Advice to the AEMC on Rule Changes

Stephen Littlechild

11 February 2012

1. Terms of Reference

The AEMC asked me to provide this paper in the following terms.

> "There are four broad areas that make up the overall work we are doing, which are described in the AER's proposal:
>
> • Capex/opex forecasts - the discretion/powers the regulator has in coming to a determination of the allowed ex ante capex/opex, with a specific focus on the weight to be placed on the proposals of the regulated firms;
> • Capex incentives - what incentives can be placed on the regulated firm to spend no more than an efficient level of capex or opex, and to what extent a revenue determination should be permitted to be reopened mid-period;
> • Cost of capital;
> • Regulatory decision making process.
>
> We are seeking advice from you in the form of a paper. This will form an input into the work on our Directions Paper, which is intended to set out first, whether there is a problem with the regulatory regime which needs to be addressed, and second, our initial thinking on what possible solutions there are to any perceived problems. Your paper would ideally start by considering the problems raised by the AER in the areas of capex/opex forecasts and capex incentives. You should also consider the more specific problems raised by the AER in these areas, including actual/forecast depreciation, and how to deal with assets used for non-regulated purposes. Your paper would then go on to set out approaches that have been employed internationally to addressing these components of a regulatory regime. This would lead on to a consideration of an appropriate framework for assessing solutions to these problems, drawing on the international experience. At this stage we are not asking you to propose solutions themselves.
>
> You should bear in mind as you do this work that the AEMC is restricted to solutions that promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity (the National Electricity Objective)."

The AEMC posed a few additional questions during the course of discussions. I was not asked for advice on cost of capital matters.

2. Problems raised by the AER

The AER identifies a general problem – electricity network prices higher than necessary. It attributes this to limitations on its ability to regulate the network companies effectively – contrasting its own situation with those of other (overseas) regulators. It calls for greater discretion in a number of areas. Specifically (as regards the present advice) these relate to its ability to determine efficient forecasts of capital and operating costs, and to strengthening the incentives on the companies to spend no more than is necessary.

The AER's detailed rule proposals provide, inter alia, for

- reducing constraints on its ability to set estimates of required expenditure, so that the AER would be less constrained to the proposals of the NSP and less constrained by specified expenditure criteria
- limiting the roll forward of RAB to capital expenditure as provided for in the earlier forecast plus 60 per cent of any additional expenditure beyond that
- giving the AER discretion to determine whether NSPs should use actual or forecast depreciation
- giving AER greater flexibility to introduce other incentive schemes
- enabling AER to provide for customers to benefit from shared assets that are also used for other purposes.

3. Views of others

I note the following general stances:

- Customers and some government views generally agree with most of the AER's analysis and proposals.
- NSPs, in contrast, argue that that AER has not identified a valid set of problems. In their view, the present rules are actually working well: there is greater regulatory certainty and investment is taking place. This was to be expected and is to be welcomed. Although electricity prices have increased, this is attributable partly to legitimate increases in investment and partly to international fuel price increases and to increases in other costs (e.g. environmental). In most (but not all) respects, greater regulatory flexibility is neither necessary nor desirable.

4. My initial general reactions

The AEMC's consultation poses four main questions:

- Whether participants agree with the nature of the problem
- Whether the proposal achieves the right balance between prescription and discretion
- Whether the AER could already achieve the outcome sought through the use of existing discretion, and
- Whether the solution proposed is the preferred solution, or whether a more preferable solution exists.

On the first question, the NSPs make some valid arguments about the success of the regime (in terms of regulatory certainty and achieved investment). However, it seems to me that they do not fully address the AER's concerns as to the possibility (or likelihood) that investment has been and still is excessive and at an unduly high cost to customers. There is scope for further analysis of the available empirical evidence, but there is likely to be a case for considering rule changes.

On the second question, one of the responses (Victorian Minister for Energy and Resources) makes the point that the National Electricity Market Rules represent a swing from an earlier outcomes-based approach to a prescriptive approach, and suggests that "a swing back towards a more outcomes-based regime will achieve a better balance between the interests of consumers and the businesses as sought by the AEMC in 2006". On the evidence available so far I am inclined to share that view. An unduly prescriptive regime can be expected to prove inflexible, and a move towards greater regulatory discretion correspondingly appropriate. (Though it might be argued that the UK regulator has exercised rather a lot of discretion, as explained below.)

On the third question, the NSPs make a rather powerful case that, in practice, AER has not been constrained in the ways that it alleges, hence the case for relaxing the Rules is not made out. This needs to be explored further. It is possible that the general difficulty of challenging an incumbent company and the burden of establishing a reasonable case, rather than the specific wording of the Rules, may be the operative constraint on the AER. Nevertheless, my sense at this stage is that the present wording of the Rules may constrain AER more than other regulators are constrained; that if the wording does not in fact constrain the AER then there is no obvious loss in relaxing it; that some relaxation of the Rules would be conducive to better achieving the National Electricity Objective; and that it would be an advantage to be able to hold the AER clearly responsible for its regulation, rather than face the argument that any deficiencies were attributable to imperfections in the Rules. But I accept that relaxing the Rules will not solve all problems, particularly those associated with government-owned NSPs not responding to financial incentives in the same way as privately-owned NSPs do. This raises the question, touched upon in a different part of this set of proceedings, whether different arrangements are appropriate for public as opposed to privately owned NSPs.

On the fourth question, my present feeling is that, on most questions, the AER's proposals are broadly appropriate. My main reservations are on the proposal to allow 40% of capital expenditure beyond the forecast level, and the proposal to delete the 'relevant circumstances' criterion. As to whether a more preferable solution exists, there is one important factor that is increasingly playing a role in other regulatory jurisdictions, but is not mentioned in the present proposals and discussion. It was not particularly current at the time of writing the NEM Rules but may be relevant now. That factor is the potential role of customers and users in the regulatory process for determining network price controls. Some possibility for that potential role seems worth exploring here, rather than focusing entirely on variants of the AER's proposed rule changes.

