of uncertainty regarding the losses that NEMMCO applies from year to year. Network flows, and therefore losses, can be significantly affected by new generation connections, particularly at relatively constrained parts of the network. For example, TRUenergy has cited an example of a year-on-year change of 25 per cent in the static loss factor"

As emphasised earlier, the risk of a material adverse movement in transmission charges (such as through a change in the static marginal loss factor) is a deterrent to making a sunk investment in sub-regions which rely heavily on transmission. Instability in loss factors therefore deters remote generation location.

Viewed broadly, the key problem is that annual updates to marginal loss factors are far too infrequent to signal efficient short-run use of the network, but are far too frequent (relative to the life of the generation assets) to effectively incentivise efficient investment. This problem could be solved through the introduction of both (a) more frequent updates to loss factors (such as loss factors computed dynamically, on a five-minute basis); combined with (b) mechanisms which allow generators to insulate themselves against changes in the marginal loss factors over time.

Putting aside the intra-regional losses, as we have seen all generators and loads in a region of the NEM pay or receive the same price. In the absence of any price signal, therefore, the locational incentives within a region of the NEM depend primarily on quantity signals. Put another way, the extent of the locational signals in the NEM depends primarily on the amount that each generator can expect to be dispatched at each location – that is, the issue of the "firmness" of dispatch.

The amount that a generator can expect to be dispatched when an intra-regional constraint binds depends on the severity of the constraint, the number of other constrained generators, and the configuration of the network. However, in general, it is unlikely that a constrained generator will be able to be dispatched for the amount it would like to be dispatched given the regional reference price. One reason is simply that when there are two or more generators that are constrained-off they have an incentive, as we have seen, to offer their output at the market price floor. The dispatch engine, seeing several generators offering their output at the same price, will "back off" each generator the same amount by dispatching each generator in proportion to its total availability. Unless a generator can manipulate its total availability it is highly unlikely that the generator will be dispatched for the full amount that it desires.

It seems clear that this uncertainty over dispatch in the face of congestion is, itself, something of a deterrent to investing in certain locations. A group of incumbent generators in Victoria, in their submission to the AEMC write:

> "Given the way current access arrangements are being interpreted it is not possible for generators to manage the risk of being congested at some time in the future. This has the following impacts on generators:
>
> - New entrant generators are unable to manage their access to the reference node for the life of the project, and therefore will face difficulty in justifying the investment; and
>
> - Incumbent generators face unmanageable risks, and may be forced to … reduce their levels of contracting at the system node as the only way to minimise exposure to congestion".[65]

These generators describe the current arrangements as "an environment where predictable generation revenue for the life of a project is not available – and this is why the current congestion regime is a significant barrier to investment".

In summary, under the current arrangements, remote intra-regional generators face no price risk in trading with the regional reference node, but do face some quantity (dispatch) risk. This lack of firmness is something of a deterrent to selecting remote intra-regional locations. At the same time, however, generators in the NEM do not currently pay charges for the use of the shared network (as discussed below), which offsets this disincentive to remote location somewhat.

However, it would be wrong to give the impression that these two effect in some way "cancel each other out". In theory the optimal location for a generator depends on the type of the generator, the different input costs it faces in different locations, and the different levels of

[65] Submission by VIC generators to the AEMC, page 19.

congestion it would face in different locations. There is not likely to be a link between the magnitude of the deterrence to choosing remote locations noted above and the relative productive efficiency of a generator. That is, while it may be fully efficient for a low-cost generator to locate in a constrained location (even if that means displacing some of the output of incumbent generators) under the existing arrangements a generator will be deterred from doing so to the same extent whether it is high cost or low cost.

Overall it would be surprising if the current arrangements in the NEM (particularly the lack of firm access) gave rise to anything like efficient location signals for generators.

In addition, in the NEM at present, new generators are not required to compensate incumbent generators (or TNSPs) for any reduction in the "firmness" of access brought about by the new generator's location decision. Although further analysis of this possibility is required, I noted that a requirement of this kind might make sense in a context in which there was a policy that the transmission expansion path will eliminate all intra-regional congestion given an efficient configuration of generation investment. In this case, any generator that reduced the firmness of another generator would, by definition, be an inefficient investment.

