Planning and Governance Arrangements for the National Transmission Grid

Final Report

Firecone Ventures Pty Ltd

December 2006

Disclaimer

Firecone Ventures Pty Ltd (including the directors and employees) makes no representation or warranty as to the accuracy or completeness of this report. Nor shall they have any liability (whether arising from negligence or otherwise) for any representations (express or implied) or information contained in, or for any omissions from, the report or any written or oral communications transmitted in the course of the project.

EXECUTIVE SUMMARY

Overall approach

This report assesses the current governance framework for electricity transmission in Australia, and possible improvements to that framework.

We start by defining criteria which can be used to assess the current framework. We then describe the current framework, assess its performance, and consider options for improvement.

The criteria we use are based on those set for ERIG as a whole. We have focused on ensuring efficient investment and operations of the network, and clarity and transparency for other market participants.

The governance framework determines how transmission investments are planned and made and the network is operated. In competitive sectors of the economy, these decisions are largely determined at company level. In regulated sectors, they are also affected by the regulatory framework which defines the company's obligations, and the revenues they receive, and so affects incentives at company level.

We have therefore taken the governance framework to include the nature of the transmission companies; their regulatory obligations; the arrangements for planning within and between regions; the form of economic regulation; and the nature of the regulator. Each of these is described in turn.

The report also assesses the performance of the current governance framework. This assessment of performance is brief, as this analysis is being led by CRA.

We then identify options for improvement, in response to apparent problems with the current regime. These combine changes to the different elements of the governance framework, as defined above, into a limited number of internally consistent options.

Current framework

The NEM has evolved from a set of State-based integrated power utilities to a competitive market covering the Eastern seaboard. State-based dispatch has been replaced by central dispatch across the market. NEM-wide institutions have been established to set policy, operate the market, set the market rules and regulate the transmission network.

The transmission grid has evolved in a similar manner. Power networks were originally State-based, then weakly interconnected, and now have strong interconnection. Decisions on transmission investment in one State heavily affect efficient investment in another.

The governance framework for transmission has not evolved in the same way and remains highly regionalised. There are six transmission network service providers, predominantly State-owned. They respond to planning standards defined at State level, with differing form and different levels of detail and clarity.

There are two different regulatory models – a standard CPI-X model, and a model relying on procurement by a statutory authority. There have also been investments under a third, unregulated, model. Although there is a single national regulator, regulation is applied sequentially to TNSPs in each jurisdiction, increasing the difficulties of applying a consistent and effective regulatory constraint. The nature of the constraint applied by the AER differs significantly between VENCorp and other TNSPs.

There have been attempts to offset this regionalised approach, in particular by:

- imposing obligations (the "Regulatory Test") on TNSPs to appraise possible interconnector investments in a way which takes account of their NEM-wide impacts. This may have improved the consultation processes over transmission investment. However, the process has no linkage to the revenues that TNSPs earn, or to their future regulatory asset base. It has not altered the incentive structure for TNSPs, and so is unlikely to have had a significant impact on investment decisions, and

- establishing an Annual National Transmission Statement. This has provided an independent national view of transmission requirements. While this is of benefit, and could be further developed, it has not altered accountabilities and incentives for transmission investment.

This highly regionalised approach to transmission undoubtedly results in some inefficiency in investment, although it is hard to quantify or demonstrate that inefficiency. It also creates risk and uncertainty and makes Australia less attractive to international investors. This perception of risk is increased by the joint ownership of transmission and generation by several State Governments.

Future options

We have considered three broad options for the future framework – modify the status quo, strengthen the regulatory regime, and introduce a single NEM-wide entity to take investment decisions.

The key elements of these options would be:

- *Modified Status Quo:* the establishment of a National Planner to disseminate information.

- *Stronger National Regulation:* link the regulatory constraint more strongly to efficient NEM-wide investment through the application of simultaneous five yearly revenue caps for all TNSPs. This would be supported by a National Planner to provide strong and well-informed independent advice on efficient investment across the NEM

- *National Procurement of Transmission:* establish a NEM-wide entity responsible for making decisions on transmission augmentations. As a result, NEM-wide costs and benefits could be internalised within the company. Our preferred structure for this entity would be a not-for-profit entity with the corporate governance – rather than external regulation – as the principal driver for efficient decision making.

A further change which has been proposed is that there should be independent conduct of the Regulatory Test by the National Planner, which might be combined with an ability to direct TNSPs to undertake investments which pass the Regulatory Test. For reasons set out in the report, we think this is inconsistent with the regulatory framework, and would lead to undesirable split accountability. And as a practical matter, there appears to be little evidence of a problem of underinvestment.

Transparency would be increased through the more clearly defined planning standards for TNSPs. This could be introduced under any of the options above. It would not require a move to a single form of planning standard.

The NEM will always be a relatively thinly populated and dispersed electricity market. This means that generators will continue to be exposed to higher levels of risk from the capability of the transmission system than they are in more densely populated markets, and more densely meshed transmission networks.

Transmission users have no direct representation in any of the market institutions. The NEM should develop institutional models which increase user involvement in deciding transmission investments. This would be a significant change to current arrangements, and should be trialled and developed over time. It could be introduced as an independent measure, regardless of the decision on other issues raised in this report. However, it would be more easily combined with either the second or third option considered above.

Recommendation

When Firecone considered these issues in 2003, we recommended continued reliance on a regionalised model, provided there was evidence of an effective regulatory constraint.

There is reason to doubt that the regulatory constraint is – or can be – effective in promoting national efficiency across the transmission grid, for the reasons described above. In addition, proposed developments in the Rules are likely to reduce the regulatory risk faced by TNSPs, reduce their efficiency incentives, and weaken the ability to impose an effective regulatory constraint.

These developments may make it harder to offset the inefficient investment which is likely to result from a regionalised approach to transmission. This strengthens the case for a move to an entity which determines and procures transmission investment across the NEM as a whole. This model should be combined with end-user representation on the board of this entity.

These options should be set out in a further consultation paper, to determine the views of market participants – and in particular potential generation investors – before reaching a final conclusion.

The establishment of more transparent planning criteria, and the development of a stronger national transmission planning capability, should be introduced regardless of the decision on the broader governance framework for transmission.

Table of Contents

1 Introduction

1.1 Scope of work

This document sets out Firecone's draft report to the Energy Reform Implementation Group (ERIG) on the planning and governance arrangements in the National Electricity Market (NEM).

ERIG has sought consultancy advice on the governance framework for the transmission grid. The Terms of Reference for that work are attached at Annex 1. Following receipt of proposals, ERIG decided to split the assignment between two companies.

Charles River Associates (CRA) is addressing elements 1 to 8 of the Terms of Reference (TOR). This focuses on whether the regulatory arrangements have delivered efficient outcomes, on the role of the Regulatory Test, and on possible changes to regulatory or pricing mechanisms.

Firecone is addressing elements 9 and 10 of the Terms of Reference. Our scope of work covers:

- *National planning arrangements*: is there a need for enhanced national planning arrangements, and if so what role and functions should be assigned to the entity concerned. The TOR distinguished between disseminating information; co-ordinating analysis; identifying new investment opportunities; reviewing proposals; and directing that transmission investment proceed

- *Governance options*: the governance options for transmission planning, and the strengths and weaknesses of each. This includes the interaction with the broader regulatory regime; the relationship between asset ownership, investment decision making and planning; and the interaction of planning arrangements with the Regulatory Test.

In order to describe and assess arrangements for national planning, and governance options, it is necessary to describe the overall governance framework and the role that planning plays within it.

We have interpreted the governance framework to include the nature of the transmission network service providers; the planning standards applying to them; the current arrangements for co-ordination; the nature of the regulatory agency; and the form and conduct of regulation. This is described more fully in section 2.

1.2 Structure of the report

The report is structured as follows:

- Section 2 outlines the nature of the overall governance framework for transmission

- Section 3 sets out assessment criteria, to assess performance of the current governance framework and to select between options to improve that framework

- Section 4 describes the current framework. It looks in turn at:

    - The nature of the regulated entities

    - The form and content of planning standards applying to those entities

    - Planning arrangements, including arrangements for national planning

    - The nature of the regulator, and

    - The form and conduct of economic regulation

- Section 5 provides a brief assessment of the current framework. The assessment is based on first principles, rather than on quantitative analysis

- Section 6 considers possible improvements to the governance framework, and

- Section 7 sets out our conclusions

2 Governance framework

2.1 Interaction between planning and governance

Firecone is addressing elements 9 and 10 of the Terms of Reference. Our scope of work covers:

- *National planning arrangements*: is there a need for enhanced national planning arrangements, and if so what role and functions should be assigned to the entity concerned. The TORs distinguished between disseminating information; co-ordinating analysis; identifying new investment opportunities; reviewing proposals; and directing that transmission investment proceed

- *Governance options*: the governance options for transmission planning, and the strengths and weaknesses of each. This includes the interaction with the broader regulatory regime; the relationship between asset ownership, investment decision making and planning; and the interaction of planning arrangements with the Regulatory Test.

In order to describe and assess arrangements for national planning, and governance options, we have considered the overall governance framework, and the role that planning plays within it. The rationale for this approach, and its implications, are described in this section.

ERIG is charged with achieving a truly national transmission grid. This requires that decisions on investment in and operations of the grid are taken in light of the costs and benefits for all market participants across the grid as a whole, rather than seeking to optimise the grid on a regional basis.

There are reasons for questioning whether this will be achieved through current arrangements:

- The obligations of the transmission entities are defined at State level

- The companies and other entities determining transmission investment and operations are mostly owned by State Government. All of them limit their investment and operating decisions to one State

- Planning is mainly conducted at a regional level, although an Annual National Transmission Statement has recently been introduced, and

- While the transmission regulator is a single national entity, it carries out sequential regulatory reviews on a State-by-State basis.

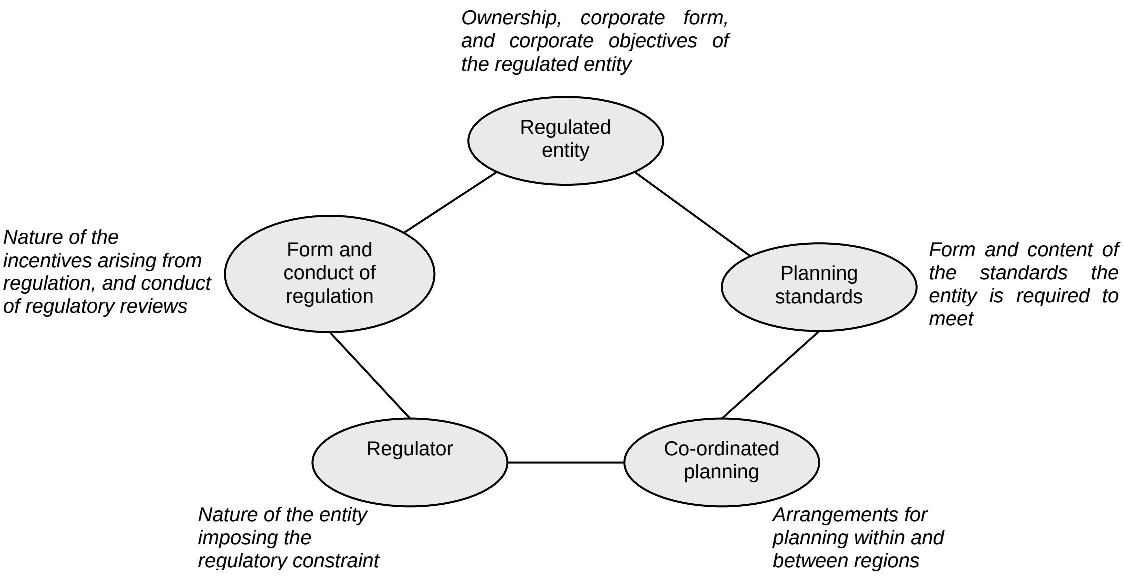
A focus simply on planning would not effectively address ERIG's objectives. To be simplistic, it would be possible for a new entity to produce an excellent plan for investment and operations of the national grid, and to have no effect on actual investment and operations.

We have therefore considered not simply how planning is conducted, but how it interacts with the investment and operating decisions of the entities who deliver transmission services. As these entities are regulated, this requires considering both of the entities themselves, and of the impact of regulation on the incentives that they face.

2.2 Scope of the governance framework

The elements that we have included within the governance framework are summarised in Figure 1.

Figure 1: The governance framework



The elements are:

- the ownership, corporate form and corporate objectives of the regulated transmission body. This has a bearing on its incentives to pursue efficiency. The ownership also has a bearing on market perceptions of its conduct

- the planning standards, which broadly define the outputs which the regulated entity is required to provide, and strongly affect its investment decisions

- the arrangements for planning, both within and between regions

- the nature of the entity imposing the regulatory constraint; and

- the form of regulation, and the way in which regulation is undertaken.

This approach allows us to consider how far different approaches to national planning support ERIG's objectives, by looking at their likely impact on the incentives faced by transmission businesses, and so their impact on investment and operating decisions.

Consideration of planning alone – without this linkage to investment and operating decisions – would not assist ERIG in identifying a preferred way forward.

3 Assessment criteria/objectives

A critique of the existing governance framework, and an assessment of possible alternative arrangements, requires clear and consistent criteria for evaluation. This section sets out how we have approached that task.

ERIG is required to report to COAG on:

> *"proposals for achieving a fully national transmission grid, including the most suitable governance and transitional arrangements having regard to COAG's objectives of achieving a truly national approach to the future development of the electricity grid, the legitimate commercial interests of asset owners, and the need to promote investment that supports the efficient provision of transmission services."*

Our focus is on the governance and planning arrangements, and their contribution to ERIG's objective of achieving a fully national transmission grid. In particular, we have considered how investment decisions are planned and made, given the roles and incentives of different parties under the governance framework.

The NEM is served by a single, integrated transmission grid. As discussed elsewhere in this report, investment in one region of the NEM can have a material impact on costs and benefits in other regions. Efficient transmission investments will need to take account of the costs and benefits across the NEM as a whole.

Transmission is an element of an integrated supply chain. The objective should be to ensure efficiency across that supply chain, not simply in the transmission segment. This requires consideration of the interaction between transmission investment and the competitive sectors of the supply chain, and in particular generation.

The NEM has a 'merchant' model for generation, with generation investors being exposed to the financial outcome of their performance in the market. This is combined with a dominant 'regulated' model for transmission. Investors in transmission are not directly exposed to a competitive market, although they are exposed to regulatory incentives related to their operational performance.