5. Approaches employed internationally

I briefly describe the approaches employed in two countries: the US and the UK. Then I discuss some respects in which their regulatory approaches have evolved over the last decade or two.

a) US regulatory approach

In contrast to Australia and the UK, the US has traditionally applied a largely backward-looking or ex post regime (though this is changing, see below. For a helpful review, see Scott Hempling and Scott H Strauss, "Pre-Approval Commitments: Under What Conditions Should Regulators Commit Ratepayer Dollars to Utility-Proposed Capital Projects?", National Regulatory Research Institute, 08-12, November 2008.) Until around the 1970s, utilities had to demonstrate to the regulator that costs were prudently incurred and that the resulting plant was "used and useful" before it was included in the regulatory asset base. The assessments have been summarised as follows:

> In connection with the proposed rate increase, the regulator engages in several assessments, the aim of which is to determine whether the costs proposed for inclusion in rates were prudently incurred and whether the resulting utility plant is used and useful for serving the public. Those assessments include: (1) examining the utility forecasts that supported the decision to build the project, thereby satisfying itself that the project was, in fact, needed; (2) assessing the project choice, including reviewing whether potentially less expensive alternatives were considered and, if so, why they were not pursued; (3) evaluating whether the methods and sources of plant financing reflect prudent decision-making; and (4) conducting a review of the reasonableness of construction costs and the timeliness of completion. Upon completing this review, the regulator disallows costs that it finds were caused by the utility's imprudence. (Hempling and Strauss p 4)

There was typically no requirement to gain regulatory approval in advance for a capital expenditure plan. Similarly, prices (rates) would be set on the basis of a test year which was typically the last historical year for which data is available. Sometimes the test year was the current year or even the forthcoming year, but there was relatively little need to forecast more than one year forward.

On this basis, US regulation was typically not exercised by the problems of forecasting either opex or capex for, say, five or more years ahead, at least for networks as opposed to generation plant. Consequently, nor was there a problem of dealing with divergences between actual and planned capex.

At the time of designing the UK and Australian regulatory approaches, it was widely held that the US approach was not conducive to improvements in efficiency because it was in the nature of a 'cost-plus' arrangement. Rates would be set to reflect whatever costs happened to be, with little or no incentive on the utility company to reduce or constrain costs, and every incentive to increase capital expenditure. This was reflected in the 1962 article by Averch and Johnson.

In 1974 Joskow pointed out that, with inflation and rising rather than falling costs, US utilities found it increasingly difficult to live with rates set many years previously. But they also found it difficult to make the case for rate increases, since they now had to bear the burden of proof. Consequently, they had an incentive to keep down their operating and capital costs to avoid the need for such an application. Moreover, in the early 1980s the regulatory commissions disallowed substantial nuclear cost overruns.

To reduce the need for lengthy, costly and uncertain hearings as costs increased, and to reduce the risks on utilities of incurring costs for which they might not get paid in full, there was a move to pass-through certain costs as incurred. Examples include fuel cost pass-through, riders, trackers and surcharges with relation to (e.g.) energy efficiency, renewable energy purchases, smart grid costs etc. There are also some preapprovals, where the commission undertakes not to question the reasonableness of particular utility actions or costs.

Procedures have evolved over time, and vary from one regulatory body to another. At FERC, for example, capital expenditure is usually approved in advance. FERC has a process where smaller amounts are deemed proved in advance for projects such as replacing compressors, replacing old pipe, etc, as long as it is below a certain dollar amount. However, any large project needs certificate authority from FERC. No pipeline would build an extension or new pipe without customers that have already signed contracts, and without FERC approval, because the costs would be at risk in a rate case. The certificate process sets initial rates, but the rates are reviewed in the next rate case filed.

The situation is quite fluid at the moment. For example, within the last year AEP Texas initiated a series of discussions with Texas PUC about ways to streamline the traditional rate setting process, especially to address the regulatory lag between incurring costs and recovering them. One mechanism under discussion is the ability of a company to update its capex annually and adjust its rates according to the previously approved ROE, with reconciliation at the next full cost of service review. A similar proposal is under discussion in Illinois. At FERC there is a formula rate process on the electric side, where the inputs can change yearly by a filing by the company, but not on the gas pipeline side.

In the US generally, a number of questions are being asked about such pre-approval processes. These include

- does the combination of a pre-approval process plus some form of ex post verification with the possibility of adjustment provide as much protection for customers as the previous regime that required investments to be proved 'used and useful' before entering the rate base?
- does it require a more active role for the regulator?
- what is the relationship between the conditions of a pre-approval that might be granted by a state legislature or regulatory commission and the detailed obligations and processes that a regulatory commission would normally go through? For example, if a state legislature approves a Smart Grid programme, does the utility still have to prove that such investment is used and useful or not? Or again, state commissions have variously required an integrated resource plan and FERC's recent Order 1000 orders utilities to engage in regional planning process for transmission. But what if anything is the link between a plan and cost recovery on a particular project?
- to the extent that devices such as riders or preapproval reduce regulatory risks, to what extent should this be reflected in a lower allowed return on equity? The answer presumably depends upon a wide variety of circumstances. The issue has been argued in a number of US cases, with an outcome of 0.50% reduction in several of them.