As noted above, the problem of lack of firm access could also be overcome by improving the short-run price signals in the NEM through some form of compensation payments for constrained generators (or through additional NEM regions, coupled with the further development of more effective ways to hedge inter-regional trading risk).

Transmission charging arrangements in the NEM

In the NEM at present generators pay only "shallow" connection charges – that is, each generator is only required to pay the cost of any transmission assets specifically and exclusively associated with that generator. These are known in the NEM as connection assets. Generators pay no other general transmission charges (known in the NEM as Transmission Use of System or TUoS charges). The bulk of the costs of the transmission network are recovered from loads using a cost allocation methodology known as "Cost Reflective Network Pricing".[66]

Although the current policy of requiring generators to pay for connection assets provides some location signals, it is a relatively weak and imperfect signal – it only provides incentives to locate close to the shared transmission network, rather than incentives to locate in the optimal location on the shared transmission network. As noted above, it would be surprising if the current arrangements in the NEM gave rise to efficient location signals for generators.

In principle, the location signals for generators could be improved by introducing some form of fixed transmission charges for generators. The locational differentiation in these fixed charges would depend on whether or not constrained-on/constrained-off payments were adopted. The precise form of these charges would require some development.

Furthermore, generators in the NEM face some risk that those transmission charges that they do pay will change in the future. For example, a situation might arise where two generators are sharing a spur line. If one of those generators decides to cease production, the spur line may be reclassified as a connection asset for the remaining generator, significantly increasing its transmission charges. Mechanisms should be developed to ensure that generators have a reasonable assurance that their transmission charges will remain stable over the life of their investment.

[66] At present this methodology is applied by TNSPs. This raises the question of whether or not TNSPs apply the methodology in a consistent manner across the NEM.

There are some potential examples of questionable location decisions in the NEM in recent years. This paper briefly looks at two cases: the new generator at Kogan Creek and the new generator at Uranquinty:

Kogan Creek

In mid 2007 a large (760 MW) coal-fired generator at Kogan Creek in QLD started producing. The output of this generator has a direct impact on potential flows northwards from NSW into QLD.

Since Kogan Creek started producing the constraint equation which has most frequently set the limit on northwards flows out of NSW into QLD has been a constraint equation of the form:

Flow on QNI + 0.9x Output of Kogan Creek <= 1000 (approximately)[67]

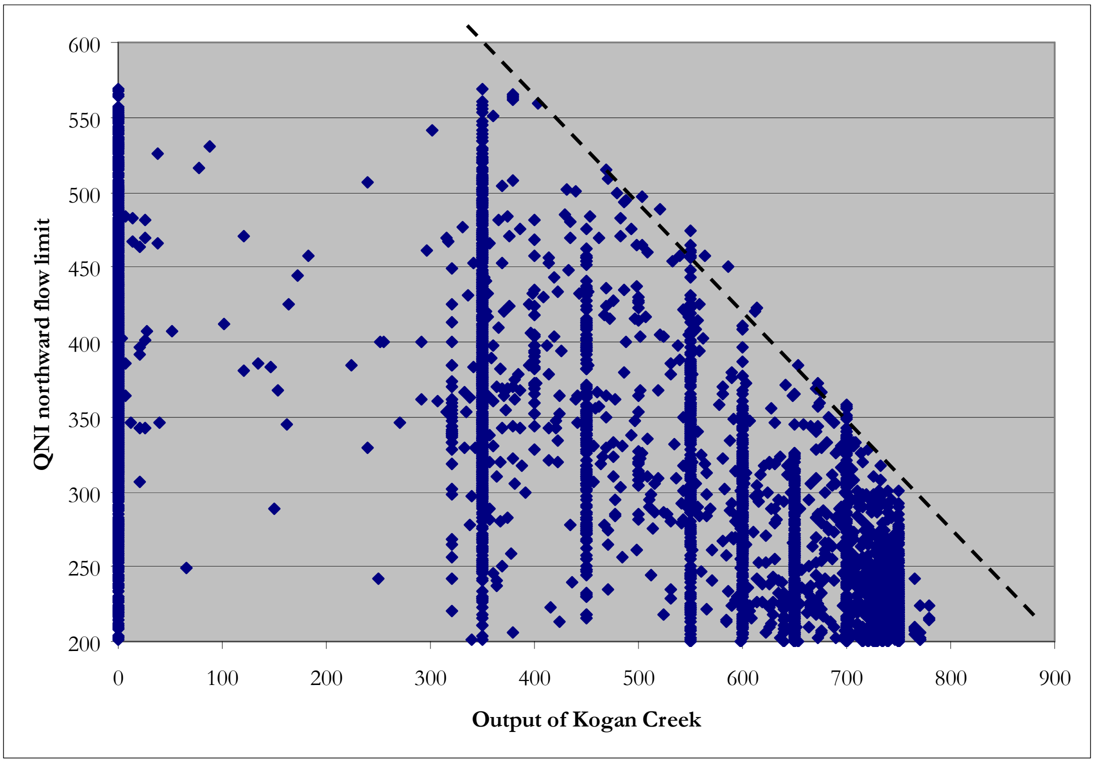
This constraint equation implies that when the output of Kogan Creek is at its maximum of 760 MW, the northward flow on QNI is restricted from a "normal" maximum of around 550 MW down to around 300 MW. Since Kogan Creek is primarily a baseload generator, its output is near its maximum the majority of the time (its output has been greater than 700 MW 60 per cent of the trading intervals since the start of this year). This has a material impact on the QNI northward flow limit. Since the start of this year, the average northward flow limit when Kogan Creek is producing at more than 700 MW has been 106 MW. In comparison, the average northward flow limit when Kogan Creek is producing less than 100 MW is 341 MW. In effect, this one generator location decision has wiped more than 250 MW off the capability of the NSW-QLD interconnector.

