Critical assessment of transmission investment decision-making frameworks in the National Electricity Market

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1. Executive Summary

1.1 In the context of its on-going Transmission Frameworks Review (TFR) the AEMC has asked us to undertake a critical assessment of the incentives provided by existing and proposed transmission investment decision-making frameworks in the NEM, based on economic theory and international experience.

1.2 In our assessment we focus on two sets of issues:

- First, whether the Optional Firm Access (OFA) proposal lead to accurate market signals for transmission investment?
- Second, would the incentive mechanisms in the OFA proposal cause investors to respond appropriately, and do they achieve the right balance between incentivising efficiency and minimising risks?

1.3 We summarise our views on each below.

Would the OFA proposal lead to accurate market signals?

1.4 We divide our first question in to two distinct parts:

- On the supply side: does the Long Run Incremental Cost (LRIC) approach proposed under the OFA assess the supplier's (i.e. the transmission company's) costs accurately?
- On the demand side: would the private assessments of benefit that feed into the bids of transmission buyers (generators) be an accurate measure of the public benefits of transmission investment?

Supply-side: LRIC

1.5 The OFA proposal involves the use of a Long Run Incremental Cost (LRIC) methodology. The question is, therefore, whether this methodology would give an accurate assessment of costs. On this we note that the LRIC estimation requires a large number of assumptions. The most critical of these are:

- an assumed growth rate in demand for transmission that would occur absent the specific request under OFA;
- an associated transmission investment profile over time that would be required to maintain predefined security standards; and
- the calculation of the net present value of the cost of that investment, which therefore requires assumptions on capital cost and a discount rate.

1.6 The main advantage of this approach is that it provides an indication to connecting parties through the derived charges where there might be more spare capacity on parts of the network. However, it is critically dependent on the assumptions that feed into it.

1.7 We note one possible disadvantage: in some circumstances, LRIC can in practice approximate a deep connection policy, which leads to the risk of distortions and inefficiency in generator investment decisions. This risk would arise when there is little spare capacity and when there is no growth forecast on the transmission network.

1.8 We note also that the use of LRIC under the OFA proposal would not allow for negative charges, which may be appropriate in some circumstances, where new investment in generation can actually reduce strain on the network and so lead to capex savings.

1.9 The view of the AEMC is that any particular drawback of this approach might be valid for one particular segment in a transmission pathway. However given that, typically, as the overall charge to a generator will be the sum of charges for a number of “segments” of transmission, any distortion is likely to be muted overall.

1.10 This may well be the case. We note that the extensive consultation process used by the AEMC should provide significant information. In any event, as with most policy changes, it is ultimately experience with operation of the regime that will provide a full and final answer. We therefore recommend that the AEMC:

- Monitor the performance of the charging regime to see whether possible theoretical distortions do, in fact, manifest themselves; and
- Manage the market's expectations of the charging regime and embed the possibility of future charging regime modifications.

Demand-side: generator bids

1.11 The question here is whether, under the OFA proposal, generator bids would be an accurate measure of the public benefits of transmission investment.

1.12 As a starting point, we note that the OFA model is, in many respects, very similar to the "standard model" congestion management mechanism used in large parts of North America, based on the use of Locational Marginal Pricing ("LMP") and Financial Transmission Rights ("FTRs").

1.13 Because of the strong similarities between the OFA model and the LMP/FTR paradigm, there are important lessons to be drawn from the debates and analysis that have gone on around LMP/FTR. In particular, the LMP/FTR approach has involved a significant attempt to rely on market signals to stimulate transmission investment, in the form of "merchant transmission".

1.14 There is by now a substantive body of academic and practitioner literature, as well as significant practical experience, with merchant transmission. The literature identifies a number of theoretical problems with merchant investment which are potentially relevant to the OFA proposal. The general conclusion is that "[r]elying primarily on market based 'merchant transmission' investment…is likely to lead to inefficient investment in transmission capacity".[1]

1.15 Some though not all of the problems identified in this literature could apply also under the OFA model. In particular, private decisions can be inefficient in the presence of increasing returns to scale or "lumpy" investments; and generators' incentives to demand additional access rights may be too weak, because some of the benefits of additional interconnection accrue to consumers not to generators.

1.16 We conclude that, at least in theory, there may be the potential risk of incentivising under-investment under the OFA proposal.

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[1] Joskow, Paul. "Lessons learned from electricity market liberalization." *The Energy Journal* 29.2 (2008): 9-42.

1.17 However, we note that there are likely also countervailing incentives, particularly in Australia, where it appears that over-investment rather than under-investment is the real-world concern. There are also possible modifications to the OFA proposal that could help address the concern.

1.18 Finally, we note that relying on "market-based" signals inevitably leads to concerns and analysis of potential "market failures". But this risk must be compared not to a theoretically ideal outcome, but to reality and in particular to another more regulated regime operating in practice and therefore the risks of "regulatory failure".

The incentive mechanisms in the OFA proposal

1.19 In relation to our second question, we address three issues concerning the incentives that the OFA system would give to transmission investment decision-makers:

- As a starting point, how low/high-powered are the incentives? In other words, how much do the regulated companies revenues/profits depend on its performance?
- Second, how sensitive is the regulated company to such incentives? In particular, to what extent should one expect it to respond to financial incentives? This may be particularly relevant if (for example) it is a state-owned company whose senior management are much more sensitive to political approval than to the company's financial performance.
- Finally, how strong should the incentives be? Is it desirable to give strong incentives via a market-based scheme, or could that lead to undesirable risk allocations or distortions in behaviour?

How high or low-powered are the incentives under the OFA proposal?

1.20 At highest level, the nature of these incentives will necessarily involve a combination of factors. First there is the degree of TNSP exposure to cost over or under-runs. We understand that the current AEMC proposal would be relatively low-powered in this regard. At most the TNSP would be exposed to 100% of the difference between its actual costs and the LRIC estimate, but only until the end of the current regulatory period. Thus consumers would bear most of the risk of over-runs. We note that this approach might distort the TNSP's decision-making.

1.21 Second there is the question of penalties for failing to provide firm access. The proposed Firm Access Standards already provide for a significant element of TNSP discretion in deciding whether or not it has breached Firm Access Standards, albeit subject to regulatory oversight. We caution against allowing too much latitude to TNSPs, so as to avoid any risk that the supposedly firm access rights become only “optionally firm”, i.e., effectively interruptible at the discretion of the TNSP.

1.22 That aside, we understand that the AEMC’s current proposals involve at least two and possibly four sets of penalty regimes for failure to provide firm access once committed to do so, summarised by the AEMC in the table below.