The most effective interaction between these models is achieved when 'merchant' investors have reasonable clarity and transparency on the basis for their investment, and the risks that they face. This is best achieved by reasonable transparency over the basis for transmission investment. Again, this needs to be across the NEM as a whole, not simply within one region.

Our assessment of the current governance framework, and of possible alternatives, is therefore based on:

- *Dynamic efficiency*: does the framework facilitate least cost investment across the electricity supply chain, and

- *Reasonable certainty:* does the framework provide reasonable certainty for other market participants, and in particular generation investors

The main impact of the planning and governance framework is on investment decision making. The framework may also affect productive efficiency, and the costs associated with a given investment program. This will include:

- *Direct costs:* does the framework ensure that the direct costs of implementing a given transmission investment are minimized ? and

- *Indirect costs:* does the framework ensure that indirect costs – in particular, the costs of outage for other market participants are minimized for a fixed capital stock?

This short term operational efficiency is affected by the management of the transmission company (and in particular whether they are properly incentivised to minimise costs). It is also affected by the incentives provided by the regulator to minimise costs for other market participants, in particular by ensuring high levels of network availability at periods when this is of greatest value.

Our assessment pays less attention to the issue of short term operational efficiency. The importance of good incentives for TNSPs to minimise direct and indirect costs is widely recognised, and an important element of the overall regulatory framework. However, the AER is already actively managing the development of an appropriate incentive framework, within the rules established by the AEMC. The main area where ERIG can add value is therefore by considering ways in which the overall governance framework could promote efficiency and transparency in transmission investment.

4 Current framework

The framework for regulation of electricity transmission in Australia draws on many aspects of the regulatory regime in Great Britain. In particular the regulatory framework for most – but not all - TNSPs relies on periodic revenue caps, established by an independent regulator on the basis of a cost build-up. This chapter compares the Australian arrangements to what we term the 'standard model', loosely based on the British regime. This is not intended to imply that the British approach is a desirable model, but is intended to establish a means of critique and comparison.

The 'standard' model includes a number of key elements:

- *Regulated company:* the regulated company is assumed to have strong incentives to maximise profits. Where outputs are defined, and revenues are capped, this is achieved through cost reduction.

- *Regulator:* the regulator is assumed to have an ability to impose a cap on revenues, based on reasonably authoritative analysis and independent planning of the efficient costs of delivering transmission services over a five year period, and

- *Incentives:* the combination of a revenue cap with defined outputs is akin to a fixed price contract, with similar incentives for cost reduction. In the 'standard' model, this is combined with a strong operational incentive.

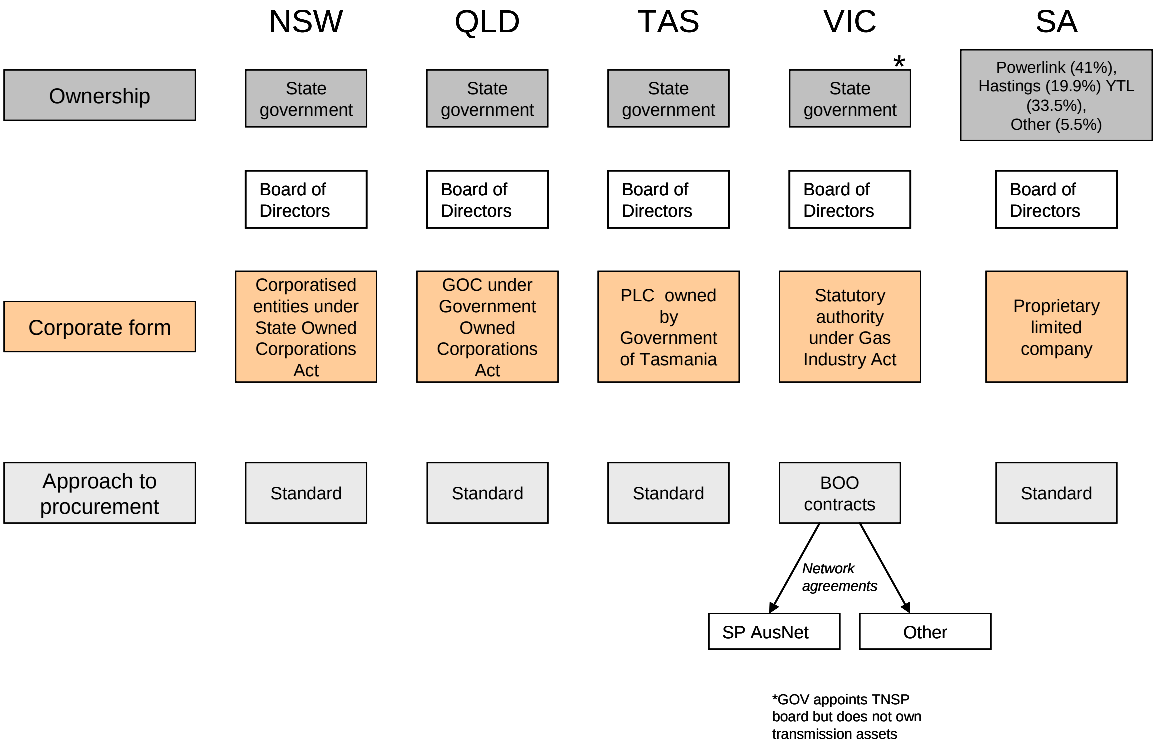
The Australian regime diverges significantly from the 'standard' approach described above in some areas. These differences are described in the rest of this chapter which focuses in turn on the nature of the regulated entities, planning criteria, planning co-ordination, the nature of the regulator and finally the form of regulation.

4.1 Nature of the regulated entities

The 'standard' model assumes a profit maximising business. Profit maximisation may not deliver economic welfare, due to the monopoly characteristics of transmission assets. The public interest is therefore protected by prices and outputs which are to some degree imposed by an economic regulator (for example, through a cap on revenues and an obligation to meet planning standards) rather than through the market.

In the NEM, the regulated entity differs from the profit-maximising assumption in the 'standard' model. These differences can be specified in terms of ownership, corporate form and approach to procurement as illustrated in Figure 2.

Figure 2: Ownership, corporate form and approach to procurement



The differences with respect to ownership, corporate form and the approach to procurement are described below.

4.1.1 Ownership and corporate form

Government ownership and independent regulation are in many respects alternative means of addressing similar objectives. Where Government appoints the board members, it has an ability to ensure that the company protects the public interest. Conversely, if the Government simply wants a business to maximise profits, it has no need to have an ownership interest, since that behaviour could be expected under private ownership. The 'standard' model assumes private or public (non-government) ownership.

In the NEM Powerlink, Energy Australia, TransGrid and Transend are wholly government-owned. ElectraNet and SP AusNet are both privately owned businesses. VENCorp is a not for profit statutory authority. Unlike other TNSPs, it does not own transmission assets.

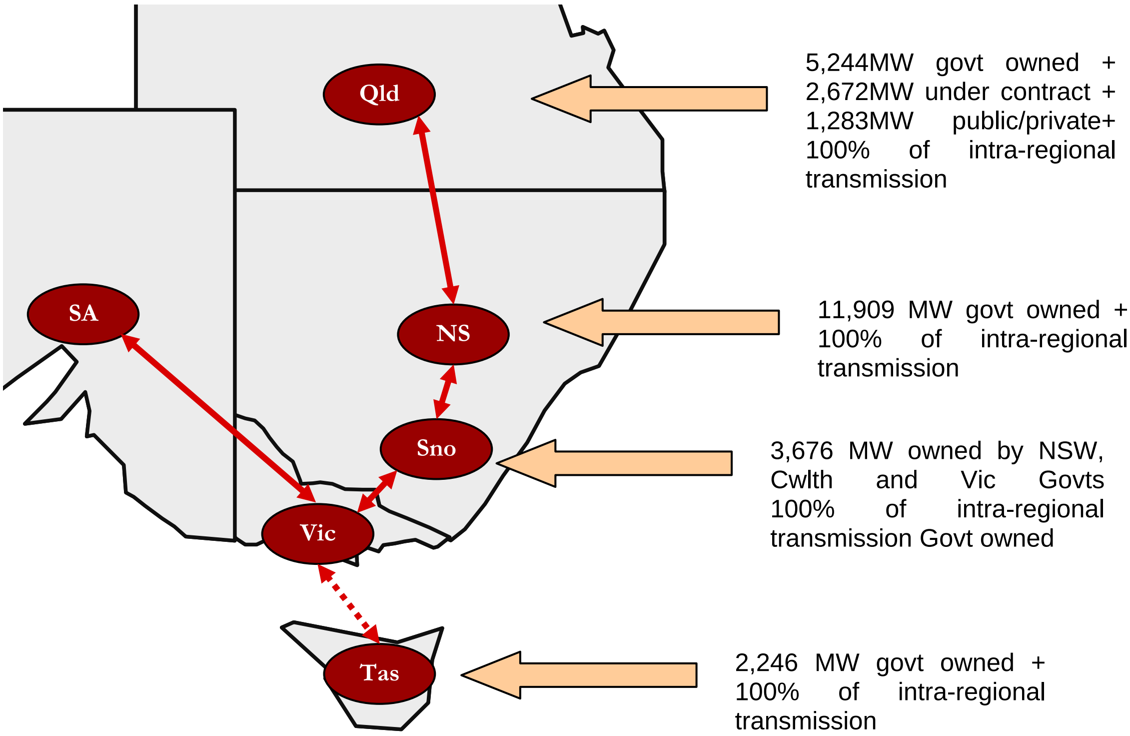
All TNSPs other than VENCorp are for-profit businesses. As set out in Table 1, financial returns are usually identified as just one of many corporate objectives. There also appears evidence that these TNSPs are – understandably – focused on efficient delivery of the Government's objectives over and above profit maximisation. VENCorp is a not for profit statutory authority.

In New South Wales, Queensland and Tasmania, Government ownership of transmission is combined with ownership of generation. The extent of cross-ownership is shown in Figure 3.

The combination of Government ownership with independent economic regulation is not uncommon. It is for example common in water in Australia, the dominant model in telecoms (although this is changing) and it also used in some aspects of rail.

However, cross-ownership of regulated and competitive businesses is a rarer model. For example, although there is significant Government ownership of rail track, in most (but not all) jurisdictions this has been accompanied by Government withdrawal from competitive rail freight services.

Figure 3: Generation and Transmission cross-ownership



All TNSPs place a high value on the delivery of reliable networks – this is their primary business objective. A brief comparison of their stated corporate objectives and reported financial outcomes as set out in Table 1

Table 1: TNSP corporate and financial objectives

	Main corporate objectives
Powerlink	Safety, reliability, cost effectiveness, reasonable returns to owners. Return on equity around 6.4% p.a. over last three years.
TransGrid	Efficient long term development of the transmission network. Government-determined target return on equity is below 6.88% p.a.
VENCorp	Efficient and effective delivery of energy.
ElectraNet	"The company's key business objective is to be an outstanding investment for our shareholders while maintaining a BBB+ credit rating"
Energy Australia	Safety, reliable networks, social responsibility, environmental protection and government-determined target return on equity of 7.4% p.a.
Transend	"Efficiently provide a reliable and secure transmission service at a cost commensurate with appropriate and sustainable returns to shareholders." Return on equity in 2005 was 4.8% p.a.

4.1.2 Approach to procurement

All TNSPs other than VENCorp have a standard procurement model whereby the TNSP owns the assets that it uses. The recovery of the expenditure in developing and operating these assets is recovered from customers through a cap on regulated revenue set by the regulator. In this respect, the arrangements for these TNSPs are consistent with the 'standard' model.

Although these TNSPs own and operate their assets, many will let major projects through competitive tender. The extent to which they use private contractors, and the level of risk transfer under the contracts, vary by TNSP.

By contrast, VENCorp offers all significant transmission projects on competitive tender, and does so under build-own-operate contracts. Since 1997 it has let seven such contracts, of which five have been secured by SP AusNet.

The combination of its not for profit status, and its procurement approach, mean that a 'standard' regulatory model cannot be applied to VENCorp's transmission functions. The implications are discussed below.

4.2 Planning criteria

The 'standard' model requires clear planning criteria as the basis of investment planning by the transmission company; the development of revenue caps by the regulator; and to provide transparency for other market participants.

Schedule 5.1.2.2 of the Electricity Rules is a step towards the harmonisation of planning criteria around the NEM, by specifying a minimum standard of service. It states that the standard of service to be provided at each connection point must include a power transfer capability "*such as that which follows*":

"(a) In the satisfactory operating state, the power system must be capable of providing the highest reasonably expected requirement for power transfer requirements … at any time;
(b) During the most critical single element outage, the power transfer available through the power system may be:

(1) *zero*
(2) *the defined capacity of a backup supply*
(3) *a nominated proportion of the normal power transfer capability (e.g. 70%); or*
(4) *the normal power transfer capability of the power system.*"

Clearly this Rule can provide for very different standards of supply.

In addition to the Schedule 5.1 rules, the Electricity Rules also require each NEM jurisdiction to nominate a body responsible for transmission planning within their State. Jurisdictions vary in how they allocate this responsibility. In Queensland, New South Wales and Victoria, the planning criteria are established by the TNSP itself under delegated authority from the state governments. In Tasmania, the Reliability and Network Planning Panel (RNPP) has advised the Office of Tasmanian Energy Regulator (OTTER). The RNPP's recommended criteria are yet to be reflected in OTTER regulations. The proposed standards include provision for government to be formally involved in evaluating the merits of all projects greater than 10 MW.

In South Australia the criteria are established, on the advice of the Electricity Supply Industry Planning Council (ESIPC), in the Electricity Transmission Code administered by the Essential Services Commission of South Australia, under State legislation. The role of government in the assessment, evaluation and enforcement of criteria varies amongst States.

The State-based planning criteria that apply in the different jurisdictions are summarised in Table 2.