The possibility of transforming the Australian approach to the US approach is presumably beyond the terms of reference of the present consultation, even if anyone were advocating it. Nonetheless, some particular aspects of the US approach may be of relevance in the present context. For example, consider the retrospective (ex post) assessment of whether new investment should be included in the rate base. The AER opposes this on two grounds: that it "may add to regulatory risk by creating potential for investment write downs. In addition, the evidentiary burden that the regulator must satisfy before it could disallow an investment is so high that ex post reviews may offer limited protection against inefficient expenditure.” (pp 43-4) Presumably the evidentiary burden could be lightened by appropriate change in the Rules. As to regulatory risk, US experience and present debate suggests that this is an issue, but that the relevant question is when and how new investment should be assessed by the regulator – before, during or after construction – rather than it be arbitrarily assumed that a specified percentage is acceptable and the remainder is not. Whether “a sharing mechanism generates more effective incentives to invest efficiently” (p 44) is equally true for publicly and privately owned firms is debateable, and not tested by US experience.

Another major development in many US jurisdictions (and parts of Canada) is that customers and users are becoming quite actively involved in setting rates. The most striking development is the use of negotiated settlements, whereby a proposed rate increase (typically) is discussed with users and their representatives and in many cases a modified agreement is reached, which is then typically endorsed by the regulatory commission. At the Federal Energy Regulatory Commission (FERC) this typically happens with about 90% of rate proposals. At FERC the regulatory staff play an active role in facilitating this negotiation and settlement; other regulatory bodies might be less involved, but still typically encourage negotiated settlement in principle.

b) UK approach

The Australian approach is largely based on the UK approach, which involves the regulator setting prices based on an assessment of efficient operating and capital costs for the next period of, say, five years. In numerous respects UK regulators have had similar thoughts and experiences as in Australia. From the beginning, UK regulators have been concerned to avoid undue price increases, have been very conscious of incentives for regulated companies, have deliberated at great length over how to determine efficient operating and capital cost projections, and have worried about how to deal with both under-expenditure and over-expenditure compared to the assumptions made in setting the price controls.

The main difference between Australian and UK energy regulation is that the Australian approach is now constrained to operate within the National Electricity Market Rules, which are very prescriptive and allow minimal discretion to the regulator. In contrast the UK approach is very discretionary, imposing few if any limits on what the regulator may propose and how it goes about calculating the details of its proposals.

c) Regulatory discretion

This is not to say, however, that either UK or US regulators are as unconstrained as the AER implies in its Box 3.1 summaries of the use of discretion by economic regulators. (AER Proposal p 15) It says that “In other jurisdictions, lawmakers have found it appropriate to empower regulators to regulate prices based on their expert judgement, with only high level guidance as to how this should be achieved.”

- For Great Britain, the AER summarises the statutory objective and duties, then says “Beyond these high level obligations, the Authority [Ofgem] is empowered to impose such licence conditions as appear to the Authority to be requisite or expedient having regard to its statutory duties.” However, it should be noted that Ofgem does *not* have the power to *impose* licence conditions – it may only *propose* them, and if the regulated company does not accept then Ofgem may propose them to the Competition Commission, which will hear the views of Ofgem and the company and other interested parties, and make its own recommendation which Ofgem then has the power to impose.

- For the US, the AER notes the statutory obligations on FERC then says "Beyond these high level obligations, FERC has scope to set allowances as it sees fit, subject to judicial-style regulatory proceedings". These judicial-style proceedings are actually a significant constraint on FERC, insofar as both the utility and FERC staff and any other interested party has to put proposals and evidence to an Administrative Law Judge (ALJ). All these arguments are challenged and tested in court. The ALJ then has to make a decision based on the evidence presented, and the ALJ's decision stands unless the Commission sees good reason to change it.

In summary, it is true that both UK and US regulators do have much greater discretion in what they propose. However, their ability to "impose" that solution is in practice more constrained than the AER indicates.

It is worth noting parenthetically that the ability of UK companies to reject the regulator's proposals, forcing the regulator to take the whole of any disputed price control to appeal, has been absolutely critical in bringing about a broadly sensible regulatory relationship and outcome. It is not simply a protection for companies in the event that regulatory proposal is unreasonable: it also means that the regulator needs to consider much more carefully beforehand whether the proposal being put forward is likely to commend itself to an independent body. The companies, for their part, cannot cherry pick the elements of the proposal that they like. If they reject a proposal, they run the risk that an element that they like will be modified. In the event, relatively few disputed licence changes have gone to the Competition Commission.

I commented above that the UK regulator had exercised rather a lot of discretion. I am thinking here of the increasing variety of incentive schemes that are included in network price controls nowadays. The sliding scale introduced in 2004 and used again in 2009, and the RIIO approach to replace RPI-X for 2015 onwards (see below) are major examples. Such approaches provide flexibility and innovation. They can also be attractive to the regulated companies, so opposition of the companies does not present a particular obstacle to their adoption. However, they do rely on the regulator being able to calibrate the incentive scheme appropriately. This includes being able to judge what response the scheme will bring from the regulated companies at different incentive levels and how much of each particular output customers are prepared to pay for. This is a lot to ask of a regulatory body. But rather than prohibit discretionary schemes, I would argue for involving users and customer representatives in the design, adoption and monitoring of them. This gives a better chance that the discretionary schemes will turn out to represent value for money.

I am concerned, as are other economists, at some of the radical measures that Ofgem has taken and proposed with respect to regulation of the UK retail energy sector. In my view these measures would seriously undermine a competitive market. But here too, rather than impose further formal limits on what Ofgem can do, I would hope that discussion and proceedings within the present regulatory framework would address this issue.