The effect of Kogan Creek output on the northward flow limit can be seen clearly in the following chart (figure 5). The chart shows the QNI northward flow limit against Kogan Creek output since the start of 2008. As can be seen, as the output of Kogan Creek increases (above around 350 MW), the northward flow limit decreases almost one-for one.

Since the coefficient on Kogan Creek output in the above constraint equation is very similar to the coefficient on QNI flow, when the above constraint is binding Kogan Creek can be viewed as being effectively (from the perspective of efficient pricing) in the NSW region. However, Kogan Creek receives the QLD regional reference price. In other words, when this constraint is binding Kogan Creek is mis-priced, and is "constrained off" in the manner discussed above. Kogan Creek can, in this case, increase its output by offering its output at a low price – potentially displacing lower-cost generation elsewhere in the NEM.

[67] This is the constraint equation "N^^Q_NIL_B1" which protects against voltage collapse in the event of the loss of Logan Creek. This constraint equation set the northward flow limit 60 per cent of the time.

Figure 5: Effect of Kogan Creek output on QNI export limit



Uranquinty

Another possible example of a generator which potentially has faced inappropriate location signals is the 640 MW gas-fired generator at Uranquinty in NSW.

As noted above, a generator is mis-priced when its output appears on the left-hand side of a binding constraint equation. If NSW had no intra-regional constraints (as the NEM was originally designed) a generator would never appear on the left-hand side of any binding material intra-regional constraint.

In fact the output of the generator at Uranquinty appears on the left-hand-side of around 1000 constraint equations in NEMMCO's most recent constraint library. It is not possible, without further research to deduce from this the materiality of the mis-pricing at Uranquinty. However, we can compare this situation to that of Snowy Hydro. The situation of Uranquinty is similar to the number of constraint equations affecting Lower Tumut (around 1300) and about twice the number affecting Murray (around 500). The problem of mis-pricing in southern NSW was significant enough to induce Snowy Hydro to push for a region boundary change. All of that mis-pricing will also affect Uranquinty.

In the majority of these constraint equations (75 per cent) Uranquinty has a positive coefficient, suggesting that it would be constrained off (in the remainder it is constrained-on). Without further analysis of the constraints that are binding in practice, it is not possible to determine whether or not, in the event of greater locational differentiation of prices in the NEM, Uranquinty would face a higher or a lower price on average.

Overall, this analysis suggests that it would be surprising if further detailed analysis revealed that Uranquinty was located in a socially-optimal location overall.

Summary

To summarise, the following possible issues have been identified as arising in the NEM, particularly in the light of climate change policies, which affect longer-run generator and load investment decisions:

- The lack of "firmness" of access by remote intra-regional generators to the regional reference node, deterring investment in remote intra-regional locations. Possible solutions involve improving the price signals for short-run pricing of congestion, coupled with arrangements for hedging those price differences, such as through constrained-on/constrained-off payments.