	Length of time	TNSP Exposure / Downside	TNSP Upside
Long-term incremental access	first 5 years of access	100%, subject to caps	100% of revenue (based on LRIC), retain difference between LRIC and actual cost
Timely release of access	until access is released	governed by permits	early delivery can be sold as short-term access
Operational	following first 5 years of access	X%, subject to caps	zero
Short-term access	for quarter short-term access is provided	100%, no caps	100% of revenue (from auction) for relevant quarter

1.23 Obviously the extent to which these proposals are high or low-powered depends almost entirely on the level of the caps, and the size of the X% parameter (i.e., the level of exposure to settlement shortfalls after the first five years of access).

How sensitive is the regulated company to such incentives?

1.24 One should not automatically assume that the regulated company will respond to financial incentives, particularly if it is state-owned. Like other companies, a state-owned company is typically responsive to its owner and to other stakeholders such as labour unions and/or entrenched management. It therefore has a complex set of objectives including not only financial performance but also a number of other criteria.

1.25 For a state-owned transmission company those other criteria are likely to include security of supply, which in our experience is a very major focus for politicians[2]; and the impact of its operations on politically influential constituencies, including generators (especially if also state-owned) and large industrial consumers.[3]

1.26 The same considerations are also relevant to a lesser degree in the case of privately owned transmission companies. Regulated companies are in the long-run highly dependent on political favour, and perceive themselves to be so.

1.27 In summary therefore, a transmission company may be less responsive to financial incentives than might be expected in other settings, because:

- The consequences of financial penalties may be less of a concern because of a "soft budget constraint".[4]
- Out-performing a regulator's expectations may be less attractive than it appears. The company may expect that any gains will be removed later.
- In any case, the financial performance of the company may be only one of a number of criteria that guide the decisions of senior management.

1.28 We would therefore expect the effect of financial incentives on regulated transmission companies to be somewhat dampened.

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2 In that regard of course politicians to some extent simply reflect public concerns.

3 For electricity distribution companies one would often add employment to this list.

4 The concept of "soft budget constraint" was first developed in the context of socialist economies, but has since been extended to cover a wide range of situations where companies are insensitive to financial incentives. See Kornai, Janos, Eric Maskin, and Gerard Roland. "Understanding the soft budget constraint." *Journal of economic literature* 41.4 (2003): 1095-1136.

How strong should the incentives be?

1.29 At the very highest level, one can conceptualise the issues around the design of a transmission investment decision-making framework by reference to the concept of multi-task principal-agent analysis.

1.30 Multi-task principal-agent problems arise where the Principal requires the Agent to perform multiple tasks. For example, an employer might require the worker to serve customers quickly, but also to provide a high level of service (smile nicely, be polite and charming, etc).

1.31 A key point in relation to multiple task situations is that typically *one can measure performance better in one activity than in another*. For example, it is very easy to measure how many customers the worker serves, but very difficult to measure the quality of service he/she provides.

1.32 In those circumstances, a fundamental insight from the literature on multi-task principal-agent problems is that "the desirability of providing incentives for any one activity decreases with the difficulty of measuring performance in any other activities that make competing demands on the agent's time and attention".[5] In the example above, the fast-food outlet can give the worker a strong incentive to serve as many customers as possible, but it cannot give him/her a strong incentive to provide a high level of service, because of the measurement problem. Providing a strong incentive to serve as many customers as possible is therefore less desirable if the outlet also cares about quality of service.

Application to transmission investment

1.33 One can think of transmission investment in this framework. The Principal is the regulator/policy-maker (acting on behalf of consumers). The Agent is the transmission owner (or perhaps its senior management).

1.34 The Principal wishes the transmission owner to perform multiple tasks, and it is clear that performance is more easily measured on some dimensions than on others:

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5 Holmstrom & Milgrom (1992), p.26.

- Invest efficiently, i.e, build transmission infrastructure that maximises consumer welfare, taking into account reliability and economic benefits;
- Maintain the transmission infrastructure, meet reliability standards, and maximise the availability of capacity;
- Minimise its total costs.

1.35 Second, different "incentive frameworks" correspond to lower or higher-powered incentives:

- A non-profit transmission owner or transmission investment decision-maker faces flat (low-powered) incentives. In theory the incentives might sound as though they are completely flat, although in practice it is likely that there is some, relatively weak, incentive to be more profitable and/or efficient.;
- A for-profit transmission owner faces medium-powered incentives in a regulatory regime that tends towards a "cost-plus" approach. A pure cost-plus approach might in principle be completely flat, but again in practice there will be some level of incentive, and typically it will be stronger than for a non-profit;
- A for-profit transmission owner faces high-powered incentives in a regulatory regime that is based more on "RPI-X" or "incentive regulation" approaches, where its profitability is significantly enhanced when it manages to cut costs, and also if other aspects of the regulatory regime provide strong financial rewards/penalties.

1.36 Some of the transmission owner's outputs are easier to measure than others. For example, it is very easy to measure how much the transmission owner spends, but arguably more difficult to assess the transmission owner's performance with regards to security of supply.

1.37 A key point therefore is that *a regulator who wishes to provide strong financial incentives that focus the transmission owner very strongly on cost minimisation and profit maximisation must make sure that it has also put in place appropriate indicators and incentives to guard against under-performance on security of supply*.

1.38 A key issue therefore is whether or not it is possible to identify good measures of performance in ensuring the sustainability to transmission network performance, what it refers to above as “good leading reliability indicators”. This has been the subject of considerable debate in the UK. In the context of the most recent electricity transmission price control, Ofgem has developed some key output metrics to which financial incentives are directly attached. These metrics relate to:

- Reliability – in which the primary output that is measured is based on energy not served.
- Customer satisfaction survey – in which stakeholder views are canvassed and influence the amount of revenue that the company is allowed to recover from customers.
- Environmental – some of NG’s revenue is also related to environmental factors such as emissions.

1.39 In addition, Ofgem has developed a basket of Network Output Measures (NOMs) that NG must report on annually, and to which financial incentives are attached. These relate to technical aspects of the TO assets such as criticality, average circuit unreliability, replacement priorities, system unavailability etc.

Conclusions

1.40 Overall therefore our conclusions are that:

- First, the overall strength of the incentive framework for the TNSPs delivered by the new regime is relatively low-powered, although the parameters of some aspects of the regime are still to be agreed. Nonetheless, it seems that the regulator intends to put some meaningful financial incentives in place.
- Second, we have also noted that high-powered incentives on regulated transmission businesses come with some risks - in that there is the possibility that the regulated companies focus on delivery of those parameters on which they are measured at the expense of performance on metrics elsewhere. In other jurisdictions, this concern – together with a desire to place greater incentives on regulated transmission businesses, has led to the development of a wide range of measures that aim to encourage delivery of security of supply and reliability while still encouraging efficient investment.