I am asked whether including outputs in the Rules would be a good or bad thing. Pending further discussion and understanding of the way in which the Rules actually work, my general feeling is that anything that gives the regulator the necessary flexibility to address a particular problem in the most effective way is to be welcomed. But anything that requires the regulator to act in a particular way, or to do or not to do something, runs the risk of unintended outcomes. It would not seem a bad idea to enable regulators, companies and their users and customers to discuss the possibility of designing rules to circumscribe the kind of capex that would or would not be allowed during a price control period. At the end of that period it would be possible to ascertain whether that rule had been broadly useful and should be continued, or was subject to limitations that could be addressed, or had proved so unacceptable that it should not be used in future. It seems sensible to learn from experience, and to do so as easily as possible, rather than to erect undue barriers to experimentation.

d) The forecasting and incentive problems

The UK energy regulator Ofgem has in practice been quite innovative in addressing the forecasting and incentive challenges to which the AER refers – as indeed have other utility regulators. They have tried new ideas and revised them in the light of experience. In contrast, the Australian Rules have the look of an approach that is set in stone, reflecting the approach that was current at the particular time that the Rules were set, but now looking cumbersome and dated.

We might identify three broad avenues or stages that Ofgem and other UK regulators have explored for dealing with the forecasting and incentive problems. The first is to try to inform themselves better so as to strengthen their ability to challenge the incumbent regulated network company. The second is to accept that, in certain respects, they will not be able to do this, and to look for ways of incentivising the companies to "do the right thing" nevertheless. The third is to look to customers and other users of the network to specify what they want, and to discuss or negotiate with the company to achieve an outcome that they can support. I explain and discuss these below.

(i) Focus on informing the regulator

The first approach or stage has been for regulators to better inform themselves by involving considerable advice and resources in the process of estimating future capital and operating expenditures and then setting the price controls. This includes the extensive use of engineering and management consultants to challenge the projections put forward by the companies. It involves detailed prescription and supervision of costing and cost allocation. Comparative and econometric analyses of costs are used to assess where the performance of other companies suggests scope for further cost reduction in future. Increasingly, such evidence is presented for comment and discussion. Over the course of the price control review, in the light of accumulating evidence, Ofgem gradually formulates and refines its assumptions and proposals.

Initial and revised proposals by the companies play a significant part in the process, but the regulator is in no way constrained to adopt these proposals or to relate its own proposals to them. This is not to say that the regulator is quite unconstrained: recall that it can only propose rather than impose. The UK regulator therefore constantly has to ask itself: are our assumptions and proposals sufficiently close to the regulated companies' own assumptions and proposals that the companies are likely to accept? If not, are our assumptions, proposals and arguments likely to be more plausible to the Competition Commission than the assumptions, proposals and arguments of the companies?

As regards incentives, it is taken for granted that the companies will tend to build some 'fat' into their projections of opex and capex. The aim of the regulatory price control process just described is to challenge those assumptions and allow only a reasonably efficient level of cost. Once the price controls are set, it is assumed that the companies will seek to minimise their operating and capital costs. It is normally to be expected that their actual operating and capital costs will be below the levels projected in setting the price controls.

It seems to be generally accepted that a company can legitimately beat its operating cost forecast, but beating its capex forecast is more problematic for a regulator. If a company decides that it does not need to make investments that it or the regulator previous assumed were appropriate, why has it changed its mind? Does this indicate a degree of deception by the company or naivety by the regulator? Why should customers pay for projected investment that does not in fact take place? Ofgem's initial response in 1999 was to investigate why such 'underinvestment' had been possible, initially concluding that it generally reflected opportunities for improved investment selection and control that had not been fully available or recognised at the time of setting the control, and that were also reflected in increased operating costs. As I recall, Offer or Ofgem had already decided that the RAB would increase only by the actual new investment (assumed to be found allowable) rather than by the previously forecast investment.

On the whole, this approach worked fairly successfully, in all the utilities. In the early days it may have appeared that the regulators were not tough enough, perhaps because they were not well enough informed, or perhaps because the scope for efficiency improvements was greater than regulators and companies themselves initially expected. But over time the regulatory price controls have become more challenging, and customers have benefited from considerable capital investment and quality improvements, with (until recently) significant cost and price reductions. (In the water sector, there has been much greater capital investment and quality improvement, with lower price increases than would otherwise have been feasible.) Nevertheless, there have been limitations and criticisms (for example, as to increasing complexity of process and whether regulators know better than companies). Regulators (and critics) have therefore sought improvements and explored alternative approaches.

(ii) Focus on incentivising companies

The second stage response has been for the regulator implicitly to accept that the regulated company will know more than the regulator will, and to try to provide more sophisticated incentives for the company to act in the interests of customers (and the regulator). An example here would be the use of incentives and penalties in the price control that seek to reward companies for providing information and making predictions that are "correct" and penalising them for information and predictions that are "incorrect". An additional advantage of this approach is that, if successful, it avoids or minimises the need for the regulator to investigate and assess ex post whether the investment programme has been appropriate.

A particularly important form of this is Ofgem's use of sliding scale regulation in 2004 that was developed into its Information Quality Incentive (IQI) Scheme in 2009. An approach of this kind is sometimes called 'menu regulation'. The regulator proposes a menu of options for each company, with different combinations of projected output and capital expenditure and return on investment. The company may choose whichever combination it prefers. The aim is to give the company an incentive to reveal its true thinking, and to reward those companies that correctly predict what customers will do and invest accordingly. Thus, a company that over-eggs its capital expenditure forecast will be penalised unless it actually invests in accordance with that forecast.

In 2004 Ofgem was faced with two companies (owning 5 out of 14 distribution networks) that argued for capital expenditure significantly in excess of the capex deemed appropriate by Ofgem's engineering consultants (whereas the proposals of the other 9 network companies were in line with the thinking of Ofgem's consultants). Ofgem was concerned that one of the companies would not subsequently deliver that projected investment, thereby being paid for not investing, whereas the other company might actually deliver the projected investment, but that this would be excessive relative to what was needed and what customers would be willing to pay for. In the event, the sliding scale incentive scheme induced both companies to modify their planned investment ex ante, which enabled Ofgem to accept their plans, thereby averting a 'showdown' at the Competition Commission.