Table 2: Jurisdictional planning criteria

Victoria	All significant transmission augmentations are subject to a cost/benefit assessment. VENCorp conducts a cost/benefit analysis that compares the cost of investment against possible benefits. Possible benefits may include: value of load that would otherwise be curtailed, additional cost of ancillary services, possible reduction of fixed and variable generation costs, reduction in cost of losses, benefit of deferring other network investments.
Tasmania	No credible contingency event (as defined by NEMMCO) will interrupt more than 25 MW of load. No single asset failure (such as a double circuit transmission line or substation bar) will interrupt more than 850 MW or cause a system black. Unserved energy related to a credible contingency must not exceed 300 MWh. Unserved energy as a result of asset failure must not exceed 3000 MWh. Where a network element has been withdrawn from service, the energy exposed to interruption must not exceed 18,000 MWh. In addition, projects worth more than $10m proposed to meet these criteria should be subject to consideration by the jurisdiction to take account of broader economic costs and benefits.
NSW	TransGrid is the Jurisdictional Planning Body and generally plans its network to an n-1 standard with variations from this standard in some circumstances.
QLD	Powerlink plans its network in accordance with its interpretation of Schedule 5.1 of the Electricity Rules. Section 34(2) of the Electricity Act 1994 requires the transmission entity to ensure, as far as technically and economically practicable, that the transmission grid is operated with enough capacity (and, if necessary, augmented or extended to provide enough capacity) to provide network services to persons authorised to connect to the grid or take electricity from the grid. In addition, Clause 6.2 of Powerlink's transmission authority (transmission licence) requires Powerlink to plan and develop its transmission grid in accordance with good electricity industry practice, such that power quality and reliability standards in the National Electricity Code are met for intact ("system normal") and outage conditions, and the power transfer available through the power system will be adequate to supply the forecast peak demand during the most critical single network element outage, unless otherwise varied by agreement.
SA	All connection points between the transmission system and transmission customers, generators or distributors are allocated to one of six load categories. The transmission service obligations are defined by category with category six requiring the highest standard and category one the lowest. Progressively higher levels of transmission line and transformer redundancy are required to serve connection points in higher load categories. Progressively quicker restoration periods are prescribed in the event of interruptions to supply in higher load categories. The highest category, category 6, applies to Adelaide Central only.

State-based criteria are focussed on reliability within each jurisdiction. Reliability outcomes are defined in a variety of ways including minimum network redundancy (New South Wales, Queensland), minimum network redundancy and minimum restoration times (South Australia), minimum network redundancy, maximum load to be interrupted and maximum unserved energy (Tasmania).

Reliability outcomes and planning criteria are formalised and codified to different degrees in each State. For example in South Australia, the planning criteria for Adelaide Central states that (inter alia) the TNSP (after 31 December 2011) must provide N-1 transformer capacity by means of independent and diverse transmission substations, one of which must be located west of King William Street. In Victoria on the other hand the criterion is more loosely defined as the need to develop networks to economically meet reasonable customer expectations.

The planning standards in Schedule 5.1 to the Rules are, by design, very flexible but this has left them open to different interpretations. This is illustrated by submissions in response to Powerlink's proposal to construct a new large network asset to address emerging issues in the Darling Downs area. VENCorp argued that Schedule 5.1 of the Code does not oblige Powerlink to ensure that peak demand can be supplied, and that an acceptable action to meeting the Schedule 5.1 network performance standards is to allow customer supply to be interrupted under a credible single contingency[1]. Powerlink disagreed with this interpretation of the Code obligations.[2]

Further, as provided by the Code, TNSPs may negotiate connection agreements that require the TNSP to deliver higher standards of reliability than specified in Schedule 5.1 to the Rules or in State-based legislation or licence conditions.

In addition, reliability obligations are set through different combinations of instruments in each jurisdiction. Interested parties must navigate a diverse range of regulations, publications and licences in order to ascertain the reliability obligations applicable to particular locations. Further, in some cases, reliability obligations are imposed by documents that are not readily available to other market participants and regulators. Queensland, for example, does not generally publish or make available copies of individual transmission authorities unless the holder consents.[3]

In all cases, interpretation of criteria involve consideration of numerous factors that interact in uncertain ways. Considerable judgement is often required on whether the network is compliant with criteria, and what type of investment should be made in order to ensure that it will be compliant in future. With the same criteria, different planners could come to significantly different conclusions, but equally with different criteria, similar investment decisions are nevertheless possible.

4.3 Planning co-ordination

The electricity transmission system is an integrated network. Changes to one part of the system can have significant impacts on transfer capacity in other regions. Efficient development of the network as a whole therefore requires transmission planning to be co-ordinated across the NEM.

In Great Britain, transmission planning decisions have been integrated (that is, conducted by one body) within England and Wales. Initially there was a need for co-ordination with two other network service providers covering central and northern Scotland. However, recent changes have resulted in a single entity responsible for planning decisions throughout Great Britain. The trend has therefore been towards unified decision making, within one transmission company, as a means of achieving co-ordination.

[1] VENCorp (2003) Submission to Powerlink

[2] Powerlink (2003) Final Recommendation: Proposed New Large Network Asset – Darling Downs Area.

[3] http://www.energy.qld.gov.au/electricity/licensing.htm

The NEM has always assigned prime responsibility for intra-regional planning to the TNSP. Initially, the NEM also had a formal structure for co-ordinating decisions on inter-regional augmentations. In March 2002, the NDR Code changes replaced this with a structure that allocated all investment responsibility to TNSPs, and encouraged co-ordination through information dissemination provisions.

Since then, there has been a gradual move back towards some degree of centralised co-ordination, through the ANTS, and a power to direct TNSPs to undertake the Regulatory Test. However, the overall framework remains a devolved one, with a limited role for co-ordinated planning. This evolution is described below.

4.3.1 Initial Structure

In the NEM - from the start to March 2002 - the Electricity Code dealt with the need for co-ordination by distinguishing between intra and inter-regional transmission planning and development.

TNSPs were required to conduct an annual planning review examining the adequacy of the transmission network in their region over a ten year planning period. Each TNSP was responsible for developing intra-regional augmentations in their area, subject only to the technical requirements of the Code. The TNSPs were required to satisfy a Regulatory Test for their intra-regional augmentation investments. It was unclear whether this was a necessary precondition for inclusion of expenditure in the regulated asset base. It was generally assumed that it was not a necessary pre-condition.

The Inter-regional Planning Committee (IRPC), which comprises representatives of NEMMCO and the jurisdictional planning bodies, was responsible for assessing the technical and economic merit of inter-regional augmentations proposed by TNSPs. Proposed inter-regional augmentations had to be approved by the IRPC as satisfying the Regulatory Test before they could be included in a TNSP's regulated asset base.

Inter-regional augmentations were not specifically defined. The Code did not make clear whether the amount to be included in the RAB was the amount specified in the Regulatory Test, or the actual cost of the project that was actually developed. Despite these points, the framework did establish a clear connection between the conduct and outcome of the Regulatory Test, and the regulatory regime for TNSPs.

4.3.2 NDR Code Change

The Network and Distributed Resources (NDR) Code Change package took effect in March 2002, and substantially changed the arrangements for planning regulated transmission within the NEM. These changes took away responsibility for network planning from NEMMCO/the IRPC. Following these changes there has been no formal obligation on any entity to plan, develop or oversee interconnectors.

In authorising the NDR code changes, the ACCC commented that

> *"The Commission supports the applicant's proposal that TNSPs should have prime responsibility for the planning and augmentation of networks as they are accountable for network performance levels. These accountabilities arise from the reliability standards contained in Schedule 5.1 of the Code, various State imposed standards, and duty of care obligations under common law to the extent that it applies[4]."*

At the time of the NDR Code changes it was recognised that reliance on completely regionalised planning may fail to deliver efficient expansion of the integrated transmission network across the NEM as a whole. The NDR Code changes introduced information provision mechanisms to encourage and facilitate co-ordination:

- TNSPs were required to publish the results of their annual planning reviews in an Annual Planning Report, and include information about proposed network augmentations in that Report.

- The IRPC was required to publish an Annual Interconnector Review, containing an assessment of the need for inter-regional augmentations and information on possible inter-regional augmentation options. The IRPC was also tasked with defining reliability augmentations, defining when one TNSP's transmission plans are likely to have a material impact on other TNSPs, and producing a technical augmentation report on request by a TNSP, if TNSPs were unable to resolve differences relating to proposed interconnector developments. The augmentation technical reports are meant to cover

    - the performance requirements for the equipment to be connected;
    - the extent and cost of augmentations and changes to all affected transmission networks; and
    - the possible material effect of the new connection on the network power transfer capability including that of other transmission networks.

- TNSPs were required to apply the Regulatory Test to all proposed new network assets with varying information disclosure and consultation requirements, depending on whether the proposal is for a new small network asset or a new large network asset.

The NDR Code change therefore broke the link between the Regulatory Test and the determination of the regulated asset base in respect of interconnector investments. There was no previous link between the Regulatory Test and the regulated asset base for other investment.

The NDR Code changes also put in place other mechanisms to encourage efficient network planning including:

- Any interested party could dispute the TNSPs economic assessment of new large network asset proposals (including the network alternatives considered, their relative ranking, and the basis on which the TNSP has assessed that the proposed option satisfies the Regulatory Test).

- Under the ACCC's Draft Regulatory Principles which applied at the time of the NDR Code changes, TNSPs were exposed to the risk that the ACCC could write-down the

[4] ACCC (2002) Determination: Network and Distributed Resources code changes.

value of previous investments (called "optimisation") thereby ensuring that customers would not be burdened with expenditure that the ACCC considered to be inefficiently incurred.

4.3.3 Subsequent developments

Since the NDR Code changes, there have been developments in information provision and the operation of the Regulatory Test that affect NEM-wide co-ordination of transmission planning:

- The Annual National Transmission Statement (ANTS) was first published in 2004, replacing the Annual Interconnector Review. The ANTS is the outcome of NEMMCO's annual national transmission review. It provides an integrated overview of the current state and potential future development of national transmission flow paths (NTFPs). The ANTS includes a review of forecast constraints on NTFPs; and options that, in NEMMCO's reasonable opinion, are technically capable of relieving those forecast constraints.

- Changes have been made to the process and appeal rights in respect of Regulatory Test outcomes. Now, only projects greater than $10m that are assessed under the market benefits limb of the test, can be appealed to the AER.

- In May 2005, the MCE decided that the AEMC should have the power to direct a relevant party to undertake the Regulatory Test. At the time of writing, this decision is yet to be reflected in changes to the Electricity Rules.

In other words, these changes have left in place the reliance on devolved regional planning, and added to this some modest steps to provide information; allow appeal; and enable the AEMC to direct a TNSP to appraise a project.

4.4 Nature of the regulator

The 'standard' model envisages a single, independent expert economic regulator, vested with a high degree of autonomy in the application of economic regulation of monopoly transmission services providers. In the NEM, a number of institutions and mechanisms all play a significant role in the economic regulation of TNSPs:

- **The Australian Energy Regulator**. This is a three person commission, and is a constituent part of the ACCC. Its main regulatory responsibility is to implement five-yearly revenue cap decisions covering the provision of regulated transmission services.
- **The Ministerial Council Energy (MCE)**. This is the national policy and governance body for the Australian energy market. It was established by the Council of Australian Governments and comprises the Ministers responsible for energy from all States, Territories and the Australian Government. Its decisions can have a significant influence on economic regulation. For example, it has established principles for the Regulatory Test, instructed changes to the operation of the Regulatory Test and instructed the AEMC to direct that a relevant party undertakes the Regulatory Test.

- **The Australian Energy Market Commission.** This is a three person commission, reporting to the MCE. Its functions include writing the National Electricity Rules. To-date this has involved a detailed review and re-design of key regulatory mechanisms such as capex incentives, the specification of how efficient investment is to be assessed by the AER, and instructions for the AER to make other changes subject to specific guidelines. The AEMC has also proposed some changes to the detailed application of the Regulatory Test. It is also authorised to direct a relevant party to undertake the Regulatory Test where it sees fit.
- **State Governments.** State Governments are responsible for determining the outputs (level of reliability) that TNSPs are required to achieve. As described earlier this is typically specified in terms of reliability criteria, but may also involve direct government consideration of specific projects.
- **The Inter-Regional Planning Committee.** This is a committee convened by NEMMCO, and represents the TNSPs in each NEM region. As described earlier, its formal duties extend to defining when investments in the network have a "material inter-regional impact", and producing a Technical Augmentation Report, if requested to do so. Like the Regulatory Test, such reports have no direct bearing on regulated assets or revenues, but are intended to be a last resort mechanism if TNSPs are not able to agree amongst themselves, to make the impact of possible interconnections clear. To-date no Augmentation Technical reports have yet been produced.

4.5 Form and conduct of regulation

The 'standard' model creates efficiency incentives by periodically resetting a cap on the revenue that can be recovered from consumers through regulated charges, combined with a specification of the standards to be met. Typically the regulated entity retains some or all of the difference between the expected expenditure and the actual expenditure, for the period of the regulatory control. This gives it an incentive to minimise costs.

The regulated entity may also be subject to operational incentives to make transmission capacity available at times when it is of greatest value; and/or reliability incentives related to the quantity of unserved energy.

The regulatory typically involves the regulator and regulated entity in a negotiation that results in the specification of the regulated asset base and the outputs to be delivered. Agreed maximum levels of operating and capital expenditure are reflected in annual revenue caps. Typically revenues are stated as annual limits and are not associated with specific projects or programs.

The expenditure review process typically involves engineering-based models of replacement capital expenditure, and demand-related expenditure. While the assessment can involve forensic examination of specific proposed investments, this is typically not done. Instead, the expenditure review process usually relies on high level engineering models, and the use of benchmarks as far as possible.

The form of regulation implemented in the NEM appears at first sight to be similar to the 'standard' CPI-X incentive model: the AER resets the regulated revenue cap on the basis of a negotiation with the regulated entity. However, in reality the form of regulation has tried to accommodate both the 'standard' model, and project-specific reviews of individual projects through application of the Regulatory Test. As discussed below, this has resulted in significant confusion over the form of regulation.

The rest of this section examines revenue cap regulation (as it applies to all TNSPs other than VENCorp), the public procurement model operated by VENCorp, the Regulatory Test and finally the conduct of regulation.

4.5.1 Revenue caps

The 'standard model' entails relatively high-powered incentives to reduce opex and capex costs below the regulatory allowance. These cost savings are – at some point - passed on to consumers through lower expenditure allowances and/or a lower regulated asset base in the subsequent regulatory periods.

In Britain, these expenditure incentives have been accompanied by substantial financial incentives on the transmission service provider to manage power system operations (including the cost of constraints, transmission losses and ancillary services) and more recently substantial financial incentives related to the amount of unserved energy.

In the NEM, incentives to reduce opex and capex are less powerful than those in the 'standard model'. The AER has – correctly - described its expenditure efficiency incentives as low-powered. The service standard incentives are also considerably less powerful than in the standard model, with a maximum of 1% of annual revenue at risk, spread across several service output measures (although with an intention to increase the scale of this incentive).

Table 3 tracks the development of revenue cap regulation since the beginning of the NEM. The arrangements described in Table 3 are applicable to all TNSPs other than VENCorp. For SP AusNet, the predominant owner of transmission assets in Victoria, regulatory incentives are in place for capex and opex associated with asset replacement, maintenance and operations.