- In a transmission business there are strong countervailing incentives. The culture of a transmission business is one defined by electrical engineers with a very strong focus on reliability. As noted by the Productivity Commission, absent financial incentives the outcome appears to be too much rather than too little reliability.

1.41 Overall therefore, concerns about over-reliance on incentives should be mitigated by the two safeguards of monitoring a wide range of performance indicators and the inherent "culture of the transmission business. One would not want to rely on the "engineering culture" alone: that could be changed or over-rode by strong, commercially-minded senior management. However, that would be very difficult in the face of careful, well-designed and implemented regulation to ensure continued attention to security of supply (including regulation to ensure transparency in TNSP operation).

2. Introduction

2.1 In the context of its on-going Transmission Frameworks Review (TFR) the AEMC has asked us to undertake a critical assessment of the incentives provided by existing and proposed transmission investment decision-making frameworks in the NEM, based on economic theory and international experience.

2.2 We have reviewed the AEMC's proposals as laid out in its Second Interim report,[6] along with related documents. In our view, there are two sets of relevant issues. First is the question of *market signals for transmission investment*. The Optional Firm Access (OFA) proposal would involve generators providing market signals to transmission investment decision makers, in the form of "bids" for Firm Access Rights ("FARs"). It is therefore important to assess how accurate those signals are, i.e., to what extent the implied pattern of transmission investment represents an optimal investment programme.

2.3 Since optimal investment can be equated with a cost-benefit criterion, this question can itself be unpacked into two parts:

- Does the OFA proposal assess costs accurately?
- Would the private assessments of benefit that feed into generator bids be an accurate measure of the public benefits of transmission investment?

2.4 In this report we discuss both points, focusing on the Long Run Incremental Cost (LRIC) based cost assessment proposal that underlies OFA, and on some well-known issues around market-based investment in transmission.

2.5 The second set of issues we address concerns *incentives for transmission investment*. If the OFA proposal does provide accurate signals, will the incentive mechanisms it provides cause investors to respond appropriately, and do they achieve the right balance between incentivising efficiency and minimising risks? Possible risks around a more market-based approach to transmission investment include the risk of:

[6] AEMC, *Second Interim Report, Transmission Frameworks Review*, 15 August 2012.

- excessive or windfall profits;
- that the transmission company is exposed to too much risk, leading to a higher required return (potentially an additional cost to consumers, if those risks are unnecessary or could be allocated more efficiently); and
- that the incentive regime leads to under-investment in long-term security of supply.

2.6 We discuss these risks, focusing in particular on the last point, which has recently arisen in the Productivity Commission's analysis of the Australian transmission sector.[7]

2.7 The rest of this report is structured as follows:

- Section 3 provides a high-level summary of the OFA proposal. We take it that the reader is already familiar with the AEMC's proposal and the debate surrounding it.[8] Our purpose here is simply to highlight the key features that we will proceed to analyse.
- Section 4 discusses the first of the two questions above, i.e., the issue of market signals.
- Section 5 discusses the second question, i.e., the issue of incentives for transmission investment; and
- Section 5 briefly summarises our conclusions.

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7 "Electricity Networks Regulatory Frameworks", Productivity Commission Draft Report, October 2012

8 If not, the starting point would be the AEMC's Second Interim Report cited above.

3. Background

3.1 In this section we provide a high level summary of the key features of the transmission frameworks we are reviewing. We discuss, in turn, the OFA proposals before then going on to discuss the transmission planning investment cycle.

The OFA proposal

3.2 The OFA proposal has three key elements:

- First, a methodology for estimating the cost of transmission investments, the Long Run Incremental Cost (LRIC) approach.
- Second, a methodology or process to identify investments that have net benefits (i.e. whose benefits are greater than the costs as estimated via the LRIC approach). That methodology is the sale of (financially) firm long-term access rights, at a price set by the LRIC methodology.
- Third, a process to trigger investment, i.e., to incentivise transmission investment decision-makers to make the investments identified (via the second step) as having a net benefit, and to do so efficiently (i.e., at least cost).

3.3 The process to trigger investment involves rules designed to ensure that investment decisions respond to the signals arising from sale of firm access rights. A key element of these incentives is the existence of penalties that would be imposed for failure to deliver the firm access to rights-holders.

3.4 In principle the incentives would mean that transmission investment planning will be undertaken so as to ensure that the TNSP is always able to deliver the firm access it has sold (i.e., meet the Firm Access Standards[9]), as well as meeting its reliability requirements. The sale of new firm capacity would therefore necessitate a review and potential upgrade of investment plans so as to be sure of meeting those twin criteria.

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9 The Firm Access Standard is the lowest level of service quality that the TNSP is permitted to provide.

3.5 To price the firm access rights the TNSP would need to: (1) design a baseline expansion plan for transmission investment; (2) design an adjusted expansion plan, to take into account the firm access request; (3) the LRIC is the difference in NPV of these two plans. Failure to deliver firm access would result in financial penalties falling on the TNSPs. We describe the proposed penalty regime in more detail later in this report, while noting that at present it is very much open to further debate.

Transmission investment decision-making

3.6 In this subsection we briefly describe the three different sets of arrangements currently in place in the member States of the NEM for the purposes of planning transmission investment:

- First, there is a private, for-profit TNSP that makes transmission decision investments in South Australia. Regulatory oversight is provided by the Australian Energy Regulator (AER), although a not for profit body - the Australian Energy Market Operator (AEMO) - advises the AER as to the appropriateness of the TNSP's revenue proposal.
- Second, a state-owned, albeit still theoretically "for-profit" TNSP, that makes transmission decision investments. This operates in New South Wales, Queensland and Tasmania. Regulatory oversight is provided by the AER (and we understand that, in contrast to the SA case, there is no specific role for the AEMO).
- In Victoria, AEMO makes investment decisions and "procures" new investment. We understand that in practice the new investment is almost always procured from the incumbent (privately owned) TNSP.

4. Would the OFA proposal lead to accurate market signals?

4.1 We are aware that there has been extensive debate around many of the issues involved in electricity transmission investment, including input from a number of academics and consultants. In this paper therefore we do not wish to discuss further the many detailed issues that have already been the subject of considerable analysis in Australia. We do however provide some high level thoughts on a few fundamental questions arising from the OFA proposal, as indicated above:

- Does the LRIC methodology proposed as part of the OFA model assess costs accurately? (In other words, "how well does the supply side of the model work?")
- Would the private assessments of benefit that feed into generator bids under the OFA model be an accurate measure of the public benefits of transmission investment? (In other words, "how well does the demand side of the model work?")

4.2 Below we address each in turn (and include some additional comments on the LRIC methodology).

Does the LRIC methodology proposed as part of the OFA model assess costs accurately?