In 2009 Ofgem noted that the sliding scale mechanism had the advantage of encouraging companies to modify any excessive investment plans, and used it again in developing the price controls for 2010-15. This general approach has been extended in Ofgem's thinking for the forthcoming set of price control reviews. For example, a central aspect of Ofgem's new RIIO approach (Revenues = Incentives + Innovation + Outputs) is to specify targets for companies and to reward those companies that achieve these targets and penalise those that don't. We have yet to see what the specified targets are. An Appendix to Ofgem's opening letter on the distribution price control beginning 2015 (published on 6 February 2012) gives details of the Outputs envisaged, but is couched in rather general terms. An output may ultimately be specified in such abstract terms (such as 'meet demand without a shortage or surplus of capacity') that it will not require specific knowledge by Ofgem, and will put the onus on the company to forecast correctly. Quite how the allowed revenue will be set (if not on a building block approach requiring some approved level of capex) remains to be seen.

Ofgem has adopted other incentive schemes of various different kinds, which seek to achieve particular goals, including innovation. My impression is that companies have generally welcomed the greater use of incentive schemes and of menu regulation, not least since it gives them greater opportunity to earn additional income at a time when the scope for out-performance on the basic price control may be declining.

A downside of this approach is the greater complexity of the price control discussion papers and resulting controls. It requires considerable information and judgement on the part of the regulator to design the incentive schemes. The responses of the companies may not be entirely predictable, nor the resulting levels of profit (or loss). This in turn may necessitate continual revision of the schemes.

Thus, for example, AER (Box 6.3) describes how Ofgem took measures to prevent stop-start investment by means of a five year capex rolling incentive mechanism, introduced in 2004. This caused other problems, and had to be modified to a two year scheme. Elsewhere, it has been pointed out that Ofgem's Information Quality Incentive (IQI) scheme provides a significant incentive to spend less than the capex allowed for in the price control (an incentive/penalty rate of 29% to 40%, average 34%, for underspend/overspend in 2005-10, and averaging 47% for 2010-2015). (Tim Tutton, "Will distribution network operators invest what is needed"? *Oxera Agenda*, February 2010: 1-5)

Another concern is a lack of specificity about what the investment programme is meant to be delivering, and a consequent ambiguity about whether the companies have achieved a profit by efficient economising or by cutting corners on the health and capacity of their assets. Accordingly, in 2009 Ofgem indicated that the RIIO approach (for 2015-2020) would put more emphasis on the specification and meeting of required outputs. As noted, these outputs have yet to be specified in any detail.

Hence regulators still need to discover relevant information, and to concern themselves about incentives. This may be increasingly difficult in a more innovative and rapidly changing world, where simple projections of demand and capacity are no longer sufficient or even possible.

(iii) Focus on the role of customers

The third approach or stage is presently in course of evolution (and is partially reflected in Ofgem's RIIO thinking). UK regulators have always been uneasy at dictating capex plans to companies, not least because companies can then blame regulators if anything goes wrong. Regulators are therefore keen that companies should "take ownership" of their capex plans. Regulators are increasingly taking the view that customers or users of the regulated company have an important role to play in the process of setting price controls. This is partly because customers have a better idea of their own preferences than the regulator. But also, by discussing and/or negotiating with each other, companies and customers may be able to arrive at a mutually preferable alternative to what the regulator might impose, but nonetheless not inconsistent with what the regulator might regard as acceptable. This will enable companies to "take ownership" of the resulting plan. And of course it will generally suit the regulator better to have customers supporting the outcome rather than criticising it, especially if some difficult price increases might be involved.

In the UK, this approach has been most marked in the case of the airport regulator. At the last price control review, the Civil Aviation Authority (CAA) invited the airports and airlines to see if they could agree on certain key inputs into the price control, namely, traffic forecasts, additions to capital expenditure, and quality of service standards. The CAA undertook to build agreed inputs into the price control setting process. Despite expectations to the contrary, the airports and airlines did reach agreement on these parameters at the two major London airports. The process was successfully repeated in setting air traffic price controls. The CAA and the industry are presently considering an extension of the process to allow the London airports and airlines to negotiate and agree the next price controls. They are also discussing innovative incentive schemes (e.g. reward-shares for cost reductions stemming from joint work by airports and airlines).

Ofwat and Ofgem have been more cautious, but have taken the view that both they and the companies should engage more actively with customers and users. Ofwat and Ofgem will make their own decisions in setting the price controls. However, customers will be involved in the process of setting the RIIO targets that the companies will be incentivised to meet. And companies that can show that their customers approve their plans will be challenged less thoroughly than companies that have not engaged or that are in dispute with their customers. Ofgem has recently decided that two of the four transmission companies should remain on a Fast Track in setting the new price control while the other two should be put onto a Slow Track (albeit for reasons not only related to their engagement with customers).

An advantage of this approach is that it makes greater use of the potential knowledge of customers. This may be more relevant where the customers are fewer and better informed, as in airports compared to water and electricity. But it could also empower customer groups in sectors like water and electricity. It encourages companies to discover and provide the quality of service that customers want, involves customers in the process of discussing and agreeing a price control and the investment programme that underlies it, and enables customer groups to play a more significant role in monitoring and revising the implementation of the price control.

In some sectors, a challenge is to identify and/or encourage customer representatives that will be able and willing to play an active role in such a process. The process is actually underway in Scotland, where the water regulator there has put together a Customer Forum to negotiate with the water company.