Table 3: Revenue cap regulation in the NEM

	Draft Statement of Regulatory Principles (DRP): 1999 to July 2004.	**Statement of Regulatory Principles (SRP): Since December 2004.**	**AEMC proposed changes**
Operating expenditure incentives	Ex-ante target expenditure allowance for each year of revenue control. Starting value in year 6 has no defined relationship to historic opex in previous regulatory period.	Ex-ante target expenditure allowance for each year of revenue control with carry-forward mechanism to ensure constant power of incentive (proportion of savings to be retained by firm) over the regulatory period. Starting value in year 6 no defined relationship to historic expenditure in previous regulatory period, but AER will take account of historic expenditure. Provision for pass-through of some operating costs.	Unchanged, although AER instructed to re-look at carry-forward mechanism.
Capital expenditure incentives	Incentives are indeterminate. At the end of the regulatory period, capital	Value of asset base at the end of the regulatory period is based on depreciated value of actual expenditure during the regulatory period. This provides progressively	Similar to SRP but some aspect of design of contingent project mechanism changed. Re-

	expenditure during the period is subject to ex-post prudency assessment to determine whether it should be included in regulated asset base. Alternatively, the value of the asset base could be periodically revalued using depreciated optimised replacement cost i.e. without regard to historic expenditure.	weaker incentives over the course of the regulatory period ranging from around 35 cents in the dollar in the first year of the period, to 3 cents in the dollar in the last year of the regulatory period. In addition, provision was made for excluded projects (later renamed contingent projects) whereby additional capital expenditure could be approved during the regulatory period. Provision made to re-open cap during the regulatory period if there were on-off exogenous shocks.	opener mechanism similar to SRP but detailed application different.
Service incentives	None specified initially. At the end of 2003 an incentive was developed based on circuit availability, the number of loss of supply events and the duration of outages with maximum of +/- 1% of annual maximum allowed revenue at risk.	As before.	AER instructed to develop incentive for TNSPs to improve and maintain those elements of the transmission system that are most important to determining spot prices. Incentive should result in maximum adjustment of +/- 5% of annual maximum allowed revenue.
Determination of regulated asset base	Asset base subject to periodic revaluation or based on the roll-forward of historic depreciated expenditure.	Opening asset base at start of regulatory period rolled forward to end of regulatory after adjusting for CPI and depreciation. Excluding arrangements for contingent projects, the value of actual expenditure during the period is calculated based on the depreciated value of actual cash expenditure during each year of the period.	As before.

4.5.2 Public procurement

In Victoria, VENCorp is the TNSP. It plans all augmentations to the transmission network and issues tenders to procure capacity. Since 1997 it has issued seven tenders, of which SP AusNet, the dominant transmission operator in Victoria, has won five. These tenders are typically Build-Own-Operate contracts.

VENCorp enters network agreements to ensure that the services associated with those assets are provided over the useful life of those assets. VENCorp determines transmission use of system charges in accordance with the Electricity Rules, to recover the cost of these investments from transmission users in Victoria. There is no regulatory control by the AER of these charges.

VENCorp's main network agreement is with SP AusNet. Included in this agreement is a transmission operating incentive that encourages SP AusNet to ensure that assets are available, with higher incentive payments applicable at certain times.

VENCorp's own expenditure is subject to regulatory oversight by the AER through five-yearly controls. However, the arrangements essentially result in the recovery of their actual expenditure during the regulatory control period. Unlike the regulatory controls determined by the AER for other TNSPs, there are no efficiency incentives in the controls applicable to the VENCorp. As VENCorp has no regulatory asset base, it also has no ability to bear significant financial incentives and risks.

4.5.3 The Regulatory Test

The Electricity Rules require TNSPs to apply the Regulatory Test to all augmentation projects greater than $1m, with a more comprehensive test for projects greater than $10m. Table 4 summarises the development of the Regulatory Test since the start of the NEM.

Table 4: The development of the Regulatory Test

	Up to November 1999	**November 1999**	**March 2002 (Network & Distributed Resources Code changes)**	**August 2004 (ACCC review of Regulatory Test)**
What is the test?	Is cost of proposed project less than benefit to customers?	Find project that maximises economic benefits and minimises costs.	For reliability projects, test is to find project (including non-network projects) that minimises cost to meet reliability standards. For other projects test is to find project (including non-network projects) that maximises economic benefit. Augmentations less than $1M not formally tested but must be identified in Annual Planning Report.	As before but optional inclusion of competition benefits; and distinction between inter and intra-regional augmentations removed from test (to conform to Code).
Who sets the test?	NEMMCO	ACCC	As before	As before
Who does the test?	NEMMCO (IRPC) for projects that have material inter-regional impacts. TNSP for all other network augmentations.	As before	TNSP for all augmentations.	As before
Who determines if test passed or failed?	NEMMCO (IRPC) for projects with material inter-regional impacts. NEMMCO decision can be appealed to National Electricity Tribunal. TNSPs self-assess other projects.	As before	TNSPs self-assess. Code participants can appeal outcome of test for non-reliability projects to ACCC.	As before
What does passing/ failing the test mean for regulated revenues?	If project passes test, cost to be added to RAB (but ambiguous whether it was actual cost of project or cost envisaged at time of test). Nevertheless, ACCC retained right to ex-post optimisation.	As before.	No formal relationship between outcome of test and calculation of regulated revenues (even if application of test successfully appealed).	As before

There was previously a direct relationship between the outcome of the Regulatory Test and the calculation of regulated assets (and hence revenues) for interconnector investments. Prior to the NDR Code changes, interconnector assets could only be added to the regulatory asset base if they satisfied the Regulatory Test. However it remained unclear whether the amount to be added to the regulatory asset base was the amount specified in the Regulatory Test or the actual cost of the project.

Since the NDR Code changes in March 2002, the Regulatory Test has had no direct impact on the calculation of the regulated asset base. All capital expenditure during the period is entered onto the Regulatory Asset Base at the start of the next period. This is regardless of whether a Regulatory Test has been applied; whether the project passed the Test; and whether the actual expenditure is consistent with the assumptions in the Test.

In addition, the Regulatory Test has no direct impact on the AER's forecast of required capital expenditure during its revenue determination. It is possible that the AER's view of projected capital expenditure requirements would be influenced by the effectiveness with which the TNSP has conducted its capex appraisals. It would however be misleading to consider – or advocate – that the AER is approving a capex program when it makes a revenue determination.

Although the Regulatory Test has no direct impact on the calculation of the regulated asset base, it has been the subject of intensive debate since it was first devised six years ago. This suggests that transmission users and transmission service providers value the opportunity for consultation that the Test provides. It therefore seems valuable to deepen and extend its role as a defined process for consulting on proposed transmission investments.

4.5.4 Conduct of regulation

The 'standard' regulatory model results in powerful incentives on the regulated entity to convince the regulator that its expected expenditure in future will be higher than the regulated entity genuinely expects it to be. By convincing the regulator of this, the regulated entity is able to increase the probability that it will earn higher profits by increasing the gap between its regulatory allowance and its actual expenditure during the regulatory period.

In the 'standard model' this has typically resulted in the regulator setting regulatory allowances for operating and capital expenditure considerably lower than the amounts that the regulated entity had requested in its regulatory application. By contrast in the NEM, regulatory decisions for TNSPs have generally involved small or no reductions to the TNSP proposal.

As described above, the regulatory task in Great Britain is substantially simplified by having one transmission company developing the network as a whole. Australia faces a greater co-ordination problem, since the regulator needs to form a view on efficient investment within an integrated grid, based on proposals by one regionally based TNSP (or two, when it considers Transgrid and EnergyAustralia proposals together).

An alternative would be to conduct the review simultaneously. We note for the example that regulatory reviews for the 12 electricity distribution businesses in the UK have been conducted simultaneously, and combined with the regulatory review for transmission.

5 Assessment of Current Governance Framework

This section assesses the governance framework against the criteria set out in section 3:

- *Dynamic efficiency*: does the framework facilitate least cost investment across the electricity supply chain, and

- *Reasonable certainty:* does the framework provide reasonable certainty for other market participants, and in particular generation investors.

The assessment in this section is based on first principles. We have not attempted quantitative analysis of actual outcomes under the current framework, and their comparison with possible outcomes under an alternative framework.

5.1 Optimal co-ordinated transmission investment across the NEM

It appears unlikely that the current framework is achieving efficient investment, taking account of costs and benefits across the NEM as a whole. Many investments are likely to have impacts outside the region concerned. However, measures to facilitate co-ordination appear much weaker than measures which promote regional decision making.

5.1.1 NEM-wide impact of regional investments

The NEM had its basis in a set of State-based grids, which were sensibly planned on a State by State basis. It then evolved to State-based grids with relatively weak interconnection, where investment in interconnection could be considered separately from investment within the main grid.

The level of interconnection in the NEM has increased significantly over the last five years following the commissioning of QNI, Murraylink, DirectLink, the SNOVIC upgrade and most recently BassLink. The NEM is now deeply interconnected, given the capacity of interconnectors as a proportion of the installed generation and peak demand in exporting and importing regions.

Electrical current follows the path of least resistance, and can not be directly controlled on AC networks. Investment decisions covering the choice of technology, and the design, size and location of equipment in one region of the NEM can affect power flows in other regions. Sometimes this externality effect is not material. However, on the main transmission flow paths – which account for the bulk of the NEM network - the impact can often be significant.

This level of interconnection increases the importance of NEM-wide co-ordination for the efficient development of NEM transmission networks and the energy market. However, as described in Section 4, different arrangements apply for investment decision making for investment to meet reliability within a region, and investment to strengthen interconnection between regions:

- Intra-regional reliability investment is planned on the basis of state-based reliability standards. These standards (other than in Victoria) are focussed on delivering a specified level of network redundancy. TNSPs are clearly accountable to their respective state governments for delivering the specified level of network redundancy, and the regulatory regime is built to accommodate it.

- Inter-regional investment is not planned by any entity. Instead such investment is meant to arise through voluntary processes. Proponents face limited risk in making such investments (since the actual capex will be added to their regulatory asset base). However, the investment is less linked to their statutory core obligations. Such investments may also be unpopular if consumers in one State are considered to be paying for investments that benefit consumers in another State.

This separate treatment of investments which deliver reliability benefits and investments which deliver market benefits is also inconsistent with the physical reality of interconnected networks. Many investments affect both reliability and the capacity of the network to transfer power within and between NEM regions.

An example is a 330kV augmentation in Queensland between Middle Ridge and Greenbank which is currently under construction. This augmentation was justified against Queensland n-1 reliability criteria, but it will significantly affect QNI northward flows.

Another example is a proposed 500 kV augmentation in New South Wales which is proposed on the basis of reliability criteria in New South Wales. This investment will affect the ability of Queensland generators to access demand in New South Wales, through the QNI interconnector. In both cases, an investment which affects inter-regional flows is being appraised on the basis of whether it minimises the costs of meeting reliability standards within one region.

5.1.2 Factors affecting co-ordination of investment planning

As many TNSP investment decisions have NEM-wide rather than regional impacts, we have considered the factors which affect the likely level of co-ordination in investment planning.

Several characteristics seem likely to promote regionalised investment decision making:

- *Ownership:* in all States other than South Australia, the TNSP is owned by the State government. This may result in regionalised decision making, since the companies may be concerned about the incidence of costs and benefits, and the companies may be concerned about impacts on Government-owned generation

- *Planning standards:* in all cases planning standards are determined by State governments or State institutions

- *Conduct of regulation*: the process involves sequential revenue cap decisions for TNSPs (other than in NSW) rather than simultaneous determination. This weakens the ability of the regulator to consider an optimal NEM-wide investment program and reflect it in capital expenditure forecasts

The mechanisms that promote co-ordination are mainly disclosure mechanisms, including:

- the publication of the ANTS by NEMMCO, and Annual Planning Reports by TNSPs

- the publication of an Augmentation Technical Report by the IRPC on request

- the last resort power that the AEMC will direct a relevant party to apply the Regulatory Test (this is yet to written into the Electricity Rules), and

- the provision in the Electricity Rules for governments to agree bi-laterally on the sharing of interconnector costs, and for Settlement Residue Auction proceeds to be allocated to specific TNSPs.

It appears unlikely that the factors promoting co-ordination will be fully effective against such strong "regional" drivers:

- Even if the ANTS is successful in developing accurate and co-ordinated network development plans, co-ordination would only occur if the plan was acted upon. TNSPs have no obligation to act on information contained in the plan, and the linkage to the AER revenue caps is also weak

- Annual planning reports provide an indication of TNSPs' likely network developments. This information may be of some use in identifying investments that merit co-ordination, but again TNSPs have no obligation to act on this information.

- Augmentation Technical Reports are published by the IRPC on request, if TNSPs are unable to resolve differences over investments that are likely to have a material inter-regional impact on the capacity of networks in other parts of the NEM. This mechanism has not been used to date. In addition, the publication of such a report does not constitute an obligation on any party to invest (or to not invest).

- The MCE has decided that the AEMC should have a power to direct a party to undertake the Regulatory Test. However, the application of the Test involves a good deal of discretion. A party directed to undertake the Test against its own volition will seek to ensure that the Test delivers results to its liking. Furthermore, like the ANTS and Augmentation Technical Reports, the outcome of the Test does not bind any party to invest.

- The Electricity Rules provide that State government can agree on how interconnector costs can be shared. Presumably State governments would be free to agree on the sharing of such costs regardless of the provision of the Rules. Furthermore such agreement does not constitute the right to recover such costs from electricity customers through regulated charges – this is determined by the AER, not the governments.

On balance therefore, a 'first principles' analysis suggests that the co-existence of separate regimes for regionalised mandated reliability investment and NEM-wide voluntary interconnection investment, is not likely to result in effectively co-ordinated transmission investment decisions across the NEM. It follows that effectively co-ordinated decisions would be different to those under the existing arrangements. Over time these differences will accumulate, with significant consequences for the efficiency of the transmission sector and the wider electricity market.

Conclusion: the mechanisms to ensure efficient investment across the NEM are weak, and it is unlikely that they result in effective co-ordination.

5.2 Reasonable certainty for market participants

It appears unlikely that the governance framework will deliver reasonable certainty for market participants. We are also aware that major private investors consider that the framework does not deliver reasonable certainty. Factors affecting this include the lack of clarity on the planning standards applying to TNSPs; the cross-ownership of transmission and generation by State Governments; and the weak regulatory constraint.

Transparency is increased when it is clear what standards the TNSP will be governed by as it develops its investment program. Clarity does not require identical standards between TNSPs. However, it does require that the standards themselves are reasonably specific, and are in the public domain. As described in section 4, this is not the case.