4.3 The OFA proposal involves some variant of the LRIC methodology to reflect the cost of incremental transmission. The broad principle is that the charge for any particular user will reflect the difference between two states of the world:

- First, a *baseline expansion plan* for transmission is derived. The net present value of the cost, in terms of investment in transmission, of meeting this expansion plan is then calculated. This is known as the baseline cost.
- Second, following a request for additional transmission capacity, an *adjusted expansion plan* is derived. The net present value of the cost of meeting this new profile of transmission build – the adjusted cost – is then calculated.

4.4 The difference between the adjusted cost and the baseline cost is then calculated to derive what is termed the LRIC of transmission.

4.5 This approach to network charging has a long history, dating back to the 1960s[10] and was much debated in the latter part of the 2000s decade in Great Britain in the context of electricity distribution charges[11]. The approach suggested by the AEMC appears close to this type of approach.

4.6 As a first point, we would note that the LRIC estimation requires a large number of assumptions. The most critical of these are:

- An assumed growth in demand for transmission that would occur absent the specific request under OFA;
- An associated transmission investment profile over time that would be required to maintain predefined security standards. This therefore requires calculation of the volume of spare capacity and then the types of investment (including the sizing of transmission investment) required to meet the forecast demand for transmission;
- The calculation of the net present value of the cost of that investment, which therefore requires assumptions on capital cost and a discount rate (which is assumed to be the TNSP's regulated cost of capital).

4.7 The main advantage of this approach is that it provides an indication to connecting parties through the derived charges where there might be more spare capacity on parts of the network. However, it is critically dependent on the assumptions that feed into it.

4.8 As is recognized by the AEMC in the August 2012 Staff paper, depending on the assumptions used the methodology may approximate a deep connection policy. This will be when there is little spare capacity and when there is no growth forecast on the transmission network. Put another way, the connecting party would pay for all of the costs of the transmission reinforcement (sized as determined by the transmission network owner) – even if some (or a lot) of the investment is not required by the connecting party.

10 See, for example, Ralph Turvey, 1968. "*Peak-Load Pricing*," Journal of Political Economy, University of Chicago Press, vol. 76, pages 101.

11 See for example, "*Delivering the electricity distribution structure of charges project: decision on extra high voltage charging and governance arrangements*", Ofgem, 21 July 2009.

4.9 A well-known problem with deep connection policy is that it provides a disincentive for connecting parties to trigger an investment. Rather, there is an incentive to wait for other parties to trigger the investment. Everything else being equal, therefore, this will lead participants to under-demand transmission investment. This issue has been much discussed in the context of electricity distribution charges in GB[12]. A proposed fix was to assume a fixed growth rate of 1%, with a notable dis-advantage that this reduces the cost reflectivity of the price signal.

4.10 In passing, we note that the charging policy is set so that LRIC charges are constrained not to be negative. Negative charges might theoretically occur where generator siting decisions results in the deferral of transmission investment. Instead, it is assumed that a generator might be able to enter into separate agreements with the TNSP (in part to guarantee availability) – in turn ensuring that the benefits of siting decisions might be appropriately captured. To the extent that these types of ad hoc agreements are inherently more uncertain and less transparent to a generator when making a siting decision, it may be the case that this policy might result in higher charges than would otherwise be the case and might, everything else being equal, act as a deterrent for generators to site near demand.[13] Hence it would seem desirable if the methodology could, over time, be developed to incorporate the benefits of siting decisions rather than just the costs.[14]

4.11 More generally, the assumptions used to inform the charges derived will inevitably be the focus of much scrutiny by all market participants in coming years, as clearly they will impact materially on the level of charges and therefore the level of demand for transmission.

4.12 One concern in this regard is that it will often be very difficult to judge whether the assumptions made are indeed the appropriate ones. In this respect there is likely to be an asymmetry of information between the TNSP and all other stakeholders. This might allow transmission investment decision makers to adjust the assumptions in a way that allows a more favourable outcome from its perspective.

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12 See for example '*Decision Document: Delivering the electricity distribution structure of charges project*', Ofgem, 1 October 2008 where ii notes that the LRIC Model "*produces excessive charges under conditions of high utilisation and low growth rates*" (Ref 135/08), Section 2.55.

13 We note that transmission charges in GB are, in certain locations negative.

14 To some extent the effects of an individual "incorrect" charge may well be diluted by the fact that typically the overall charge for a generator will be the summation of a number of separately derived charges for each element of a transmission upgrade.

4.13 The remedy to this proposed by the AEMC is to allow AEMO as National Transmission Planner an enhanced role in both checking and providing the assumptions used in the derivation of charges. A further approach would be to have some form of stakeholder involvement that meets regularly to scrutinize the assumptions used. This may provide for an additional check on how the assumptions are derived. In the experience of the GB market, this has been seen to be a relatively effective check on the (equivalent of the) TNSPs[15].

4.14 Overall, it is clear that the AEMC have considered carefully a range of charging options for transmission, recognising the inevitable trade-offs of a given approach. Its view is that any particular drawback of this approach (for example, the possibility in certain extreme examples of providing a deep connection signal or not allowing for the possibility of negative charges) might be valid for one particular segment in a transmission pathway. However given that, typically, as the overall charge to a generator will be the sum of charges for a number of "segments" of transmission, that any distortion is likely to be muted overall.

4.15 This may well be the case. Testing it would require a detailed empirical analysis that lies well outside the scope of this paper. We note that the extensive consultation process used by the AEMC should provide significant information. In any event, as with most policy changes, it is ultimately experience with operation of the regime that will provide a full and final answer. We therefore make two further recommendations:

- The first, which we suspect the AEMC will do anyway, is to monitor the performance of the charging regime to see whether possible theoretical distortions do, in fact, manifest themselves; and
- Second, manage the market's expectations of the charging regime and embed the possibility of future charging regime modifications. The history of the GB transmission charging regime is that the "winners" and "losers" created by changing the methodology for deriving transmission charges can often make it practically difficult to implement changes.

15 For example, the discussions on the Review of Security and Quality Supply Standard by National Grid and the other TOs were subject to extensive stakeholder involvement that resulted in significantly more change in the approach than was originally envisaged (or wanted) by the TNSPs.

Would generator bids be an accurate measure of the public benefits of transmission investment?

4.16 As a starting point, we note that the OFA model is in many respects very similar to the “standard model” congestion management mechanism used in large parts of North America, based on the use of Locational Marginal Pricing (“LMP”) and Financial Transmission Rights (“FTRs”). A full description and extensive discussion of this model can be found in the academic and practitioner literature. Here we simply note the main parallels between the two models, as well as certain differences.