- The lack of spatial differentiation in the TUoS charges, which, when coupled with a lack of pricing of intra-regional constraints, limits the incentive of generators to make efficient intra-regional location decisions, taking into account the impact of their location decision on transmission congestion and the long-run upgrade path. Possible solutions include some form of locational differentiation, such as the application of "Cost Reflective Network Pricing" to generators.

- The lack of certainty over connection charges arising from other generator entry/exit decisions. Possible solutions include "locking in" connection charges for incumbent generators.

3.3 Policies for efficient transmission operational and investment decisions

In the previous section we noted that the policies for promoting efficient transmission operational and investment decisions include policies regarding:

(a) the incentives on transmission network operators to maintain high levels of availability;

(b) the assessment of transmission augmentations (and the "hurdles" for establishing when a transmission augmentation should proceed);

(c) the flow of information to the transmission planner on new generation opportunities;

(d) the incentives on transmission planners to analyse and undertake beneficial transmission augmentation projects.

In the NEM, a lot of attention has been paid to the regulatory test despite the fact that the regulatory test cannot force a transmission network operator to carry out an efficient transmission investment, it can only prevent inefficient investment. In the previous section it was argued that the assumptions used in the regulatory test should reflect the short-term dispatch and pricing outcomes in the market. Specifically, the assumptions used in assessing the regulatory test should reflect both the exercise of market power in the NEM and the distortion of bidding brought about by intra-regional congestion and mis-pricing.

At present, although the current rules governing the regulatory allow scope for modelling to include an assessment of the effects on competition, I suspect that an attempt to model the effects of mis-pricing in the context of a regulatory test assessment would be incompatible with the current regulatory test rules. This seems to be inconsistent with the current arrangements for short-term pricing and dispatch.

Furthermore, as discussed in detail in the AEMC's report, the current arrangements in the NEM which require TNSPs to keep connection applications confidential may limit the flow of information to transmission planners, particularly information concerning the overall economic benefit of an extension of the transmission network to a new "hub". The AEMC's report sets out several options to address this potential issue.

Finally, issues have been raised in the past concerning the incentives for TNSPs to make investments which improve inter-regional flow, especially when most of the benefits of the investment would fall on generators or loads in other regions. These issues, which relate to the incentive arrangements on TNSPs, and the arrangements for inter-TNSP compensation, have been previously raised in the NEM, and will be partially addressed with the establishment of AEMO.

Summary

To summarise, the following possible issues have been identified as arising in the NEM, particularly in the light of climate change policies, which affect transmission operational and investment decisions:

- The lack of consideration paid in the regulatory test to the potential for inefficient dispatch arising from intra-regional constraints. Consideration of this inefficiency would increase the tendency to "over-build" the intra-regional network, which may be efficient when this inefficient dispatch is not corrected in other ways.

- The possible inability of TNSPs (due to confidentiality requirements) to signal a potential network expansion requested by a market player, so as to learn more information about the full extent of the likely generation opportunities at that remote location. The AEMC's report sets out various possible solutions to this issue.

IV. Conclusions

Concerns have been raised that the proposed climate change policies will, amongst other things:

- Have an impact on overall system reliability due to a mis-match in the timing of a large increase in the amount of new generation capacity (primarily gas-fired generation and wind generation) the retirement of some existing generation capacity.

- Lead to a large (and potentially inefficient) need to upgrade the gas and/or electricity transmission networks due to the intermittency of new wind generation capacity and its propensity to locate in remote areas.

- Increase the volatility (and weather dependence) of electricity spot prices, increasing the demand for ancillary services, and increasing the frequency of opportunities for the exercise of significant market power.

- Increase congestion on the transmission network – including both inter-regional and intra-regional congestion.

The AEMC is seeking to review the current electricity market arrangements to verify that it is robust in the face of these concerns.

This paper has sought to present a framework for the analysis of transmission policies. In particular, this paper has sought to set out the full set of policies – both policies for ensuring efficient short-run operational decisions, and policies for ensuring efficient longer-run investment and location decisions by both generation and transmission – and to show how those policies "fit together".