Another factor affecting the perception of other market participants is the cross-ownership of generation and transmission by State Governments in Tasmania, Queensland and New South Wales. It is inconceivable that a similar level of cross-ownership by private companies would be tolerated. This cross-ownership may result in transmission investment decisions which favour generation owned by the relevant State government. Regardless of whether it does so or not, it will also result in a perception of a conflict of interest in the TNSP's decision making.

The main countervailing factor is the ability of the regulator to set regulated revenues based on its analysis of an efficient investment program. However, this is unlikely to offset any perception of a possible conflict of interest in TNSP investment decisions:

- The constraint itself is rather weak. The regulated asset base at the start of the next period is based on depreciated actual investment, regardless of whether this exceeds the revenue cap set by the AER. If a TNSP spends above its regulatory allowance it only suffers the loss of the depreciation and return on that overspend for the remaining period of the regulatory control. If TNSP's actual cost of capital is below the allowed rate of return, any detriment arising from overspend will be offset by the benefit to the TNSP of a larger regulatory asset base on which it earns a return for the remaining life of the asset.

- The regulatory resets are conducted sequentially rather than simultaneously, and are based on a State-wide rather than a NEM-wide consideration of the investment program, and

- The conduct of regulation appears to have seen relatively little attempt by the AER to set revenue caps on the basis of a lower investment program than that proposed by the TNSP. This may indicate that TNSPs are generally putting forward efficient investment proposals, or may indicate that the regulator, for whatever reason, faces difficulty in setting a revenue cap on an alternative basis

A possible additional countervailing factor is the Regulatory Test, which sets out obligations on how TNSPs consult on major capital expenditure. This process does appear to increase transparency in decision making, and establishes a defined process for generators and others affected to seek to influence the decision.

However, there is no linkage between the Regulatory Test and incentive regime established by the regulatory framework in the NEM:

- The outcome of the Regulatory Test does not affect whether or not investments by a TNSP are added to the Regulatory Asset Base at the start of the next period. An investment which manifestly failed to pass the Regulatory Test would still be added to the RAB

- The application of the Regulatory Test does not directly affect the regulator's views on the future investment requirements as expressed in the capex allowances in revenue control decisions. In most cases, a Regulatory Test will not yet have been conducted for such investments. Even if it has, the nature and cost of the project may well have changed by the time it is implemented

A separate issue is whether the Regulatory Test could be used to ensure desirable investments proceed, where these are not being taken forward by the TNSP. The AEMC is developing a power to direct that a project be taken through the Regulatory Test. Currently there is no ability to direct a TNSP to proceed with an investment. The merits of changes to these arrangements is considered in section 6.

Conclusion: the significant cross-ownership of transmission and generation creates the perception by private investors of a conflict of interest. Regulatory constraints, either through the imposition of a revenue cap or the application of the Regulatory Test, are not effective in reducing that perception.

6 Possible improvements

6.1 Introduction

As earlier sections have shown, there has been substantial progress in the establishment of a single market, NEM-wide institutions, and a stronger transmission grid. However, the NEM continues with a complex and inconsistent governance framework for transmission.

Although the jurisdictions have all transferred responsibility for regulation of transmission to the AER, this is a long way from establishing a consistent NEM-wide governance framework:

- the *obligations* of the TNSPs are defined by planning standards set at State level. The form and content of the planning standards differ between States

- the *form* of the TNSP differs between States. Five TNSPs are for-profit companies, and subject to a CPI-X constraint. One TNSP is a not-for-profit authority that procures but does not own transmission capacity. This body is subject to much less regulatory control

- *planning and investment decision making* is entirely undertaken at a State level, with weak arrangements for national co-ordination; and

- the *form and conduct* of regulation cannot fully offset the regionalised approach to transmission planning. All jurisdictions have transferred responsibility for transmission regulation to the AER. However, regulation is conducted sequentially for TNSPs in each region. To date, the regulatory constraint appears fairly weak – the regulator has been reluctant to remove proposed investments from the forward program.

This section considers options for these different elements of the governance framework. We have considered three possible combinations of approach:

- *Modified status quo:* continue a regionalised approach to planning and regulation, but modify current practices to seek more NEM-wide outcomes.

- *Stronger national regulation:* retain regionalised decision making, but combine this with stronger national planning and simultaneous conduct of regulatory determinations. This approach leaves investment decisions to the existing TNSPs, but subjects them to stronger regulatory oversight, informed by stronger national planning. While this approach would not involve a transfer of decision-making powers to a new entity, it could nevertheless be a significant departure from the existing arrangements depending on the authority of the advice provided by the national planning body., and

- *National procurement of transmission capacity:* establish a national entity which determines investment requirements, and procures transmission capacity, on a NEM-wide basis. This represents a significant departure from the existing arrangements and would involve the transfer of decision-making powers and accountabilities to a new entity.

We have also considered a fourth option, which entails involvement of generators in investment decision making. This is considered as a separate option, since it could be introduced under any of the options considered above.

This section also assesses how these options perform against our assessment criteria, and in particular how far they address material problems under current arrangements. Our assessment of the current governance framework identified two principal problems:

- uncertainty arising from the joint ownership of transmission and generation, and the lack of clarity on obligations for TNSPs and on regulation of investment decisions, and

- possible loss of dynamic efficiency through inadequate transmission investment co-ordination.

Divestment of generation and/or transmission capacity by State Governments could reduce or remove the perceived uncertainty from joint ownership. We have not considered this option, which lies within the policy remit of the current owners.

If there continues to be cross-ownership of generation and transmission, transparency is increased by a credible constraint on the owners. Stronger mechanisms to co-ordinate transmission investment will reduce the extent to which investment decisions are perceived to be influenced by their interests, including their interests in generation. As a result, approaches to the problem of co-ordination of transmission investment generally also assist the problem of a perceived conflict of interest from joint ownership of generation and transmission.

6.2 Modified Status Quo

It would be possible to largely continue the current responsibilities for investment decision making, and for the form and conduct of regulation, but seek modifications to current arrangements that make this model more effective. The modifications we have considered are:

- Greater consistency in planning standards

- Establishment of a national planner, whose role is to disseminate information, and

- Modification to the Regulatory Test arrangements

6.2.1 Greater consistency in planning standards

The Electricity Rules provides little more than a framework for the specification of reliability standards. The dominant role in the specification of reliability standards is played by State governments. In three States, the specification of these standards has effectively been delegated to the State-based TNSPs.

The transparency of planning standards would be improved by defining the reliability of supply at specific bulk supply points. However, the specification of the standards in this way does not easily translate to a design of the transmission network needed to achieve such reliability. As a result, this provide greater clarity on the level of reliability that the transmission system would be designed to deliver at those supply points, but less clarity on the supporting investments required in the transmission network.

Another approach would be to prescribe the calculations that TNSPs would be required to undertake in the application of planning standards. This could take the form of specific guidelines for the assumptions on key variables such as probability-of-exceedance demand forecasts for both pre and post contingency conditions, the value of customer reliability, the specification of critical contingencies, the treatment of generation availability and how future power flows or power system security conditions are modelled.

The impact of this approach on clarity may be limited. Many of the critical variables in the planning process relate to expectations of future demand and supply and their interaction. These variables are inevitably uncertain and require the exercise of judgement. Even if the suite of planning standards were common in all NEM regions, their application by different planning engineers, may nevertheless result in different investment decisions.

Attempting to reduce the planning of such networks to a set of precisely defined rules will undermine the ability of transmission planners to exercise their professional judgement on the most efficient network development.

Our conclusion is that a relatively modest prescription of the form of planning standards to apply at bulk supply points would provide a modest, but desirable improvement in transparency for market participants.

6.2.2 Strengthened information dissemination

The quality of investment co-ordination could be improved through the provision of more comprehensive data on power flows on national transmission flow paths, and higher quality analysis of possible augmentation options. This could be achieved by strengthening the information provision requirements to NEMMCO as part of the compilation of the ANTS.

NEMMCO's role in the production of the ANTS could be extended so that the ANTS is required to provide comprehensive views on the most efficient investments on national transmission flow paths. This would require greater cooperation with TNSPs on planned reliability augmentations that could affect power flows on national transmission flow paths. Greater interaction would also be required in the detail specification of investment options.

6.2.3 Modification to the Regulatory Test arrangements

During the course of this assignment, a number of people have suggested to us possible modifications to the Regulatory Test designed to deliver decision making on new transmission investments with a stronger NEM-wide focus. These are discussed below. We also recognise that the role of the Regulatory Test is being reviewed by the AEMC.

We have considered three possible changes to the Regulatory Test:

- The market benefits limb of the Test is conducted by a party other than the TNSP, possibly combined with a power to direct that an augmentation proceed if it passes the Test;

- All Regulatory Tests are conducted by a third party; and

- The Test is applied to a long term investment program rather than individual projects.

The first of these options appears to reflect a concern that there are potentially economic investments which are not proceeding, and that one cause of this may be bias on the part of TNSPs in either identification of such projects, or the conduct of appraisal. If this was the case, then assigning that responsibility to a third party – such as a National Planner – might overcome any biases of that kind.

An approach of this kind would be feasible if there were a clear distinction between investments which promote reliability, and investments which provide market benefits. If investments to meet these two objectives were completely distinct, then there would be no difficulty in assigning them to different agencies.

In practice however, many transmission augmentations affect both reliability and the level of existing and future transmission losses and constraints. There is a clear discussion of this point in CRA's report, and we have not repeated that analysis here. The interaction between reliability investments and interconnection is also illustrated by the change in the feasibility of interconnects – such as an upgrade of QNI – from year-to-year. The main factor causing that change is the level of investment for reliability purposes in each region, and the impact that has on the economic case for interconnection.

As this illustrates, there is no clear basis for separately optimising between transmission investments for reliability benefits and transmission investments for market benefits. It is unlikely that an attempt to separate responsibility for those investment decisions, and assign responsibility to different entities, would increase either efficiency or transparency.

As different types of investment cannot be separately considered in this way, a second option would be for the Regulatory Test to be conducted by a third party for all investments.

If the third party was simply responsible for the conduct of the Test, then it might remain unclear how the outcome of the Test was related to the actual investment decisions of the TNSP. Alternatively, if the third party had an ability to direct that an investment proceed, following its conduct of the Test, then the third party would effectively become the TNSP.

This would be similar to the model adopted in Victoria, where decisions on transmission augmentations are taken by a not-for-profit, statutory authority. Imposing this model on all jurisdictions would entail a radical shift from current arrangements, and cannot be considered simply a modification of the status quo. If this change in corporate structure was combined with a continued regionalised approach to planning, it is likely that it would do little to reduce any perception of conflict of interest. We consider below whether it could be combined with a NEM-wide approach to investment decision making.

A third option would be to move away from a project-by-project consideration under the Regulatory Test to consideration of longer term integrated investment programs. Transmission investment decisions are interconnected, and a project by project optimisation is unlikely to yield an optimal investment program. If a process is to be established for the conduct of investment appraisal, it therefore seems preferable that this should apply to aggregated investment programs rather than individual projects. Again, this point is well discussed in CRA's report.

The main difficulty with a proposal of this kind is that the conduct and outcome of the Regulatory Test remains unrelated to the investment incentives for TNSPs:

- All investments by a TNSP are added to the Regulatory Asset Base at the start of the next period, regardless of whether they were subject to the Regulatory Test, the outcome of the Test, or whether the investment matched that which was the subject of the Test

- There is currently no linkage between the conduct and outcome of the Regulatory Test and the capital expenditure for the next regulatory period, and

- More generally, the regulatory framework for five of the six TNSPs does not consist of a project by project approval by the regulator, but rather consists of a revenue cap combined with obligations to meet defined standards.

As a result, a change of this nature may have little impact unless there is a specific linkage to the regulatory incentives. We consider in the next section whether such a linkage could be achieved through introduction of a stronger regulatory constraint.

6.3 Stronger National Regulation

For five of the six TNSPs, the regulatory framework is a five-yearly reset, with incentives to pursue efficiency within the period, since TNSPs benefit if actual capital or operating expenditure is below the levels reflected in the revenue cap.[5] However, that framework has become increasingly confused by the focus on rules relating to the process for 'within-period' investment decisions. This option would consist of a more thorough application of the original incentive-based model.

This option would also entail the establishment of a National Planner. However, rather than simply playing a role in dissemination of information, the National Planner could play a stronger role. This might include:

- The provision of consistent scenarios to be used for appraisal of investment proposals across the NEM, and

- The provision of technical advice to the AER on efficient NEM-wide transmission investment, as an input to its revenue cap determinations.

[5] This also applies to SP AusNet (excluding augmentation capex), but SP AusNet is not a TNSP.

Interconnection in the NEM is now relatively strong. The case for investment within one region in the NEM is therefore strongly affected by proposed investments in other regions. However, the AER faces difficulty in imposing a revenue cap based on its views of efficient investment across the NEM, since revenue determinations are undertaken sequentially, on a region by region basis.

This model would therefore be assisted by a move to simultaneous conduct of regulatory reviews for all TNSPs. It is likely that this would require additional work, and perhaps longer time lines than those which have been proposed by the AEMC for the current regulatory reviews. However, there are substantial economies of scale in the conduct of these reviews.

This approach might increase the likelihood of a revenue cap which rejected or modified TNSP investment proposals, as the AER forms a stronger view on efficient NEM-wide transmission investment. Alternatively, it might lead to greater co-ordination between TNSPs to minimise NEM-wide costs, given the increased exposure to regulatory risk.

6.4 National Procurement of Transmission Capacity

The models above consider how investment decision making continues to be taken on a regional basis, with pressures to optimise NEM-wide transmission investment through information disclosure, defined consultation processes, and imposition of a regulatory constraint based on NEM-wide analysis.

A more direct approach would be to establish a single entity to take NEM-wide decisions on new transmission investment. This approach would also reduce the strong link between State Government ownership of transmission and generation companies, since State Governments could be expected to have shares or voting rights in the new entity, rather than 100% ownership and full control of board appointments.

6.4.1 Role and functions

With this model, the role of the national procurer will be to both plan and develop transmission augmentations. Such augmentation would not distinguish between projects that may currently be considered to be either “reliability” or “market benefits”.

The procurer will be primarily a planner and contractor. It would plan augmentations necessary to ensure that reliability standards are met, and also where the benefits of such investment would exceed their cost. It would let contracts that may typically be Build-Own-Operate- contracts for the development of specific projects. The contracts could be subject to competitive tender or negotiated arrangements with the incumbent TNSP. The procurer would determine the use of system charges necessary to recover the costs of the investments it plans and executes.