This approach to setting a price control is perhaps more akin to the negotiation and monitoring of a commercial contract. It assumes active rather than passive parties, who know what they want. The contract specifies what is to be delivered, with provisions for monitoring and enforcing this, and where necessary for modifying it. The parties then monitor and revise the contract in an ongoing relationship. Throughout, the regulator is facilitating this process, and standing by to act as a default option if necessary. This is in contrast to a ‘once every five years’ negotiation, with the regulator unsure what it wants in specific as opposed to general terms, followed by a hands-off approach for the next five years. It also potentially reduces the problem of ex post assessment because the price control is likely to specify more precisely what is to be delivered and when, rather than leaving this to the discretion of the regulated company.

This third approach of customer engagement is based on earlier and ongoing experience with negotiated settlements in the US and Canada. Another illustration is the so-called public contest method for determining transmission investments in Argentina. Major investments there are not decided upon by the incumbent transmission company or its regulator. Rather, they are proposed, voted upon and paid for by those users that would benefit from them, and then put out to competition to determine the price. Despite initial scepticism and reservations, this approach worked well.

The customer engagement approach is a particular interest of mine. However, it is fair to say that the application of this approach to the UK energy and water sectors is a work in progress, with some scepticism on the part of some parties, and some question as to how it will develop over the course of the next few years.

I note that at least two of the respondents to the consultation make a recommendation consistent with this approach. See SPAusNet p 23 and the following:

> The most beneficial improvements we can see go beyond the rules themselves. They are improvements to increase stakeholders' confidence in rules outcomes. Firstly, Jemena strongly supports better resourcing for consumer groups so they can be more a part of the price review process from start to finish, have a much deeper level of understanding of the issues, and provide meaningful input into the AER's decisions being made on consumers' behalf. (Jemena)

6. An appropriate framework for assessing solutions

i) General context and need for reform

AER asserts that prices are unduly high as a result of restrictions on its discretion; the networks deny this. All parties could usefully be pressed on this.

The NSPs argue that it is too soon to evaluate the Rules. However, the concerns relate to the recent price determinations that have been carried out under the Rules, they obtain for periods of years, and it is not clear what further information could be gained by deferring consideration of them.

There would also seem scope for AEMC to carry out or encourage research on this question of prices. Three specific areas occur to me.

First, Bruce Mountain and I made some comparisons of distribution network prices in NSW, the UK and Victoria. We found, for example, that UK prices were significantly lower than NSW prices, and that Victoria was in-between. Our research suggested to us that ownership and regulation and the regulatory framework were all potentially significant factors. It seemed that government-owned companies had greater interest than private companies in capital expenditure, less incentive to reduce costs and expenditure, and less concern about overrunning price control targets. Regulation of state-owned companies was less effective in setting and enforcing challenging targets and curbing the excesses of the state-owned companies than regulation of private companies. Regulation under the NEM Rules was less effective in doing so than regulation under the previous jurisdictions. Bruce Mountain has extended this work to other jurisdictions and to transmission as well as distribution companies, with similar results.

The parties might be pressed on some of these issues. What about the results that find (e.g.) that allowed rates of return are higher under NEM Rules than elsewhere? Also, several submissions (including FIG and SPAusnet) suggest that concerns relate primarily to networks in NSW and Queensland and that the system is working well in Victoria. Is it realistic to assume that publicly owned network companies will respond in the same way to incentives as privately owned companies will? Is it sensible to set the same incentives, and indeed to have the same regulatory framework? I appreciate, of course, that AEMC does not have the power to determine ownership, but it may be that this is something it could comment on as worthy of consideration by relevant policymakers.

Second, there would seem to be scope for a more sophisticated econometric analysis than Bruce Mountain and I were able to carry out. There are now enough observations of a cross-section and time-series nature. This research would seek to quantify the size and significance of the various potential explanatory factors. It could seek, in particular, to separate out the effect of ownership and the effect of different regulatory frameworks. This could inform a discussion of whether there should be different regulatory provision for privately-owned and government-owned network operators.

Third, it ought to be possible to make some rough calculations of the magnitude of the various factors that might be contributing to high or excessive electricity network prices. Suppose allowed rate of return were reduced by, say, 1% - what effect would this have on prices? Ditto with forecasts of opex and capex, and capex overruns. How much does each potential factor typically contribute to the observed phenomena that are the cause of concern? Where is AEMC's effort most worthwhile, in terms of impact on final electricity prices?

ii) the balance between prescription and discretion

AEMC has raised the question of the correct balance between these two factors. One respondent has in effect suggested that the present NEM Rules are at the prescriptive end of the spectrum, and that this is bound to be problematic. AEMC might pose the general question as to whether respondents perceive the Rules in this way, whether they are aware of other approaches that are at all similar to the NEM Rules, whether such other approaches have encountered similar problems, or whether they have corresponding advantages, etc. In this context the NSPs and others might be asked whether there are challenges in adapting such an approach to an increasingly fast-changing world.

Some parties claim that a prescriptive approach reduces regulatory risk and hence the cost of capital. Is there evidence that the cost of capital is lower in more prescriptive regimes than in more discretionary ones? Bruce Mountain and I calculated that the regulatory allowed cost of capital was higher under the NEM Rules, not lower.

iii) efficient forecasts of capex and opex

AEMC's third question is whether the AER could already achieve the outcome sought through the use of existing discretion. The NSPs (and especially their joint consultancy report) have provided some pretty systematic evidence that the AER has frequently done what it claims to be difficult or impossible to do, with respect to challenging and changing the proposals put forward by the companies. AER has said that, even so, the regulatory forecasts embodied significant cost increases.

AER should be asked to respond to this evidence. In what respects was AER nonetheless constrained? If it considered that tougher assumptions on costs were appropriate than it actually proposed or determined, what prevented it from proposing or determining such tougher assumptions?