4.17 First, the holder of Firm Access Rights (“FARs”) under the OFA model is essentially equivalent to a generator in the export-constrained location that holds FTRs from its location to the Regional Reference Node (RRN). In the LMP/FTR world this generator would receive the locational price for its actual dispatch plus the locational price difference (the “congestion shadow price”) times the number of FTRs it holds over the constraint.

4.18 For FAR holders, the main differences between the two models are that under the OFA model:

- The generator in effect receives the locational price difference, but only if it is positive (in effect, it holds an “FTR option”).
- The generator’s holdings of FARs is limited to the size of its registered capacity (and only generators can hold FARs).
- As discussed later, FARs as currently proposed are less financially firm than FTRs as implemented in north America: under the OFA proposal, when the TNSP is not able to provide sufficient capacity to match all issues FARs, it can under some circumstances scale them back.

4.19 Second, under OFA, generators that do not hold FARs are essentially equivalent to generators in the LMP/FTR who do not hold FTRs, and therefore simply receive their locational price (rather than the RRN price). One difference however is that when there is surplus transmission capacity, the settlement surplus is allocated to generators without FARs, whereas conventionally any settlement surpluses are paid into a fund and used to fund FTR payouts during periods of transmission shortfall.

Lessons from the "merchant transmission debate"

4.20 Because of the strong similarities between the OFA model and the LMP/FTR paradigm, there are important lessons to be drawn from the debates and analysis that have gone on around LMP/FTR. In particular, the LMP/FTR approach has involved a significant attempt to rely on market signals to stimulate transmission investment, in the form of "merchant transmission". There is by now a substantive body of academic and practitioner literature, as well as significant practical experience, with merchant transmission.[16]

4.21 The literature identifies a number of theoretical problems with merchant investment which are potentially relevant to the OFA proposal. The general conclusion is that "[r]elying primarily on market based 'merchant transmission' investment, that is where new transmission investments must be fully supported by congestion rents (the difference in locational prices times the capacity of a new link) is likely to lead to inefficient investment in transmission capacity".[17]

4.22 Some though not all of the problems identified in this literature could apply also under the OFA model. We focus on two such problems:

- Private decisions can be inefficient in the presence of increasing returns to scale. An extreme version of this is when investments are "lumpy", as is the norm in transmission.[18]
- Generators' incentives to demand additional access rights may be too weak, because some of the benefits of additional interconnection accrue to consumers not to generators.

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[16] The most important paper in the purely academic literature is Joskow, P. L. and J. Tirole. (2005). "Merchant Transmission Investment." Journal of Industrial Economics, 53(2): 233-264. For a very clear exposition of some of the key concepts, with specific application to Australia, see Joshua Gans and Stephen King, "Options for Electricity Transmission Regulation in Australia," *Australian Economic Review*, Vol.33, No. 2, June 2000, pp.145-161.

[17] Joskow, Paul. "Lessons learned from electricity market liberalization." *The Energy Journal* 29.2 (2008): 9-42.

[18] To see why lumpiness can be thought of as an extreme version of increasing returns to scale (i.e. decreasing marginal cost), note that if it is only possible to create new transmission capacity in (say) lumps of 500MW, then the cost of providing (say) 100MW is the same as the cost of providing 500MW (equivalently, the cost of the last 400MW is zero).

Increasing returns to scale

4.23 As a simple example, suppose that there are two parties who are both considering building identical 500MW power stations at two locations very close to each other. The output would be sold to consumers at a more distant location, and doing so would require a transmission upgrade. Suppose that (i) the cost to the TNSP of this upgrade is based on a lumpy investment of 1000MW; (ii) if one party alone has to bear that cost then it is not worth doing (i.e., the total investment in generation and transmission has negative net benefit); but (iii) it is efficient to build the two power stations and incur the cost for the transmission. Then if the TNSP sets the LRIC based on a baseline of no investment, no-one invests (which, as we have defined the problem would lead to an inefficient outcome). In essence, this is a restatement of the problem of a deep connection policy that occurs when there is limited spare capacity and low growth that we discussed earlier.

4.24 Overall, therefore:

- Because the outcome depends on the choice of baseline, it seems that the decision is in effect made by the TNSP - at least as much as by the market. This is why the arrangements governing how assumptions are derived – and in particular those in relation to spare capacity and growth – will be important. Transparency of the decision making process and buy in from a wide range of stakeholders will be critical if the charging regime is not to become a source of on-going (potentially costly and litigious) friction between sets of stakeholders.
- One could equally imagine that it is in fact inefficient for the two power stations to get built. If the TNSP sets the LRIC based on a baseline of one or both being built, then they will get built even though it is inefficient.

4.25 This kind of coordination problem is probably best resolved through some kind of bargaining. The efficiency of bargaining depends on a number of factors. Economic theory and practical experience both suggest that well-informed parties should under plausible assumptions be able to negotiate an efficient outcome, and we believe that some UK experience with similar schemes for natural gas transmission provides a precedent for positive outcomes from an informal bargaining process. We understand that the AEMC is proposing a mechanism of "grouped access procurement" that would facilitate such bargaining. However, we note also the caveat that information asymmetries can, both in theory and in practice, lead to delays and inefficient outcomes in bargaining: there is no “silver bullet”.

Inability to capture benefits to consumers

4.26 In the OFA model, the capacity is determined by the generators on the export side of the constraint requesting additional FTRs. The optimal quantity of the capacity will depend on the extent to which these generators can internalise the benefits from the capacity accrued to all participants on both sides of the constraint. In theory this could lead to under-investment (just as in the merchant transmission model, where the amount of capacity is sub-optimal since it is determined by the congestion rent and does not take into account the benefits to the generators and customers on both sides of the constraint).

4.27 As a simple example, imagine that there are generators in area A,[19] each of whom has marginal cost of 20 $/MWh, and also generators in area B, each of whom has marginal cost of 30 $/MWh.[20] Suppose also that there is sufficient capacity in area A to meet the load of both areas combined. If transmission is sufficiently inexpensive, the efficient outcome would be to build enough transmission capacity between the areas for all of the load to be met by the area A generators. In that case the price will be 20 $/MWh in both regions. However, the area A generators will not want to buy that much transmission, because in that case they will end up selling at cost. They will prefer to buy enough transmission to sell some power at 30 $/MWh.

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19 At the level of abstraction of this example, an "area" could be a region or a part of a region (using "region" to refer to the regions of the NEM). However, under the OFA proposal there are some important differences between the two cases, notably that the price faced by consumers is uniform within in a single region. In either case however, a reduction in the price generators receive for sales to area B would benefit consumers.

20 Note therefore that the higher price in area B is not a result of lower levels of competition. The benefit from increasing interconnection between the two areas is not a "competition benefit" but a straightforward efficiency gain as lower priced generation replaces higher priced.