The procurer would not operate the network and would not be responsible for the provision of ancillary services. The procurer is also not expected to be involved in the development of bulk supply point connections, but can be expected to be involved in major generation connection. Clearly in planning and developing augmentations there will need to be significant operational level interaction between the national procurer and the transmission asset owners.

6.4.2 Corporate form

If a national body was created, there would be two options for its corporate form. It could be a for-profit company, which owned and operated the assets, as is the case for five out of six of the TNSPs in the NEM. Alternatively, it could be an entity which procured transmission, but which did not own and operate assets. The factors affecting choice of corporate structure include:

- *Ease of transition:* a model where the national entity only procured transmission services, rather than owned and operated assets, is likely to be less disruptive. Existing TNSPs could continue to own and operate assets as at present. In the case of VENCorp, existing contractual arrangements could be novated to the new transmission entity, or could continue to be managed by VENCorp

- *Transparency:* a model where the national entity was an asset owner would create a dominant single company. This would be a very large business, with significant assets and large number of employees. It might have a strong interest in promoting transmission investments over other solutions. This might create a significant challenge in imposing effective regulation. A model where the national entity procured services rather than owning assets would not require the creation of a single large company, and might be more consistent with transparent regulation

- *Consistency with existing approaches:* five out of six TNSPs are for-profit entities which own and operate assets. Only one procures transmission services without owning assets. An approach which established a national transmission company which was also an asset owner might be more compatible with the existing regulatory framework for five out of the six TNSPs. On the other hand, it might also be more disruptive, since it would require changes to current ownership arrangements.

We consider that the balance of argument would be for creation of an entity which procured transmission services, rather than owning and operating transmission assets.

6.4.3 Interaction with regulation

The introduction of an entity that procured transmission capacity would substantially reduce the regulatory task. Capital expenditure would be determined by:

- Investment decisions taken by the not-for-profit entity. Provided this was combined with appropriate governance arrangements for such an entity, there would be no benefit from further regulatory scrutiny of those investment decisions, and

- Competitive tender, and/or sole source negotiations, to determine the least cost means of building and operating the additional transmission capacity.

Under this model, the role of the AER would therefore be reduced. This would be consistent with the lower role for regulatory scrutiny in Victoria, where additional capacity is procured by VENCorp, rather than owned by VENCorp.

Although the regulatory task with respect to future capital expenditure is likely to be reduced, there would however be a regulatory task associated with review of the operating costs of the procurement body; and a legacy task for review of the operating costs and the renewal costs for the existing transmission network. For example, SP-Ausnet spends around $400M over five years on asset replacement and capitalised maintenance, which is subject to regulatory review.

Under this model the national transmission entity would also be de facto undertaking national transmission planning, since it would be determining which investments should proceed. It would be possible for this entity to combine the planning function and the procurement function. Alternatively, a National Transmission Planner could be established, which both disseminated information for market participants and acted as an adviser to the national transmission entity.

6.5 Institutional arrangements

The discussion above has summarised the key features of the three options. In this section we consider the possible institutional design of arrangements for each option. As these options are at an early stage, our approach is often to set out the decisions that would need to be made, rather than a fully developed approach. However, we have been more definitive on aspects of institutional design where the correct approach seems to be self-evident, or a single approach appears likely to receive general support.

6.5.1 Modified status quo

The modified status quo would essentially be an extension and deepening of existing arrangements. We assume NEMMCO would continue to have responsibility for preparing the national planning document (as it does for the ANTS), but that this document would be strengthened.

The steps required would include:

- The scope of the information to be disseminated through the National Transmission Plan. This might be limited to national transmission flow paths, or could be extended to lower levels of the transmission system

- The obligations for TNSPs to provide information to NEMMCO to support that planning function, and the mechanism for ensuring those obligations are met

- A possible formalisation of consultation or other mechanisms for industry input into the preparation of the National Plan.

Under this option, the plan would be more substantial than the current ANTS. This would inevitably raise issues about the interaction of the plan with TNSP decision making. For example, there might be a need to monitor TNPS progress against the plan, and to monitor and account for any deviation from the plan.

There would also be a need to determine the relationship between the National Plan and analytic work undertaken by the AER when conducting revenue resets. In other words, there would be a need to avoid having three views on efficiency investment: those set out in the National Plan, those reflected in TNSP planning and investment decisions, and those reflected in AER decisions on the revenue cap.

As this indicates, a substantial strengthening of National Planning without directly linking it to either transmission investment decisions or transmission regulation is likely to prove problematic.

6.5.2 Stronger National Regulation

This option would entail the establishment of a strengthened national transmission planning function. The function would have a strong link to regulatory decisions and so a major impact on revenues for TNSPs.

A first issue would be the appropriate location of this function. Possible options would be for the function to be located within NEMMCO, within the AER, or as a new special purpose entity. A possible subset of these options would be for a new division to be created, within either NEMMCO or the AER, which drew on corporate overheads but which had separate governance arrangements, including budgeting, review and approval of the planning work, and consultation with market participants.

For either a special purpose entity, or a division of an existing organisation, there would be issues around the resources for the national planner, and mechanisms for ensuring resourcing was adequate but not excessive; the source of funds; and, if a new body was created, the ownership, corporate form, arrangements for board appointment and the shareholders agreement or other mechanism for setting out how decisions would be made.

The scope of this national planning function would need to be determined. Issues would include:

- The scope of the planning undertaken by the National Planner, and the extent to which it covered national flow paths, other intra-regional augmentations; non-augmentation expenditure and connections

- The mechanism, if any, for review of the National Planner's plans

- The relationship between jurisdictional planning standards and the plans

- The nature of any obligations on TNSPs to provide defined information, in an accurate and timely manner, and

- The nature of any obligations on the National Planner on the way in which it implemented its task

A key issue would also be the inter-relationship between the National Plan, the planning and investment decisions of the TNSPs, and the revenue resets by the AER. The assumption behind this model is that the National Plan would enable a more informed determination of TNSP revenue requirements. This would be supported by the AER undertaking simultaneous revenue determinations for each TNSP, based on the National Planner's advice on efficient capital expenditures.

The AER establishes maximum revenues, based on its assessment of the revenues required to recover efficient expenditure and a reasonable return on the regulatory asset base. However, it does not determine actual expenditure, which is the responsibility of the TNSP.

Consideration would need to be given to the interaction between the National Planner's views on efficient expenditure – which form the basis of TNSP revenues during the regulatory control period – and the actual expenditure program by the TNSP. Similarly, if the National Planner altered its plans each year, and this results in a differing forecast of required investment, the implications of this for the design of the regulatory arrangement would need to be considered.

An approach consistent with the regulatory framework might be for revenue caps to be determined every five years, based on the National Planner's advice on efficient capital expenditure, but with no intention that this determined an actual investment program. As the required level of investment altered over time, and was reflected in the National Plan, the financial impact would be borne by the TNSP, until a future reset.

While the principle of drawing on advice from the National Planner is clear, detailed implementation would need to consider the interaction of this approach with the AEMC's determination of 16 November 2006 on Economic Regulation of Transmission Services, and the corresponding final Rule determination. We have not undertaken that detailed review.

Given the direct impact on their revenues, it is also likely that TNSPs could seek to influence or dispute the conclusions of the National Planner. A robust process would be required for preparation of plans, consultation, and – if appropriate – resolution of disagreements and disputes.

Finally, consideration would be needed on how best to phase in this arrangement. One possible approach would be for the AER to make successive shorter determinations until a simultaneous revenue reset could be undertaken for all TNSPs.

6.5.3 National Procurement of Transmission

A move to a national entity which planned and procured transmission services is the option that would entail the most significant change from current arrangements.

The scope of the national procurement function would require definition. One option would be that this entity procured all augmentation. Another option would be that it procured transmission augmentations above a certain size. This would require clarity on how transmission investments are packaged for consideration of size. A further option would be that it procured particular types of assets. For example, existing TNSPs might continue to develop connections and feeder substations in cooperation with the distribution network service providers.

A key requirement for this option would be the support of the Governments which currently own TNSPs. A situation where a national entity planned and procured capacity, but a State-based entity could also develop new capacity – and recover the costs from users - would lead to confusion.

The mechanism for procurement would also need specification. Options would include:

- *Competitive tender:* it is possible that some discrete augmentations could be tendered on a build, own and operate basis, with the tender used to determine efficient lifetime costs

- *Negotiation:* some investments may be heavily inter-related with existing assets, and it may not be feasible to tender them. If so, a basis would be required for determining efficient costs.

Regardless of whether a price is determined by tender or negotiation, the result would be a contract to provide defined transmission services. The specification of the contractual relationship between the National Transmission Planner and procurer and the provider of transmission would be an important component of this arrangement.

This option may result in a significant change in the value of existing transmission businesses. Rather than having an effective monopoly over investment and operations within a defined region, these businesses might now have reduced ability to determine future investment, and a new exposure to competitive tender. If this option gained support, there may therefore need to be a significant negotiation with existing owners, given the major change to their operating environment and financial position[6].

The interaction with regulation would also require clarification. Our assumption is that there is no regulation for new transmission procured by the national transmission planner – and that the planning and procurement process is deemed to have determined efficient costs. However, there would be a significant remaining regulatory task related to revenues allowed by the regulator for the 'legacy' transmission assets.

Under this option, the national transmission planner and procurer would become the key entity determining new investment. The governance arrangements for the new entity would be of great importance. This would include:

- The legal form of the national transmission planner and procurer. We anticipate this is likely to be a statutory authority or a not-for-profit company, rather than a for-profit company

[6] This may not apply to SP Ausnet, which already operates under a regulatory framework similar to this.

- The ownership of the new entity, the process for board appointment, and the rules governing decision making by the board.

- The rights and responsibilities of the new entity and the nature of any rights of appeal against its decisions

Given the scale of the change required, transition arrangements would also be of great importance.

Finally, we note this option would essentially move away from a traditional CPI-X form of regulation, to one which relies on the governance of a procurement entity. This is likely to require changes to the Rules relating to the economic regulation of transmission.

6.6 Involvement of transmission users in investment decisions

In the design of the NEM's regulatory arrangements effort has been made to encourage the participation of transmission users in transmission investment decisions. For example the publication of the Annual Planning Reports, ANTS, and Regulatory Test all place information in the public domain so that transmission users are able to comment on investment decisions by TNSPs.

There are many cases of effective consultation between TNSPs and their customers, for example in the determination of connection costs. State-based planning standards also often provide for negotiation between TNSPs and other parties – typically distributors – to decide where reliability requirements higher or lower than the default, should apply. Such negotiations do occur and result in different investment outcomes.

The Electricity Rules also provides for generators who wish to obtain firmer transmission access, to negotiate with TNSPs to secure such access.

It would also be possible to involve transmission users more directly and more substantially in decisions on major investments in the transmission network. Attachment 1, prepared by Stephen Littlechild, provides a number of examples of customer involvement in investment decisions in electricity transmission and in a range of other sectors, and sets out ways in which transmission users in Australia could be involved in investment decisions.

Following practice in Argentina, users rather than transmission companies could propose and make investment decisions. Voting rules would be specified for users, and might also specify the sharing of charges. This approach could be accompanied by an obligation to tender proposed expansions above a specified size.

Less radically, an existing planning entity might be responsible for developing a proposed transmission program. Alternatively a program could be drawn up by an organisation of customers (including generation, distribution and retail companies as well as large users). The program would be subject to review by a Transmission Committee comprising representatives of customers (including generators and end-users), other interested parties and transmission companies. Approval by the Transmission Committee would be required before a transmission programme could go ahead. This would have some similarity to the provisions in Chile. Encouraging interested parties to agree in this way might be particularly appropriate where the concern is primarily associated with coordination and timing.

It would be possible to encourage this approach within the present federal and state regulatory frameworks. For example, regulatory obligations might include 'promoting negotiated settlements or other arrangements agreed between licensees and consumers'.

Arrangements of this kind would require consideration of:

- Whether there should be weighted voting among customers, and if so whether votes should be weighted by transmission usage or transmission charges paid.

- Who would represent end-user customers, and

- Mechanisms for customers to obtain relevant information from the companies, perhaps via the regulator. Customer groups could commission expert advice as required. In some jurisdictions there is provision for the settlements to cover the legitimate costs of such intervenors.

The involvement of transmission users in investment decisions in this way represents a significant departure from the existing institutional design. A change in this way would not be compatible with Option 1 (modified status quo). However, it would be possible to implement some form of transmission user investment decision making into either Option 2 (national planner) or Option 3 (national procurer). Working out all the details of an approach for fully involving customers in the choice of transmission investments in Australia is beyond the scope of this present paper. However, experience elsewhere suggests that a suitable approach can be found to provide results that are acceptable to all the parties and preferable to conventional regulation.

7 Conclusions

The NEM is a single wholesale market. The wholesale market is broken down into six regions. The transmission grid provides relatively strong interconnection between those regions. The current governance framework for transmission relies on investment decisions by six regional TNSPs to deliver optimal investment across that network.

We have considered three options to amend this framework to ensure optimal investment across an integrated grid.

- *Modified Status Quo:* greater clarity on planning standards, the establishment of a National Planner to disseminate information, and possibly further codification of decision making processes, through the Regulatory Test.

- *Stronger National Regulation:* the establishment of regulatory incentives, through the application of simultaneous five yearly revenue caps for all TNSPs. This would be supported by a National Planner to provide strong and well-informed independent advice on efficient investment across the NEM

- *National Procurement of Transmission:* establish a NEM-wide entity responsible for making decisions on transmission augmentations. As a result, NEM-wide costs and benefits could be internalised within the company. Our preferred structure for this entity would be a not-for-profit entity with the corporate governance – rather than external regulation – as the principal driver for efficient decision making.

Table 5 summarises our assessment of these options against the assessment criteria. This is more fully described in the subsequent text.

Table 5: Assessment of options

	Efficient investment	**Transparency and reasonable certainty**
Modified Status Quo	The National Planner would improve the information base for TNSPs when they make investment decisions, and market participants when they are consulted. The impact may be minor, as there would be no direct linkage between planning outputs and regulatory incentives.	More specific planning standards could provide a modest increase in transparency. Market concerns from joint ownership of generation and transmission would not be addressed.
Stronger National Regulation	Regulatory decisions would be improved by simultaneous reset.	No change in joint ownership of generation and transmission. However,

	A stronger link would be established between national planning and regulatory decisions. The impact on incentives for efficient NEM-wide investment depends on: • Credibility of a strong regulatory constraint • TNSP governance	transmission investment decisions may be subject to strong regulatory constraint
National Procurement of Transmission	Strong link between National Planning and investment decisions. Financial incentives for investment planning may be reduced, but financial incentives for efficient supply and operations of transmission capacity maintained May facilitate governance arrangements which involve other market participants and major consumers in transmission investment decisions	Would substantially reduce the link between generation ownership and decisions on transmission investment Corporate structure would need to ensure appropriate balance between centralised and delegated decision making Raises the risk of lack of transparency in decision making by a single national body
Involvement of transmission users in investment decisions	Has the potential to increase efficiency. However, would require considerable work on detailed design	Has the potential to increase transparency, but dependent on actual experience

7.1 Modified Status Quo

The status quo mainly relies on information disclosure and consultation mechanisms to ensure a co-ordinated approach to transmission investment across the NEM. This could be strengthened through a modest increase in prescription on the planning standards, and through establishment of a National Planner to disseminate information.