In particular, this paper has emphasised the linkages between the policies for (a) short-run pricing and dispatch in the light of transmission congestion; (b) the setting of transmission charges for generators and loads; and (c) the rules governing augmentation of the transmission network.

In addition, the paper has carried out a preliminary review of the current arrangements in the NEM in the light of the proposed framework. The key relevant policies in the NEM are:

- The policies regarding short-run pricing and dispatch, including the current practice of using five-minute/thirty-minute averaging, zonal/regional pricing, combined with static intra-regional marginal loss factors, and no constrained-on/constrained-off payments.

- The policies regarding transmission pricing, such as the current practice of charging generators only for their connection assets, with the bulk of transmission network costs recovered from loads through a process known as "Cost Reflective Network Pricing".

- The policies regarding transmission augmentation – particularly the incentives that exist for constructing new transmission assets and the role of the regulatory test in controlling that investment.

The discussion has highlighted the potential conflict between short-run and long-run objectives. Achieving efficient short-run operational decisions in the electricity industry requires short-run marginal pricing of electricity and the use of the transmission network. The resulting price signals can be highly volatile. Generators and loads are understandably reluctant to sink large investments without some protection against adverse movements in the charges for the use of the transmission network. The discussion has highlighted the key role played by hedging instruments (including instruments for hedging basis risk) as a tool for reconciling these short-term and long-term objectives.

The current arrangements in the NEM are largely internally consistent with one exception. Specifically, the current policies in the NEM are internally consistent if we make the assumption that the network within regions is constructed and augmented in such a way as to eliminate all intra-regional congestion.

Under this assumption, the absence of explicit mechanisms for handling intra-regional congestion makes sense, as does the absence of strong intra-regional location signals for generators.

The current approach in the NEM (at least under this assumption) also has certain advantages. For example, generators receive reasonably firm assurance of access to at least load in their own region. In addition, generators face relatively low risk of substantial unforeseen changes in their transmission charges (since they pay no TUoS charges). There still remain some problems with the inter-regional settlement residues, but hedging inter-regional trading risk would not be affected by problems arising from intra-regional constraints.

However, this paper argues that there is at least one inconsistency in adopting this perspective: At present, although the short-run dispatch inefficiencies from market power can be taken into account in the assessment of a transmission augmentation, the short-run dispatch inefficiencies resulting from intra-regional congestion and mis-pricing cannot. As a result, the augmentation process has a bias against the build-out of intra-regional constraints.

This suggests that one possible way forward for the NEM would be to explicitly recognise the impact of intra-regional constraints when conducting an assessment of a transmission augmentation in the regulatory test or, alternatively, simply adopting a policy (as in Alberta, Canada) of building-out intra-regional constraints.

Such a policy is clearly "second best" in the sense that it results in more transmission network being constructed that is strictly efficient. However, as noted, the policy has some advantages in, for example, providing generators relatively firm assurance of access to at least their local regional reference node, and it also has the side benefit of reducing the scope for the exercise of market power. The materiality of these secondary benefits is difficult to assess.

However, the costs of maintaining a policy of building-out intra-regional constraints may increase in the future if there is a significant increase in remotely-located generation opportunities (particularly generators seeking to exploit remote wind or solar opportunities). It may be necessary to consider either (a) placing these remote locations into separate NEM regions; or (b) ensuring that generators in remote locations collectively pay at least the incremental cost of the required transmission expansion. The AEMC (2008) raises possible approaches that would involve remote generators collectively funding network extensions to remote locations.[68]

Alternatively, the NEM could be made more robust to long-term generation expansion and location decisions by taking steps to improve the handling of intra-regional congestion in the NEM, for example through some form of constrained-on/constrained-off payments. This would be consistent with the current approach to assessing transmission expansion (which assumes efficient short-run dispatch), but would be inconsistent with the current transmission pricing methodology. If a system of constrained-on/constrained-off payments were adopted, it would be desirable to introduce a system of strong locational-differentiation of transmission charges for generators, as in the UK.

In any case, as this paper has emphasised, the set of transmission policies should be viewed as an integrated whole which work together to achieve the overall NEM objective.

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[68] AEMC (2008), page 40, options 2 and 3.