4.28 Of course this example itself is unrealistic. It is intended to be illustrative of a general point, one that is well-established in the economic literature cited earlier, and that we believe follows a simple economic logic: in deciding how much transmission capacity to commission via OFA bids, a generator will in general be aware that the more it builds, the less each of transmission built will be worth to it, because of the lower price difference between the two sides of the link.

4.29 It might be argued that this outcome is a result of a lack of competition in generation, and that in a perfectly competitive market, generators in area A would continue to purchase FARs until the price they received fell to 20 $/MWh. However, the level of competition that argument relies on appears unrealistic: it requires a market where competition is so atomistic that each generator acts as a pure “price taker”, ignoring the effect of its FAR purchases on price. In our opinion this may be unrealistic—at the very least, one could not safely assume such an outcome.

4.30 Moreover, actual experience with merchant investment confirms the reality of the under-investment problem: “the dream that merchant investors would come forward to make all efficient investments in response to congestion has not been matched by reality. As of the end of 2003 no merchant transmission network investments were made in PJM (or in New England or New York), as congestion costs steadily rose.”[21]

4.31 Moreover, this example has nothing to do with any “competition benefit”. There are many reasons other than lack of competition why imports from region A may be cheaper than indigenous generation in region B.

Conclusions

4.32 Our conclusions on this point are as follows. First, the arguments in the economic literature are (unsurprisingly) theoretically correct. On that basis, we believe that, at least in theory, there may be the potential risk of incentivising under-investment under the OFA proposal.

4.33 However, we note that there are likely also countervailing incentives, particularly in Australia, where it appears that over-investment rather than under-investment is the real-world concern (see e.g. Productivity Commission, pp.15-16). That does not surprise us, since typically infrastructure companies like to build infrastructure, unless they have strong incentives not to.

21 Joskow, Paul L. "Transmission policy in the United States." *Utilities Policy* 13.2 (2005): 95-115.

4.34 Assessing the relative strength of these potentially conflicting incentives requires a more in-depth view of the Australian market and regulatory environment. If there is a concern, then one possibility would be to adopt an approach like that used for natural gas transmission in GB, where National Grid builds new entry capacity provided it has firm commitments whose financial value comprises 50% (in NPV) of the estimated cost. However, one has to recognise that such an approach would place additional risk on consumers, and might also lead to free riding.

4.35 Finally, we note and fully endorse the point made by Stephen Littlechild in his 2011 piece on merchant transmission (which contains detailed discussion of Australian experience), that the risks of "market failure" have to be compared not to a theoretically ideal outcome, but to reality and in particular to the risks of "regulatory failure".[22]

[22] Stephen Littlechild, Journal of Regulatory Economics, December 2012, Volume 42, Issue 3, pp. 308-335, *Merchant and regulated transmission: theory, evidence and policy*.

5. Incentives acting on the transmission investment decision-maker

5.1 In the preceding section we have reviewed the accuracy of the signals that the OFA system provides. Here we focus on the incentives it would give to transmission investment decision-makers. We have identified three relevant questions:

- As a starting point, how low/high-powered are the incentives? In other words, how much do the regulated companies revenues/profits depend on its performance?
- How sensitive is the regulated company to such incentives? In particular, to what extent should one expect it to respond to financial incentives? This may be particularly relevant if (for example) it is a state-owned company whose senior management are much more sensitive to political approval than to the company's financial performance.
- How strong should the incentives be? Is it desirable to give strong incentives via a market-based scheme, or could that lead to undesirable risk allocations or distortions in behaviour?

5.2 Below we discuss each question in turn.

How high or low-powered are the incentives under the OFA proposal?

5.3 We understand that the design of the incentive regime for transmission investments is still open at this stage, and that existing proposals are in the nature of a "strawman". We will describe and discuss these proposals on that basis.

5.4 At highest level, the nature of these incentives will necessarily involve a combination of factors. First there is the degree of TNSP exposure to cost over or under-runs. That issue arises in any form of transmission price regulation. In theory, optimal incentive schemes generally involve some degree of sharing of under/over-runs.[23] We understand that the current AEMC proposal would be relatively low-powered in this regard. At most the TNSP would be exposed to 100% of the difference between its actual costs and the LRIC estimate, but only until the

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23 See Laffont, Jean-Jacques, and Jean Tirole. "Using cost observation to regulate firms." *The Journal of Political Economy* (1986): 614-641.

end of the current regulatory period. Thus consumers would bear most of the risk of over-runs.

5.5 At the margin, it is worth noting that this approach might distort the TNSP's decision-making, as it will trade off the potential benefit of delivering the "lowest cost" capex solution (and hence gaining relative to the LRIC set amount allowed in the first regulatory period) with the benefit of a higher cost approach that would then be incorporated into the RAB over the remaining life of the asset. This is a well-known problem in regulation more generally and serves to demonstrate the need for the regulator to maintain clear oversight of TNSP capital expenditure.

5.6 Second there is the question of penalties for failing to provide firm access. One immediate observation is that the proposed Firm Access Standards already provide for a significant element of TNSP discretion in deciding whether or not it has breached Firm Access Standards, albeit subject to regulatory oversight. In particular, the arrangements that determine when the TNSP is deemed to be operating outside of Normal Operating Conditions will need to be carefully established so as to limit the opportunity for the TNSPs to provide lower access than the capacity paid for by generators. While recognising that some such derogations may be required, we would advise caution. Given the asymmetry of information between TNSP and regulator, there is an inevitable risk that the supposedly firm access rights become only "optionally firm", i.e., effectively interruptible at the discretion of the TNSP. This would undermine the whole basis of the OFA proposal.

5.7 That aside, we understand that the AEMC's current proposals involve two sets of penalty regimes for failure to provide firm access once committed to do so:

- **Operational incentive scheme**. A regime that would apply after the first five years, where the TNSP was exposed to some proportion of settlement shortfalls (less than 100%, although the exact percentage remains open at this stage).
- **Short-term access incentive scheme**. TNSPs would be 100% exposed to any shortfalls that result from not providing short-term access, and no cap would apply.

5.8 We further understand that the AEMC is also considering two possible additional incentive schemes:

- **Timely release of access incentive scheme**. Essentially the TNSP would be allowed to delay release of firm access. It would need to justify any delays to the AER. Failure to justify them to the satisfaction of the AER would result in the TNSP being responsible for paying compensation to the generator, for access not being granted.

- **Long-term incremental access incentive scheme**. The TNSP would be exposed to 100% of settlement shortfalls for the first 5 years following when access is contracted for, but subject to certain caps.

These incentives are summarised by the AEMC in the table reproduced below.