These measures would not directly address investment incentives which – for five out of six TNSPs – depend heavily on the regime for economic regulation. They would also not affect the joint ownership of transmission and generation, and the perception that this could influence transmission investment decisions.

Establishment of a National Planner may assist an informed discussion of future investment, and may assist market participants in advocating or opposing particular investments. However, it would be important under this model to avoid split accountability. The TNSP would remain responsible for meeting planning standards, and for its investment decisions. The AER would remain responsible for setting revenue caps based on a view, among other things, of efficient levels of capital expenditure over the period. As a result, the benefits from establishing a National Planner would be real but limited.

Conclusion: this option leaves the existing structure largely in place, and would deliver modest benefits. The introduction of clearer planning standards would assist transparency at customer level, but have limited impact on transparency over investments in the backbone of the transmission network.

7.2 National Regulation

The status quo relies on incentives to minimise the costs of meeting defined obligations, within a revenue cap established by the AER. This option would reinforce this regulatory model, through introducing a National Planner to advise on NEM-wide transmission investment, and a simultaneous determination of TNSP revenues by the AER.

The main attraction of this option is that it is consistent with the model for economic regulation for five out of the six TNSPs. It would have less impact in Victoria, given the lower role of regulatory review in that State.

There may be concerns about the credibility of the constraint, and the likely TNSP response:

- This model relies on the ability of the AER to impose a revenue cap, based on its assessment of efficient NEM-wide investment. This may entail rejection of capital expenditure proposals made by the TNSP. This would be consistent with the approach taken in other OECD countries. However, it is unclear whether it would be easy to implement when regulating a Government-owned TNSP.

- This model also assumes that TNSPs are profit-driven, and seek to minimise the cost of meeting their regulatory obligations within a cap imposed by the regulator. This assumption is required regardless of the level of the revenue cap. However, TNSPs may consider that they have obligations to respond to government objectives, rather than simply seeking to maximise profits. If so, the result might simply be to alter the profitability of TNSPs, but not to strongly affect investment decisions. In other words, a lower cap might simply result in more expenditure above the cap.

The direction of this model also appears inconsistent with the policy settings to date by the AEMC. A number of measures appear focused on reducing regulatory risk, including continuation of the policy that all capital expenditure enters the regulatory asset base at the start of the next period, and moves to alter the strength of regulatory review of capital expenditure proposals. The most appropriate way of influencing those decisions would be through submission to the AEMC's review.

This model would not remove or reduce the joint ownership of generation and transmission.

Conclusion: this option should strengthen the effectiveness of economic regulation. Simultaneous conduct of revenue determinations should assist regulatory review, and this should be supported by stronger national planning. The impact on TNSP investment behaviour, and on transparency for other market participants, is uncertain.

7.3 National Procurement of Transmission

The third option would be to ensure integrated decision making by creating an integrated decision maker. The national body would plan and procure transmission capacity, but would not own or operate the assets.

This model would entail a shift away from the regulatory framework applying to five of the six TNSPs. Financial drivers for efficient investment planning would be removed, since the national body would no longer be seeking to minimise the costs of meeting planning standards within a revenue cap.

Efficient investment decision making would depend on the governance arrangements for the institution, rather than its financial incentives. This option would require representation of different parties on the board of the national body which was procuring transmission capacity, and rules for how decisions would be taken on that board. This should reduce the perception of a conflict of interest between ownership of generation and transmission by State Governments. It would also facilitate the introduction of new governance arrangements, where other market participants are represented on the board.

A national procurement model would run a risk of over-centralisation. It would be necessary to develop a structure with a number of local offices, and an appropriate balance between centralised and delegated decision making.

Efficient supply and operation of transmission capacity would be achieved through a combination of competitive tender and negotiation.

Conclusion: this option directly addresses the problem of co-ordinated decision making and is likely to be the most effective at meeting ERIG's objective of achieving a truly national approach to the future direction of the grid. It would reduce the problems arising from joint ownership of transmission and generation. It would however be more disruptive and challenging to implement.

7.4 Involvement of transmission users in investment decisions

A further option would be to involve transmission users in preparing and/or approving transmission investments.

An approach of this kind has the potential to improve investment efficiency. It would reduce any concerns arising from joint ownership of generation and transmission. It might in time provide greater transparency and certainty on transmission investment. However, this would be dependent on detailed design of the scheme, and on experience under the scheme.

It would be preferable to develop this in an incremental manner, and to combine this option with other steps outlined above:

- *National planner:* if a national planner was created, transmission users could be represented on the board of the new institution, and could play a role in approving its planning work

- *National regulation*: the regulator could be given an objective to promote negotiated agreements between transmission companies and end users. This would appear fully consistent with the approach being developed by the AEMC in its review of transmission revenue and pricing Rules

- *National procurement:* if a single entity was created to procure transmission capacity across the NEM, the governance arrangements could be designed to ensure representation of transmission users, and to define the basis on which they would be involved in approving the proposed investment program

It follows that the optimum mechanism for involvement of transmission users needs to be developed further in light of ERIG's overall recommendations.

Conclusion: mechanisms for stronger involvement of transmission users in investment decisions should be developed, in a manner that is consistent with ERIG's overall recommendations.

7.5 Overall conclusions

The current highly regionalised framework for transmission appears inconsistent with the evolution of market rules, operations, dispatch and the transmission grid itself. It is unlikely to result in efficient investment. It will be challenging to demonstrate this in a quantitative manner.

Modification of the status quo would provide some benefit, but this would be limited to information dissemination. TNSPs and the regulator already require views on efficient investment, and a third view – if it takes on any status beyond simple provision of information – runs the risk of confusion.

Our preference between the other two options would be to establish a single entity to take decisions on transmission investment across the NEM (a national procurer). This reduces the co-ordination problem, and also reduces the problem arising from cross ownership of generation and transmission. However, we recognise this would be a major reform, with significant transaction costs and potential disruption to the market.

Stronger national regulation (a national planner) could, in theory, also provide significant benefits. However, we have doubts whether this model is or will be fully applicable:

- Historically, the regulator appears to have faced difficulty in setting revenue caps based on an alternative view of efficient investment. In addition, the Rules developed by the AEMC have to some extent focused on reducing regulatory risk

- This framework relies on profit-driven TNSPs, but it is unclear that financial outcomes are indeed the key driver, and

- Despite having incentive-based regulation based on a revenue cap for five out of six TNSPs, there has been a constant focus on review of specific investments, which appears inconsistent with this model.

There is therefore a risk that this model could simply lead to an additional view on efficient transmission investment, run the risk of conflict between the National planner and the TNSPs, but be less effective at ensuring efficient investment decisions than the third option

Conclusion: a governance framework which moves towards a single NEM-wide decision maker on transmission investment, with end-user representation, should be considered. The final decision should be based on the response of market participants to ERIG's recommendations.

Scope for customer involvement in transmission planning decisions in Australia

Stephen C Littlechild[7]
21 October 2006

Outline

1. Introduction
2. Transmission concerns in Australia
3. Potential for customer involvement to address these problems
4. Evidence from UK: Lighthouses and Airports
5. Evidence from Argentina: Public Contest method in electricity transmission
6. Evidence from Chile: transmission expansion
7. The concept and practice of negotiated settlements
8. Evidence from US: negotiated settlements for gas pipelines at FERC
9. Further evidence from US: negotiated settlements (stipulations) in Florida
10. Evidence from Canada: negotiated settlements for oil and gas pipelines
11. Summary and implications of international experience
12. Adapting these ideas for electricity transmission in Australia.

1. Introduction

The Energy Reform and Implementation Group (ERIG) has raised the question whether electricity transmission arrangements in Australia are as efficient and satisfactory as they might be. Firecone has been asked to report on National Planning Arrangements and Governance Options.

In a number of other countries and other sectors, governance options include regulatory arrangements that significantly involve utility customers in regulatory decisions. Firecone has asked me to describe such arrangements and to indicate how these might be applied in transmission planning decisions in Australia.

The next two sections briefly note some concerns about present transmission arrangements in Australia and suggest how significant involvement of customers could help to address these concerns. The main body of this paper describes arrangements that apply in a variety of other sectors and countries. The final two sections summarise this experience and suggest some possible ways of applying these ideas in the governance of the transmission sector in Australia.

2. Transmission concerns in Australia

A variety of different transmission arrangements exist in Australia, and a variety of different views has been expressed about these arrangements. Perhaps transmission entities seem relatively satisfied with the present situation, but customers of the transmission system (including generators and major users) seem less convinced.

I understand that among the main concerns cited are the following:

[7] Emeritus Professor, University of Birmingham, and Senior Research Associate, Judge Business School, University of Cambridge. Former UK Director General of Electricity Supply, 1989-98.

- co-ordination problems, including between transmission organizations in different states, not fully met by present co-ordination mechanisms (ANTS, IRPC, APRs);
- transmission investments crowding-out generation investments in certain states (e.g. NSW, QLD and TAS) particularly by virtue of integration between generation and transmission organizations in these states;
- greater spending by government-owned TNSPs in the absence of regulatory constraint, as evidenced by the relatively high level of capex and opex by government-owned TNSPs; and
- at some times, concerns by large users about potentially inadequate transmission interconnections.

3. Potential for customer involvement to address these problems

Many of these concerns seem to reflect a perception that transmission investment decisions are predominantly determined by transmission entities and/or by planning organisations that may have limited information and undue concern for their own interests, and insufficient awareness of or concern for the interests of the customers of the transmission systems.

Customers of a transmission system potentially include generating stations that need to convey power to markets; suppliers and large and small customers that need to procure power from generation sources; and distribution companies whose investment programmes may be impacted by transmission. They may also include interconnectors, generating stations, transmission companies and all the above types of customers in one state whose interests may be affected by a particular transmission investment (or lack of it) in another state. Precisely how Australian transmission customers are best defined for operational purposes is a matter for further consideration.

In general terms, the proposal in this paper is that more effective involvement of customers in transmission investment decisions could help to address the concerns mentioned above. Specifically,

- customers adversely affected by a proposed transmission investment (or lack of it) would have an interest in bringing this to the attention of the proponents and suggesting an alternative approach;
- generator customers that would be adversely affected by a proposed transmission investment could argue against it;
- customers of all kinds that considered that unnecessary (or unnecessarily expensive) transmission investments were being proposed would be able to oppose them; and
- customers concerned about inadequate investment could take steps to propose such investment.

The nature of such customer involvement is critical. To varying extents there is at present some opportunity for customers to express their views about transmission investment plans. There may be some concern that customers have insufficient information for this purpose. No doubt there is scope to improve this information.

However, the main proposal in this paper is that customers need more than simply the opportunity to express an informed view. They need to be able to exercise a degree of control over whether a proposed transmission investment goes ahead or not. This in turn means that transmission companies and planning organisations will need to take into account - more explicitly than at present - whether the investments that they are proposing fully meet the needs of customers. Specifically, they will need to ensure that transmission proposals are more coordinated than at present, do not crowd-out generation investments where the latter would be more economic, are not unnecessarily expensive, and are adequate to meet all economic requirements of customers.

There is obviously a question of what powers these customers should have and how this control is exercised. Should they share these powers with transmission companies and regulatory bodies or supplant them? Is consensus a sufficient basis for expressing a view? Or should there be a more formal system with votes for each type of customer, and if so how should these votes be distributed? Of relevance here may be the extent to which these customers pay for the transmission system or particular elements of it.

To help assess these questions, the paper now gives some illustrations of how arrangements for empowering customers work in other countries and other utility sectors. Ultimately what is needed is to develop an approach that is best suited to the needs of the Australian transmission sector. This is discussed in the final section of the paper.

4. Evidence from UK: Lighthouses and Airports

We start with an example from an earlier era: the building and financing of British lighthouses in the nineteenth century.[8] Previously, economists generally considered that lighthouses were typical public goods that needed to be publicly supplied and financed and/or regulated. In fact, however, they were supplied by private provision and financed by lighthouse dues on users – that is, ships passing by who paid when they came into port. These dues were determined by the shipowners themselves, with a view to financing approved investments in lighthouses. Institutional arrangements involving users thus overcame a potential public goods problem while leaving decisions to the lighthouse users and builders. Within this framework (which was supported by legislation), transactions costs were not a bar to effective negotiations between the users, nor has it been suggested that the pattern of investment was insufficient or inefficient.

An interesting recent development is the encouragement by the UK airport regulator (the Civil Aviation Authority or CAA) of so-called "constructive engagement" between British Airports Authority (BAA) airports and their airline users.[9] The aim of this arrangement is that the airports and their users should agree the main elements of a business plan for the foreseeable future. This includes traffic forecasts, investment requirements and other parameters relevant to the CAA's price control review for the forthcoming quinquennial period 2008 - 2013. The CAA will need to satisfy itself that the interests of any parties not represented around the table are adequately protected. Subject to that, the intention is that the CAA will then accept those plans agreed by constructive negotiation rather than make its own determinations on these matters.

Previously, there had been numerous tensions between airlines and BAA. However, good progress is reported at BAA's two largest airports (London Heathrow and London

[8] R H Coase. "The lighthouse in economics", *Journal of Law and Economics,* 17(2) October 1974: 357-376.
[9] *Airports Review: Policy Update*, Civil Aviation Authority, 15 May 2006, chapter 8.

Gatwick). There has been substantial agreement on almost all the above matters. Moreover, the parties have reported improved relationships and a desire to continue the process beyond this price control period.

In contrast, agreement has not yet been reached at BAA's Stansted airport. There is a difference of view as to the case for an expansion here, with the (predominantly low-cost) airlines disputing the need for an extension of the size and expense and timing proposed by the airport. There are also political issues involved, since the government previously gave priority to an extension at Stansted in preference to the expansion plan at Heathrow favoured by many airlines.

While this constructive engagement process is not yet complete, UK experience to date suggests that users and airports are indeed capable of negotiating mutually agreed and acceptable airport investment plans. Failure to agree an investment is itself instructive, and may be a salutary constraint on excessive or untimely investment.