Appendix: Brief survey of international practices[69]

Argentina

Argentina uses a system of full nodal pricing system, which is based on energy bids and a capacity adder. The "congestion rental" from energy bids is credited to the SALEX fund which is used to subsidise the development of new lines, while the surplus from the capacity adder contributes to paying for the transmission network. There is currently a proposal to auction firm transmission rights which is on hold but may be approved soon.

Transener adopts a shallow approach to connection charges (the costs of spurs are, however allocated to particular users). Transener charges national standard rates for connection depending on voltage level and standard rates for transformers. These rates do not relate to the actual costs incurred to connect particular customers.

Transmission charges on the shared network are determined by allocating 80% of the costs to generators, 20% to the consuming users.

There are no specific rules for dealing with reinforcements of the shared network required by generators to the high voltage network - the general user driven methodology applies. Namely if generators are constrained-off due to a limitation of transmission capacity, they can create a consortium to sponsor reinforcing the network. If the load in a distribution territory is increasing and the main grid is reaching the limit of its capacity, then the distributor will be liable for penalties if there is unserved load. Consequently, it may either promote or build local generation, or sponsor reinforcing the grid.

Marginal losses are calculated on a nodal basis for each hour and charged accordingly. The surplus from losses contributes to paying for the transmission company.

Expansion of international interconnectors can be initiated by one or more transmission users who possess import or export contracts and require construction or expansion of an international interconnection from within Argentina to the border. During the amortisation period each transmission user who requested the expansion ("an initiator") will pay an annual charge to the transmission company pro-rata the firm capacity required by its contracts to the total capacity required by all of the initiators.

PJM

PJM uses a nodal pricing system for constraints (but not losses). The firm transmission rights are auctioned off and credited to retailers buying "integrated network service" who effectively pay for the wires. Firm transmission rights can be traded in a secondary market. In 2003, firm transmission rights were paid $499 million of congestion credits against $521 million of firm transmission rights target allocation.

There are no specific charges for generator connections which existed at the time of restructuring. However, new generators and large customers will have to pay for connection to the first point of interconnection. If new generators want "firm access" to retailers, they will have to pay for any upgrading required beyond the point of interconnection. Generators do, however, have the option of only paying for connection and no more, and if there is congestion, then their capacity cannot be sold to meet retailers' capacity obligations.

Transmission charges of the shared network are 100% borne by consuming parties and by parties wheeling out and wheeling through the PJM controlled grid.

[69] The assistance of David Quach in preparing this appendix is gratefully acknowledged.

If a new generator wants to be counted as "unforced capability", which enables it to sell its capacity to retailers to meeting their "unforced capability obligation", then it will have to pay for any reinforcements of the shared network necessary to ensure that the grid can accept its power at all times. Alternatively it can pay nothing towards an upgrade which the PJM considers is necessary, and will not be able to sell its capacity to retailers.

Losses for transmission customers taking network integrated transmission service are calculated on an hourly basis as incurred, while losses for wheeling out or wheeling through are taken as 3% for on-peak hours and 2½% for off-peak hours.

Parties wheeling-out or wheeling-through pay a wheeling charge which is kW related and (like in California) is intended to be broadly similar to the rate for comparable transactions to end-use customers.

New Zealand

New Zealand uses a full nodal pricing with about 200 nodes. A spot price is determined every half-hour.

There are zonal pricing systems in England and Wales, Ontario, Alberta, Texas, and Spain. All these systems have some form of constrained-on and constrained-off payments, except for Alberta which only makes constrained-on payments.

England and Wales

The electricity markets in England and Wales have been governed by New Electricity Trading Arrangements (NETA) since 2001. Although the NETA is not exactly a zonal pricing system, it has the most fundamental characteristic of a zonal market – market participants can transact as though there were no operational congestion and the system operator resolves congestion, in effect, by making constrained-on and constrained-off payments.

NETA replaced a central spot market with bilateral contracting and trading. Under NETA, scheduling entities submit balanced schedules for each half-hour at “gate closure” four hours ahead of the operating half-hour. The system operator manages imbalances and congestion by buying incs and decs in a balancing mechanism, which is equivalent to making constrained-on and constrained-off payments. The system operator recovers the costs of buying incs and decs with an uplift on loads.