	Length of time	TNSP Exposure / Downside	TNSP Upside
Long-term incremental access	first 5 years of access	100%, subject to caps	100% of revenue (based on LRIC), retain difference between LRIC and actual cost
Timely release of access	until access is released	governed by permits	early delivery can be sold as short-term access
Operational	following first 5 years of access	X%, subject to caps	zero
Short-term access	for quarter short-term access is provided	100%, no caps	100% of revenue (from auction) for relevant quarter

5.9 Obviously the extent to which these proposals are high or low-powered depends almost entirely on the level of the caps, and the size of the X% parameter (i.e., the level of exposure to settlement shortfalls after the first five years of access). We understand that there is currently vigorous discussion of these questions. Our own views will be developed below.

How sensitive is the regulated company to such incentives?

5.10 As noted above, one should not automatically assume that the regulated company will respond to financial incentives, particularly if it is state-owned. Like other companies, a state-owned company is typically responsive to its owner (although other stakeholders such as labour unions and/or entrenched management may also be powerful influences). It therefore has a complex set of objectives including not only financial performance but also a number of other criteria.

5.11 For a state-owned transmission company those other criteria are likely to include security of supply, which in our experience is a very major focus for politicians[24]; and the impact of its operations on politically influential constituencies, including generators (especially if also state-owned) and large industrial consumers.[25]

5.12 The same considerations are also relevant to a lesser degree in the case of privately owned transmission companies. Regulated companies are in the long-run highly dependent on political favour, and perceive themselves to be so.

5.13 In summary therefore, a transmission company may be less responsive to financial incentives than might be expected in other settings, because:

- The consequences of financial penalties may be less of a concern because of a "soft budget constraint".[26] For example, the company may believe that it will be bailed out if it is perceived to have spent above its allowed revenues in order to preserve security of supply. The bailout could take many forms (e.g., preferential tax treatment, or a more generous regulatory settlement in the future).
- Out-performing a regulator's expectations may be less attractive than it appears. The company may expect that any gains will be removed later, particularly if they are seen to have been earned through endangering security of supply, or are regarded as being excessive. Gains may be removed through taxation (e.g., a "windfall tax" of the kind that was applied to UK utilities in the 1990s), through harsher regulatory treatment in the future, or by other means.
- In any case, the financial performance of the company may be only one of a number of criteria that guide the decisions of senior management, along with others described above.

5.14 This paper does not claim to assess in detail the relevance of these considerations for the specific case of the TNSPs active in Australia. However we note that they are likely to be relevant to some degree. We would expect the effect of financial incentives on regulated transmission companies to be somewhat dampened. Whether or not this is desirable is a subject of the following discussion.

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[24] In that regard of course politicians to some extent simply reflect public concerns.

[25] For electricity distribution companies one would often add employment to this list.

[26] The concept of "soft budget constraint" was first developed in the context of socialist economies, but has since been extended to cover a wide range of situations where companies are insensitive to financial incentives. See Kornai, Janos, Eric Maskin, and Gerard Roland. "Understanding the soft budget constraint." *Journal of economic literature* 41.4 (2003): 1095-1136.

How strong should the incentives be?

5.15 We begin by providing a conceptual framework, and then discuss its application to transmission investment.

Conceptual framework

5.16 At the very highest level, one can conceptualise the issues around the design of a transmission investment decision-making framework by reference to the concept of multi-task principal-agent analysis.

Principal-agent theory

5.17 Principal-agent theory in general is the economic theory that describes the design of incentive relations when one entity (the Principal) wishes to have another entity (the Agent) carry out work on its behalf, and has to design a contract that provides the Agent with appropriate incentives.[27] For example, consider a worker (the Agent) serving at the counter in a fast-food outlet, where the owner (the Principal) would like them to serve as many customers per hour as possible.

5.18 At high level, this involves a trade-off:

- At one extreme, one could set a contract with very “low-powered incentives”. In the example, this could involve paying a flat wage per hour, irrespective of how many customers the worker serves.
- At the other extreme, one could set a contract with very “high-powered incentives”. In the example, this could involve compensation in the form of a flat fee per customer served.

5.19 The second approach would clearly give the worker a stronger incentive to work hard and serve many customers, compared to the first approach. However, it might also be quite unappealing to prospective employees, because of the risk that they might find themselves working when few customers turn up, and so earn a low payment. To make up for this, the employer might have to set a high fee-per-customer, so that its total wage bill would be higher.

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27 To be rigorous, principal-agent analysis applies in situations where the Agent has to apply effort (i.e., something that provides disutility); the Agent is better informed than the Principal as to how much effort it has applied; the level of output depends on the level of effort but also on some other factor(s) that are to some extent affected by chance; the Agent is risk-averse.

5.20 As the example illustrates, in general the design of an optimal Principal-Agent contract involves a trade-off between the benefit of eliciting effort through high-power incentives, and the cost of having to compensate risk-averse workers for the risk they bear when they take on high-powered contracts (in situations where the final outcome depends not only on their effort but also on other hard-to-predict variables).

5.21 With regards to transmission investment however, the more relevant insight comes from looking at one extension of principal-agent theory, the area of “multi-task principal-agent analysis”.

Multi-task principal-agent theory

5.22 Multi-task principal-agent problems are a special case, where the Principal requires the Agent to perform multiple tasks. In the fast-food example, the employer might require the worker to serve customers quickly, but also to provide a high level of service (smile nicely, be polite and charming, etc).

5.23 A key point in relation to multiple task situations is that typically *one can measure performance better in one activity than in another*. For example, it is very easy to measure how many customers the worker serves, but very difficult to measure the quality of service he/she provides.

5.24 In those circumstances, a fundamental insight from the literature on multi-task principal-agent problems is that “the desirability of providing incentives for any one activity decreases with the difficulty of measuring performance in any other activities that make competing demands on the agent’s time and attention”.[28] In the example above, the fast-food outlet can give the worker a strong incentive to serve as many customers as possible, but it cannot give him/her a strong incentive to provide a high level of service, because of the measurement problem. Providing a strong incentive to serve as many customers as possible is therefore less desirable if the outlet also cares about quality of service.

Application to transmission investment

5.25 One can think of transmission investment in this framework. The Principal is the regulator/policy-maker (acting on behalf of consumers). The Agent is the transmission owner (or perhaps its senior management). There are two points to note.

5.26 First, the Principal wishes the transmission owner to perform multiple tasks:

28 Holmstrom & Milgrom (1992), p.26.

- Invest efficiently, i.e, build transmission infrastructure that maximises consumer welfare, taking into account reliability and economic benefits;
- Maintain the transmission infrastructure, meet reliability standards, and maximise the availability of capacity;
- Minimise its total costs.