The NSPs make other points, eg noting that the AER seemed to voluntarily accept the form of the company proposals, even though it was not required to. Again, there are important questions on which to quiz the AER.

The discussion (and the AER's later proposal) seems to focus almost entirely on aggregate demand and capex, with little reference to the composition of that demand and capex. Does it not matter what is constructed and where?

This might be a point at which to introduce questions about the views of customers. The NSPs assert that they are best placed to forecast demand and determine investment plans. (Or at least better placed than the AER.) What steps have the NSPs taken, or should they take, to ensure that the investments that they are proposing are consistent with what customers would most prefer? Do customers have a preference between different types of investment, or as to timing? Would customers prefer to invest now to ensure that there is adequate capacity, or defer investment to minimise rate increases at the present time? Do NSPs and the AER consider that the views of customers are relevant in this context? If not, why not? But if so, how do the NSPs propose to acquire such information?

iv) increased discretion for the AER

The AER's specific proposals include to remove various obligations that constrain it to relate its decisions to 'the basis of' the NSP's current proposals, and to amend those proposals 'only to the extent necessary' to enable it to be approved. Experience in the UK suggests that such restrictions are neither a necessary nor a desirable part of the regulatory approach. No one has ever suggested that the UK regulator be constrained in this way. Perhaps the AEMC's consultation might ask why such restrictions are deemed necessary in Australia? Or if they were justified initially, does that justification still obtain now and for the future?

v) expenditure criteria

The AER proposes to modify/simplify/abolish the expenditure criteria. Is there reason to believe that doing so, while leaving in place general duties on the AER, would be harmful to companies or customers? Would it make any difference?

One particular criterion seems to be of a different character. The AER's proposal would remove the reference to the 'circumstances of the relevant distribution or transmission network service provider'. Some interpret this to mean the financial circumstances of the owner of the network, rather than the local circumstances in which the business operates, but this needs to be clarified. It also raises borderline issues. If the business is heavily cash negative, is that a relevant circumstance?

One submission (ERAA) suggests that "good benchmarking practice will automatically take into consideration the circumstances of individual networks, and that this amendment should facilitate an increased use of benchmarking." Regulatory experience elsewhere suggests that this is somewhat optimistic: benchmarking has its place but cannot take account of all the circumstances that differentiate one network from another.

I am asked whether there would be any benefit in a rule that requires the regulator to undertake benchmarking. I would say that it would be good regulatory practice for a regulator to consider what if any insights benchmarking could provide in the particular price control under consideration, and to take this into account where appropriate. But as just noted, the circumstances of individual networks can vary greatly, and in my experience there is always an element of unexplained variation where judgement is required. To require the regulator to undertake benchmarking therefore runs the risk of forcing the regulator to attach more weight to benchmarking than the circumstances allow. The difficulties experienced by the Dutch electricity regulator may be an example of this. (Nillesen, P.H.L. and Pollitt, M.G. (2007) "The 2001-2003 electricity distribution price control review in the Netherlands: regulatory process and consumer welfare." *Journal of Regulatory Economics*, 31(3): 261-287)

AER's argument here is less persuasive than elsewhere. AER suggests that it would not be appropriate to consider the particular circumstances of a network. But in the abstract, it is difficult to argue ex ante that any particular circumstances could not or should not be taken into account.

Ofgem has been concerned about the financial position of energy suppliers. Admittedly suppliers are in different circumstances from network providers (not least, because they operate in a competitive market). Ofgem has taken steps to ensure that all networks and suppliers have appropriate financial cover. But in the event of an unexpected crisis, measures related to the particular circumstances of a NSP may be the least undesirable way forward. Thus, a whole range of regulatory actions might need to be considered, together with the powers available to the AER or others. The phrase about circumstances of the relevant provider therefore needs to be considered in a broad context.

Respondents to the consultation will no doubt be invited to comment specifically on this issue. AER might be invited to clarify which circumstances would be appropriate to take into account and which not, and to discuss whether this might unduly limit the regulator's powers in unexpected difficult situations.

vi) capex incentives and rollforward

The AER is concerned that companies might have insufficient incentive to choose the efficient level of investment and to limit their investment to the levels embodied in the price control. As a solution to this problem it proposes that only capex up to the forecast level should be automatically rolled forward into the RAB, and that only 60% of capex beyond that should be so incorporated into the RAB.

This seems to me the least persuasive of the AER's arguments. If there is a potential problem with investment exceeding the level assumed in setting the price control, why assume that any of it is acceptable? Why assume that 60% of this is acceptable and 40% is not? Those percentages seem arbitrary. They seem to lack the systematic consideration that Ofgem has given to its incentive and penalty rates under its IQI scheme (though these have not been uncontroversial, see Tim Tutton article above).

Indeed, should it be assumed reasonable that capital expenditure equal to the level assumed in the price control should be incorporated into the RAB without further investigation? What if the NSP had built half the planned additional capacity and incurred twice the envisaged cost for it? The total expenditure would be as planned but the capacity would not be. Should there be no check on this? The whole discussion makes remarkably little reference to the composition of the planned and actual capex, both forecast and exceeding the forecast.

The AER says that "The approach outlined above assumes that NSP will respond to financial incentives. Some stakeholders have suggested that NSPs respond to a broader range of incentives and other mechanisms may be more effective in promoting capex efficiency." (p 43). Various respondents have questioned whether such a rule would in fact provide the desired incentive to be more efficient. The AER adduces evidence from NSW and Queensland. In these states the network companies are government-owned. In Australia and elsewhere there is evidence that government-owned companies are less responsive to incentives to curb capital expenditure. Is a 60% rule really the best way to deal with what may well be a more fundamental underlying factor?