Under NETA, generators and loads each pay half of the National Grid Company’s fixed costs through grid access charges. These grid charges vary by location to reflect the long-run marginal cost of the optimal grid to serve generation at each location. New generation and load facilities are required to pay their own direct connection costs, but the National Grid Company pays the costs of “deep” connection assets. If generators or large loads begin operating before the required deep investments are completed, they can be curtailed without compensation.

The costs of deep reinforcements of the network are socialised and allocated using the Investment Cost Related Methodology.

Losses are averaged every half hour across the system and borne 55% by generators and 45% by customers as incurred.

There are two interconnectors to the system. One is a DC interconnector with France, but is currently not open access. The other is the Scottish AC interconnector and is being incorporated into the shared network.**{**tc \l1 "There are two interconnectors to the system:-**}**

Sweden

Svenska Kraftnät makes constrained-on and constrained-off payments to relive congestion. These payments cost $260,000 in 1998. The costs of redispatch are smeared across the national market. It should be noted, however, that Svenska Kraftnät has been known to cut wheeling flows from Germany and Denmark to Norway for technical reasons, a process which also avoids paying for redispatch.

In Sweden, existing users generally pay for lines to connect to Svenska Kraftnät, and Svenska Kraftnät pays for the switchyards, but there is no uniform policy for step-up/-down transformers.

Transmission charges of the shared network are 30% borne on average by generators, 70% borne on average by consuming users.

For new reinforcements of the shared network, Svenska Kraftnät would look to a user to pay for a reinforcement that was mainly for the benefit of a particular user. In practice the policy has not yet been tested.

Ex-ante actual loss factors are calculated for each node for high and low load business days and other times based on averaging forecasts of the marginal losses over all hours in each type of period.

The interconnectors with Norway and Finland are regarded as part of the total market, and a generator that has point access in one country is able to access the whole network. Thus the costs of the interconnecting overhead lines to the borders with Norway and Finland, and Svenska Kraftnät's half share of the undersea cable to Finland, are included as part of the general income that Svenska Kraftnät recovers through its power fee.

There are no physical capacity rights - any trade across a constraint involves the generator selling into its local price area and the customer buying from its local price area.

Norway

Statnett announces the number of pricing zones every six months. Each day, generators and loads submit offers for each hour for the zones of interest. Congestion is relieved within a zone through “counter-buying” by Statnett. If the cost of counter-buying is likely to exceed about $1.5 million over a year and there appears to be enduring changes in transmission capacity or in supply/demand conditions, Statnett is able to increase the number of zones. The costs of redispatch are implicitly smeared across the national market.

In the past, the distribution networks and large energy intensive users have paid for their connections and step-up/-down transformers, but Statnett provides the switchyard.

54% of all Statnett’s income (i.e. wires, losses, congestion) is borne by generators, and 46% by consuming parties. The more or less 50/50 split was the outcome of a political debate and settlement, and the rationale used to shift charges onto consuming users was “equity”.

Statnett pays for shared network upgrades, which it would do provided it can keep the financing within the bounds of its revenue cap.

Ex-ante zonal loss factors are set for six periods each year for each node for working day-time and other periods. The factors are based on the expected average zonal marginal losses. Statnett buys the losses from the spot market as incurred.

There are currently three subsea cables with Jutland which are treated by Statnett as separate businesses and which are largely “closed” for use by the parties to the electricity contracts who pay for the cables, but any spare capacity is made available to trading through NordPool’s spot market and pays for the use. Three more cables with the Netherlands and Germany are planned on a similar basis.

The AC interconnectors with Sweden and Finland are now regarded as part of the total market, are treated as part of the costs of the shared network, and a generator that has point access in one country is able to access the whole network. Their costs are included as part of the general income that Statnett recovers through its access charge.

Finland

Fingrid makes constrained-on and constrained-off payments, costing a few million dollars each year. The costs of redispatch are smeared across the national market.

Parties connected to the grid build their own spurs and provide the transformer.

Transmission charges of the shared network are 100% borne by consuming users.

Fingrid has a stated policy of requiring users to pay for upgrades, but the policy has not yet been tested.

The interconnectors with Sweden and Norway (which is only 50MW) and Fingrid's half share of the undersea cable to Sweden are now regarded as part of the total market, and a generator that has point access in one country is able to access the whole network. Their costs are included as part of the general income that Fingrid recovers through its general charges.