5.27 Moreover, it is clear that performance is more easily measured on some of these dimensions than on others.

5.28 Second, different "incentive frameworks" correspond to lower or higher-powered incentives:

- A non-profit transmission owner or transmission investment decision-maker faces flat (low-powered) incentives. In theory the incentives might sound as though they are completely flat, in practice it is likely that the firm or its senior management will be more profitable and/or happier if they do a better job, but the strength of incentives is likely to be considerably weaker than under other arrangements;
- A for-profit transmission owner faces medium-powered incentives in a regulatory regime that tends towards a "cost-plus" approach. A pure cost-plus approach might in principle be completely flat, but again in practice there will be some level of incentive, and typically it will be stronger than for a non-profit;
- A for-profit transmission owner faces high-powered incentives in a regulatory regime that is based more on "RPI-X" or "incentive regulation" approaches, where its profitability is significantly enhanced when it manages to cut costs. Its incentives are also higher-powered if it faces significant rewards for meeting reliability standards and/or penalties for failing to meet them; and if it faces significant penalties for investing in new infrastructure for which the economic case, as measured by demand for capacity rights, is weak.

5.29 Some of the transmission owner's outputs are easier to measure than others. For example, it is very easy to measure how much the transmission owner spends. If the regulator only cares about cost minimisation, then it could simply give a contract where the transmission owner is rewarded for spending as little as possible. In practical terms, one could imagine setting minimum standards for availability, and an RPI-X type price control that gave very strong incentives for cost minimisation.

5.30 It is arguably more difficult to assess the transmission owner's performance with regards to security of supply. A key point therefore is that *a regulator who wishes to provide strong financial incentives that focus the transmission owner very strongly on cost minimisation and profit maximisation must make sure that it has also put in place appropriate indicators and incentives to guard against under-performance on security of supply*.

5.31 The Productivity Commission appears to have taken this issue on board, and to have felt some concern that strong financial incentives might endanger security of supply:[29]

> *"Unlike distribution networks, transmission networks rarely experience major problems. Problems in transmission can lie latent until major loads and coincident failures in generation or network equipment overstretch the system. The resulting extreme power outages can then affect large populations and entail high costs. For example, in an international context, a major blackout in North America in 2003 led to power loss for up to two days for 50 million people, costing around $6 billion at that time and contributing to 11 deaths. The prospects of relying exclusively on an incentive scheme similar to the STPIS are weak because of the rarity of such events, the lack of good leading reliability indicators (and the potential financial inability of a network business to compensate consumers for the large damages experienced)."*

5.32 The Commission has rightly identified a key issue: whether or not it is possible to identify good measures of performance in ensuring the sustainability to transmission network performance, what it refers to above as "good leading reliability indicators". This has been the subject of considerable debate in the UK. We proceed to describe and draw some conclusions from that debate, as well as from other relevant sources of evidence.

[29] Productivity Commission, pp.16-17.

Output measures/leading indicators of reliability

5.33 The regime of regulation of electricity network companies in Great Britain has been in place since 1990 – at the time of the privatisation of the electricity industry. These privately owned network businesses have been subject to incentive regulation of various forms over the entirety of the period. However, the main regulatory tool was a form of RPI-X regulation that, as we have already noted, incentivised cost minimization. Unambiguously, it has been very successful at this: by 2008, the allowed revenues of electricity distribution businesses had fallen by 60% and those of transmission businesses by 30%[30].

5.34 However, by the end of the 2000s there was a growing sense that this drive for cost efficiency could no longer be sustained and that quality might increasingly start to come under pressure. Combined with other factors such as the large expected increase in capital expenditure to meet demand for the connection of renewables generation, Ofgem decided to review the RPI-X regime.

5.35 This has led to the introduction by Ofgem of a new approach to regulation of energy networks known as RIIO (which stands for Revenue equals, Incentives, Innovation and Outputs). A key plank of the new approach has been to introduce so called "output measures" which are used to set, in part, the amount of revenue that a network company can recover from customers. In the context of the most recent electricity transmission price control, the key output metrics to which financial incentives are directly attached relate to:

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30 See "Regulating energy networks for the future: RPI-X@20 Principles, Process and Issues" Ofgem February 2009 p19 – 21 for a summary of the performance of RPI – X regime since privatisation.

- Reliability – in which the primary output that is measured is based on energy not served. A target level of 316/MWh per annum has been set for National Grid (the transmission company for England & Wales) with an incentive rate of £16,000 per MWh. This implies a maximum upside of c£5m if there is zero energy not served in any one year. The downside is risk is limited to 3% of the allowed revenue of the company – implying a maximum loss of the company of £45-60m.[31]
- Customer satisfaction survey – in which stakeholder views are canvassed and influence the amount of revenue that the company is allowed to recover from customers. Up to 1% of allowed revenue is at stake – implying a total benefit or cost to the company of £15-20m.
- Environmental – some of NG's revenue is also related to environmental factors such as emissions (specifically the leakage rate of Sulphur Hexafluoride used in switchgear) and also a discretionary scheme to "improve environmental performance".

5.36 In addition, Ofgem has developed a basket of Network Output Measures (NOMs) that NG must report on annually. These relate to technical aspects of the TO assets such as criticality, average circuit unreliability, replacement priorities, system unavailability etc. For the forthcoming price control period target levels for these NOMs have been set. The extent to which NG opts to over or under deliver on these output measures influence the overall amount of allowed revenue that NG is allowed to recover – in both up and downwards directions.

5.37 In summary, the concerns noted above regarding the way in which regulated companies that are incentivised on cost minimisation have led Ofgem to develop more sophisticated regulatory techniques for monitoring the reliability of transmission networks. However, with a commencement date of April 2013 the regime is yet to be used in anger: it will be sometime before we learn whether it is effective in achieving the objectives it has set out to do.

Conclusions

5.38 First, it seems possible to develop some measures of investment in security of supply and reliability more generally, although it will be some time before we know whether these measures produce the desired results.

[31] The operation of the RIIO means that it is not known with certainty the level of the allowed revenue. The "Best View" as presented in the Final proposals in December 2012 was that the allowed revenue of National Grid would be between £1.3bn and £1.8bn over the 8 year price control period.

5.39 Second, there are strong countervailing incentives. The culture of a transmission business is one defined by electrical engineers with a very strong focus on reliability. As noted by the Productivity Commission, absent financial incentives the outcome appears to be too much rather than too little reliability.

5.40 The combination of these two safeguards is likely sufficient to meet concerns such as those raised by the Productivity Commission. One would not want to rely on the "engineering culture" alone: that could be changed or over-rode by strong, commercially-minded senior management. However, that would be very difficult in the face of careful, well-designed and implemented regulation to ensure continued attention to security of supply (including regulation to ensure transparency in TNSP operation).