The AER says that it has looked at other approaches.

> "Under an ex post capex review approach, each NSP's investment program is subject to regulatory scrutiny at the time of the next regulatory review. Only efficient and prudent expenditure is rolled into the RAB. This approach is in widespread use overseas and in the National Electricity Market prior to the 2006 reforms. …
> However, the AER is concerned that by requiring an assessment of the efficiency of investment decisions after they have been made, ex post reviews may add to regulatory risk by creating potential for investment write downs. In addition, the evidentiary burden that the regulator must satisfy before it could disallow an investment is so high that ex post reviews may offer limited protection against inefficient expenditure." (pp 42-3)

These points deserve consideration. However, experience in the US does not seem to rule out ex post capex reviews. Greater customer involvement in the regulatory process could be relevant here. Customer groups would be concerned to ensure that the NSPs delivered what they had promised, and did not saddle customers with additional costs to which they had not agreed.

There is surely a fundamental question why an NSP has exceeded its allowance. There may be a good justification or there may not be. Simply allowing it to pass through 60% of the additional cost seems to abdicate the regulator's responsibility to find out what is going on, by investigating and answering this question, and to take remedial action if necessary.

Insofar as there may be a justification for greater capex, deriving from events subsequent to setting the price control, greater use of reopeners might be the way forward. The combination of these issues will benefit from discussion together.

vii) discretion on actual or forecast depreciation

I do not follow the precise calculations in this section of the AER's proposals. It is not clear to me at present why the assumption on depreciation influences NSP income within a period if the price control has been set in advance.

However, it seems that there is again a discrepancy between what was expected in setting the price control and the actual outcome. The parties might be asked: Is it helpful to prescribe automatic rules for this, regardless of the circumstances? Why not try to find out why there is such a discrepancy and deal with it appropriately?

viii) contingent projects, capex reopeners and pass-through events

AER makes the case for more flexibility on these issues. This would be consistent with regulation in the UK. Ofgem has indeed been specifying more precisely the provisions for reopening and pass-through. George Yarrow refers to the inadequacy of regulatory arrangements in Guernsey. One aspect of this was that the price control did not clearly specify the provisions for reopening and pass-through.

In general, this is the direction in which UK regulation has been moving. Initially, the thinking was to place all the risks on the regulated and newly privatised company, in return for a fixed price that took into account these risks. That seemed to me an effective way to bring home the change of status of these companies: they should no longer assume that they could simply pass all costs and risks on to customers or taxpayers.

However, it is expensive to put all risks on the company. It is more economic to ask which risks the company can more effectively bear, because it can deal most effectively with them, and which risks lie beyond its control. A company's cost of capital necessarily reflects the risks to which it is exposed. Removing risks that are beyond the company's control will reduce its cost of capital, and should thereby reduce the prices charges to consumers. Hence the calculation of cost of capital needs to take into account the nature and extent of reopeners and pass-through terms.

The balance here needs to be carefully assessed. If too many items are put into the reopener and pass-through categories, this will further pull down the allowed rate of return for the company but increase the risks and costs to customers. That in turn would be distorting in the opposite direction.

With more extensive use of reopeners and pass-through, there is less case for NSPs to overspend or underspend against forecasts. The regulator can be accordingly be tougher both in setting these targets and in enforcing them. In general, there is a move towards regulatory arrangements that are more like other commercial contracts. The parties might be asked to discuss the pros and cons of such developments. Again, this may be an area where greater customer involvement could be relevant and helpful.

ix) related party margins and capitalisation changes

Regulators are bound to have a concern that regulated companies might favour their own associated businesses. Arrangements that might be adequate if a regulated company is dealing with another company will not necessarily be sufficient if that other company is in the same ownership. AER's proposal therefore seems reasonable. However, it is a relatively technical issue on which I have no particular knowledge or ability to comment. There may be scope to compare the proposed charges against market levels?

x) flexibility to introduce other incentive schemes

UK experience suggests there is much scope for innovation here. Admittedly, regulators have limited knowledge, and there is a question how far the consequent extension of regulation is desirable. Not all schemes will work out as hoped, but it is possible to revise them over time.

In practice, other parties as well as regulators have made considerable contributions to designing incentive schemes. This is particularly the case in the UK airport sector. It is also a view expressed to me in the UK energy sector: that other companies and users of networks would have significant useful experience to apply to the design of incentive schemes. There is also an important potential role for customers and users to indicate where and why there should be an incentive mechanism, as well as to help design it.

AER's argument (s 6.8.2) about the limitations of present rules sounds plausible. As noted earlier, it seems in fact a limitation of the whole regulatory framework in Australia: frozen in time, reflecting the conditions and expectations at the time it was designed, but inflexible and not conducive to innovation. Schemes often need to be tailored to particular companies/customers/issues. My impression is that the AER's proposals are sensible, and reflect the way that regulation is developing elsewhere. However, the views of all parties need to be canvassed.

One submission (ETSA Utilities) suggests that giving AER greater discretion to introduce incentive schemes should be accompanied by supplemented decision criteria for AER. Two of these criteria seem redundant (eg desirability of simple-to-administer schemes, and not putting safe and reliable operation of the network at risk). The requirement that any scheme be symmetric in nature would be unduly restrictive and likely to stifle innovation. For example, the early incentive schemes on National Grid as System Operator were asymmetric because there was no prospect of an acceptable scheme that was symmetric. The Rules contain sufficient criteria already, and it would seem unnecessary and unduly bureaucratic to introduce more.

xi) shared assets used for other purposes

As with related party margins, regulators must be alert to the possibility that one set of customers will be favoured or penalised relative to another set. AER's proposal therefore seems sensible, and consistent with regulatory practice in the UK, but I have no specific knowledge on this matter.