Spain

The system operator makes constrained-on and constrained-off payments to relieve congestion. Constraint costs are averaged across all customers as an uplift.

There are no specific charges for generator connections which existed at the time of restructuring. However, new connections have to pay shallow connection costs. The system operator determines whether or not a spur belongs to the shared network, which determines who pays for the spur. If there is more than one user on a line, then the spur is treated as part of the shared network and its costs are socialised. Alternatively, if there is only one user on the line then the spur will be paid for by the generator or consuming user. The reason for this policy is to reduce the cost borne by a new entrant generator to help encourage development.

Transmission charges of the shared network are 100% borne by consuming users.

The costs of reinforcements will be socialised and borne by consuming users. This policy aims to assist new entrant generators.

The system operator calculates transmission loss factors at each node on an hourly basis, and the intention is eventually to use them for charging scaled marginal losses.

Generators pay no losses; the demand side bidders include losses in their bids for the daily and intra-day market.

The interconnectors in Spain are treated as part of the shared network, and a party that wishes to export has to pay an access charge.

Alberta

A single price is determined for the whole province based on a hypothetical unconstrained dispatch. The system operator manages real-time congestion by making constrained-on payments, but not constrained-off payments.

The Transmission Administrator plans transmission upgrades and awards contracts that effectively subsidise generators to locate where the reduce congestion if this is more cost-effective than new transmission.

Generators and loads each pay half of fixed grid costs through grid access charges. The access charges for generators varies across twelve zones, with higher access charges in zones with excess generation.

Ontario

The Independent Market Operator determines a real-time dispatch and associated nodal prices using a period-by-period security constrained economic dispatch that simultaneously optimises energy and ancillary services, but then settles all spot energy transactions at a single zonal price that clears a hypothetical unconstrained market. The market operator manages congestion by making constrained-on and constrained-off payments.

Texas

ERCOT is primarily a bilateral market with a real-time zonal market used for balancing. Qualified Scheduling Entities submit balanced schedules and ancillary services bids a day ahead, along with balancing energy bids for each of the four zones. The balancing bids are taken in merit order to balance within each zone and to resolve interzonal congestion. The marginal balancing bid in each zone is the zonal real-time price, which is calculated every 15 minutes.

Location-specific incs and decs bids are used to resolve intrazonal congestion, but do not affect the zonal market price. Generators are paid their bid prices for the incs and decs, which is equivalent to making constrained-on and constrained-off payments.

Intrazonal congestion costs are recovered through an uplift paid by all market participants, while interzonal congestion costs are assigned to the Qualified Scheduling Entities scheduling over the constrained interfaces.

California

There are three types of congestion costs: in "inactive zones", "active zones", and across zones and interties.

The congestion in two "inactive zones" (where there is no workably effective competition) are relieved by the ISO calling on units with reliability must-run contracts. The net costs of the units over and above the value of the output they generate is charged to the transmission owner and included in the transmission owner's tariff.

In active zones, where there is a workably competitive generation market, congestion is relieved in two steps: using competitive bids; and calling on units with reliability must-run contracts.

The costs resulting from calling on bids are allocated to scheduling coordinators serving load in the zone, while the costs of calling the reliability must-run contracts are allocated to the transmission owner where the unit is located

The congestion rental resulting from trades across zones and interties is effectively passed to the consuming parties using the grid.

New generators and large customers will have to pay for assets required to connect to the first point of interconnection (called "directly assigned facilities"). For any facilities required beyond the point of interconnection to maintain reliability, the transmission owners had the responsibility of payment, but could ask a generator for an up-front loan to pay for the necessary work.

Transmission charges of the shared network are 100% borne by consuming parties and by parties wheeling out and wheeling through the ISO controlled grid.

A user has to pay for any reinforcement of the shared network necessary to ensure reliability. This is more likely to apply to a consuming load than a generator.

Generation meter multipliers are calculated every hour after the event for each generation point based on the generation input required to serve an increment of load averaged across the system (i.e. no account is taken of the differential losses at different load locations). The scheduling coordinators have to make up the losses or buy them from the imbalance market.

Wheeling access charges are paid by any party scheduling a "wheeling transaction" – wheeling-through the system or wheeling-out of the system. There is no charge for a wheeling-in transaction, which is effectively paid for by end-use customers.

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