5. Evidence from Argentina: Public Contest method in electricity transmission

In 1992 Argentina reformed its electricity sector along similar lines to the UK, with considerable restructuring and privatization. This was generally deemed a success. [10] One rather novel aspect of Argentine reform initially attracted critical attention, namely the arrangements for transmission expansion. However, subsequent experience and research have shown the arrangements to have been remarkably effective in making transmission investment more efficient. The arrangement was as follows.

Existing transmission systems would be regulated on the basis of an incentive price cap, recalibrated every five years or so. However, major transmission expansions were no longer to be decided by the transmission owner or the regulator. They were henceforth the responsibility of the users of the transmission system. (Users here included generators, major consumers and distribution companies with responsibilities for supplying small consumers in their areas.) A new so-called Public Contest method required users to propose major expansions. All users within a defined Area of Influence of the expansion – the so-called beneficiaries of the expansion - would vote on the proposed expansions. Approved expansions were put out to competitive tender. All the users would then share the cost on the basis of their actual usage over an agreed amortization period.

The Public Contest method was adopted in order to avoid the inefficiencies and over-expansions of the previous era of public ownership. In economic language, the method was intended to overcome the incentive to gold-plating and the political pressures associated with regulated transmission. The users (or beneficiaries) of an expansion would be better-placed than the transmission companies or the regulator to decide whether the benefits of an expansion were worth the costs. The Public Contest arrangements were thus designed to maximize the role for market participants and competition, and to minimize the role for regulation.

[10] E.g. Michael Pollitt, "Electricity Reform in Argentina: Lessons for Developing Countries", Cambridge – MIT Institute Electricity Project, CMI Working Paper 52, September 2004.

Initial experience suggested to some that the method was unduly severe. In the mid-1990s, a major transmission expansion known as the Fourth Line was proposed to convey electricity to meet expanding demand in Buenos Aires. The Fourth Line had been long-expected and the regulator described it as 'much-needed'. But at the first vote the Line was rejected, though a subsequent proposal was accepted. Many held the rejection and delay to be an indication of the lack of success of the transmission expansion policy.[11] Some said that a voting method involving users would be unworkable because of transactions costs.

A colleague and I have examined the history of transmission and its regulation in Argentina.[12] On closer inspection, we find that the Fourth Line was not an economic project. The increased value of the electricity transmitted was less than the cost. Over time, the economic situation in the Argentine energy sector had changed. It was now more economic to build gas pipelines to Buenos Aires and to generate electricity there, than it was to build a new powerline to Buenos Aires. Criticism of the Public Contest method for delaying investment in the Fourth Line was therefore misplaced.

The Fourth Line experience was exceptional. Approval of that uneconomic project was largely explained by a particular provision for using accumulated transmission revenues to finance expansions in particular corridors. In general, the Argentine Public Contest method avoided uneconomic expansions while enabling numerous economic expansions to take place. It was characterized by mostly harmonious relationships between the parties rather than discord. Transactions costs were not a problem.

There was active competition to build the expansions that were put out to tender. The construction cost per kilometer of major lines was roughly halved. There was also innovation in construction methods.

There has been some discussion of the Area of Influence method used to determine beneficiaries and calculate their participation or vote. The calculation is done by the system operator using a simulation model based on the same scheduling model that it uses to determine nodal prices. There have been some concerns that this determines beneficiaries and votes in proportion to the usage of a new line instead of the benefits it confers, that it could be sensitive to the choice of reference node, and that it takes no account of externalities. Against this, the aim of the designers was to find a practical, familiar and relatively objective method that was generally accepted. This has been the case. In practice, the concerns mentioned have not proved a problem.

It is true that the national transmission system in Argentina is largely radial, so that external impacts of one expansion on other parts of the networks and on other users were relatively small. It is therefore interesting to note what happened when the same principles were applied to the sub-transmission network in Buenos Aires province, where the network is

[11] Most commentators cite the important study by Chisari, O.O., Dal-Bó, P., and Romero, C.A., "High-Tension Electricity Network Expansion in Argentina: Decision Mechanisms and Willingness-to-pay Revelation," *Energy Economics*, 23, 2001, pp. 697-715.

[12] Stephen C Littlechild and Carlos J Skerk, "Regulation of transmission Expansion in Argentina: Part I, State Ownership, Reform and the Fourth Line" and "Regulation of Transmission Expansion in Argentina: Part II, Developments Since the Fourth Line", Cambridge – MIT Institute Electricity Project, CMI Working Papers 61 and 62, The Cambridge-MIT Institute, 15 November 2004, available at http://www.electricitypolicy.org.uk/pubs/wp.html. Revised versions are in the course of a journal review process.

considerably more meshed. Essentially, the same method was applied and found satisfactory, even though there was provision for changing it by agreement. A supplementary method was developed for allocating the charges at each federal transmission node among the provincial users connected at that node.

A more significant issue at provincial level was the participation of provincial distribution companies as the main beneficiaries of sub-transmission expansion. There was initially a dispute as to whether the price controls set by the provincial regulator included provision for financing such expansions. Once that was resolved, the distribution companies and over 200 municipal cooperatives worked amicably to design, agree and finance a ten year plan for sub-transmission investment. They did so via a Regional Electricity Forum that included the transmission and sub-transmission companies as advisory members. The resulting Plan is in course of implementation but has been delayed by the economic crisis in the country.

Argentine experience shows that it is feasible to transfer decision-making power from transmission companies and regulatory bodies to transmission users, and to put proposed investments out to competitive tender. This approach brought about greater efficiency in Argentina by disciplining decisions about whether and how to make transmission expansions, and also by securing their construction and operation at lower cost.

6. Evidence from Chile: transmission expansion

The Argentine model reflected and improved upon a similar approach previously developed in Chile.[13] Under the 1982 Electricity Law, as supplemented in 1990, provided for open access to transmission systems. But pricing and expansion of the transmission system depended upon bilateral negotiations between interested users and the transmission owner, with other users not having to pay for the first five years. A few large users such as generation plants and large customers including distribution companies built their own transmission expansions. But the fear of free riding discouraged users from cooperating to share the costs of other transmission expansions. (The designers of the Argentine Public Contest method defined a more precise basis of cost allocation and charging in order to overcome this problem.)

In view of growing concerns about a lack of investment in the transmission system, the Electricity Law Amendment of March 2004 (the Short Law) defined a new way of calculating transmission tolls. It also created a new process to expand the transmission system with the cooperation of all parties, coordinated by the regulator.

In the main Trunk system, a Common Area of Influence is defined, within which generation companies pay 80 per cent and consumers 20 per cent of total transmission tolls. Outside that Area of Influence tolls are paid by generators if power flows towards the Area of Influence and by consumers if power flows out of it. Tolls are related by a formula to the value of the assets plus operating costs.

Every four years, a Trunk System Study determines tariffs in the Trunk system and also an expansion plan. New investments are put out to competitive tender. The Study is carried out by an international consultant and conducted by a committee comprising 8

[13] Juan C Araneda and Sebastian Rios, "Transmission expansion under market conditions: the Chilean experience", *IEEE Powertech Conference Proceedings*, St Petersburg, June 2005.

representatives: 2 from regulators, 2 from generation companies, 2 from transmission companies, 1 from distribution companies and 1 from large consumers. There is provision for appeal to a Panel of Experts if necessary. The process is coordinated by the National Energy Commission.

The new Amendment is considered to be a success. Within a short time several new transmission projects were identified and put out to tender. Three new entrants were in competition with the incumbent for the first major project.

7. The concept and practice of negotiated settlements[14]

In many jurisdictions around the world, utilities are regulated by a traditional form of litigation process along the lines of US regulation. But in many of these jurisdictions including in North America itself, market participants effectively make decisions about a wide range of matters that are conventionally thought to be the province of regulation by means of litigation. They do so by means of negotiated settlements.

Traditionally, the regulated utility would provide information and give testimony. This would be challenged in court by the regulatory body and by intervenors. Then the regulatory body would decide the case. The settlement approach typically begins with the same initial process during which the company is required to provide relevant information. Then, in contrast to the litigated or regulated approach, interested parties including user and consumer groups negotiate a settlement or 'stipulation' with the regulated company. They put this proposal to the regulatory authority, and it is typically confirmed.

This practice is apparently widespread. Settlements have been used in a wide variety of regulatory contexts.[15] At least one US state has actively demanded that a utility seek to achieve a settlement. I am told that settlements are widely used and supported in Australia, particularly in ports, freight rail infrastructure, gas pipelines and airports. However, there has been little economic analysis of the practice until recently. It may therefore be helpful to indicate how thinking and practice have developed, even though these settlements may not have focused on electricity transmission systems.

Settlements have traditionally been seen primarily as a way of economising on time and cost, or reducing uncertainty, compared to traditional regulation which proceeds by litigation. The implication is that the outcome is unlikely to be significantly different from the outcome of litigated regulation.

More recently, however, it has been suggested that settlements better serve the needs of the parties. This is not a new claim, but it is an aspect that seems to be increasingly appreciated. The reason is that regulators do not know the precise situations and preferences of the

[14] This section draws heavily on J Doucet and S C Littlechild, "Negotiated settlements: the development of legal and economic thinking", Electricity Policy Research Group Working Papers, No. EPRG 06/04, 2006, Cambridge: University of Cambridge at http://www.electricitypolicy.org.uk/pubs/wp.html, forthcoming in *Utilities Policy*, December 2006.

[15] One study instances water, electric and telephone rate cases; sale of an electric plant and various ratemaking and accounting aspects of nuclear plant; and competition in telecommunications and new telecommunications offerings of private line service and customer-owned coin-operated telephones. Petrulis, R C. "NRRI Report: Commissions Use Negotiated Settlements to Expedite Regulatory Process", *NRRI Quarterly Bulletin*, 1985, 6: 379-390, at p. 381.

parties involved. They have to make judgements according to their own perceptions and preferences rather than those of the parties. Their choice is not necessarily what the parties themselves would choose, and therefore not necessarily as acceptable. Some consumer advocate practitioners put it this way.

> [W]hen the regulator makes the decisions, everyone loses something, and parties have no control over what they lose. In the negotiation process, each party chooses which among the many points it is willing to lose in order to gain something else. Although this may sound like a distinction without a difference, in fact, the trade-offs arrived at voluntarily are much more stable and effective. Negotiated settlements are actually more democratic because all parties participate in the decision. As a result the terms are more likely to be implemented with enthusiasm and effectiveness than if they had been imposed from above by a regulator. Furthermore, in an atmosphere of trust and negotiation, more information is freely shared, with the result that more comprehensive solutions can be developed.[16]

The greater involvement of parties themselves means that a wide range of issues is susceptible to settlement, and "some kinds of utility cases can be better resolved through negotiation than litigation."[17] This is because "negotiation allows the parties themselves to make the trade-offs, instead of leaving it to the regulator to split the difference."

Negotiated settlements also allow greater flexibility and innovation, and can achieve results that lie beyond the traditional litigated approach. It has been argued that the flexibility inherent in the settlement process may be by far the most telling ground for its encouragement, particularly in the evolving competitive context.

> Flexibility is especially important now, as the utility marketplace moves from integrated monopolies to multi-party and/or unbridled competition. Since full and effective competition will take years to accomplish, parties to utility proceedings must effectively function in this largely undefined transitional period. The creation of the new competitive environment will be far more successful if stakeholders are able to talk openly, share ideas, and challenge the traditional approaches that once suited the monopoly marketplace. … By exploring new approaches, parties will be able to fashion solutions beyond the regulatory authority of a commission when they do not violate any important regulatory principle or practice.[18]

---

[16] G J Palast, J Oppenheim and T MacGregor. *Democracy and Regulation: How the public can govern essential services*, London and Virginia: Pluto Press, 2003, p. 96.

[17] Palast et al. "These include energy conservation or efficiency programs, and payment and other assistance to the poorest citizens of society." (p. 88) "Besides energy conservation cases, other types of cases have been successfully negotiated and settled, including the guiding principles of electricity industry restructuring in Rhode Island and Massachusetts, price-setting cases in New York and elsewhere, and cases in which the regulator was reviewing the operating performance of generating plants owned by an electric utility." (pp. 96-7)

[18] A P Buchmann and R S Tongren, "Nonunanimous Settlement of Public Utility Rate Cases: A Response." *Yale Journal of Regulation,* 1996, 13: 337-345.

8. Evidence from US: negotiated settlements for gas pipelines at FERC

In the US, negotiated settlements appear to have been initiated or at least strongly encouraged by the Federal Power Commission (FPC) during the early 1960s as a way of working off a large backlog of regulatory applications. The view that settlements should become an objective of regulatory policy seems to have been accepted at the Federal Energy Regulatory Commission (FERC), which superseded the FPC in 1977. By 1980 settlements were reached in approximately two-thirds of all electric utility rate cases there, and in 1986 in over 70 per cent of gas pipeline rate cases. It was once claimed that FERC "resolves approximately 80 per cent of its caseload through negotiated settlements."

Settlements evidently developed in various State commissions as well as federal ones. It would not be surprising if the majority of US States have now recognised settlements of some kind.

Recent research on FERC practice confirms the claims about the extent of settlements and the benefits of this approach. One study set out to determine how the settlement process at FERC differed from the formal adjudicatory process, how the outcome differed, and why the players settled a case. [19] The author examined 41 natural gas pipeline rate cases from 1994 to 2000, of which 34 were settled in whole, 5 were settled in part, and two were fully litigated. He noted that a typical case involved many issues.[20] He found that "the informal settlement process differs fundamentally from the litigation process, thus leading to significantly different outcomes."[21] The most significant outcome was one that FERC could not impose in a litigated case.

> Perhaps the most innovative settlement outcome is the rate moratorium provision in 21 of the 39 settlements in the sample. It is remarkable that the rate moratorium, a simple form of price cap regulation, arises endogenously from the settlement process of the traditional rate of return cases. FERC is prohibited by the governing statute from imposing a rate moratorium on the pipeline in a litigated case, but is free and willing to approve settlements with rate moratoria. (p. 142)

There is perhaps a question as to how far these rate moratoria were intended as a simple form of price cap in the sense of incentive regulation, as opposed to a way of providing a time at which the terms would be reviewed. However, the conclusion is not in doubt, that the main purpose of settlement was not to reduce uncertainty about regulatory decisions, but to achieve an outcome that could not be achieved under litigation.[22]

---

[19] Zhongmin Wang, "Settling Utility Rate Cases: An Alternative Ratemaking Procedure", *Journal of Regulatory Economics*, Vol. 26, No. 2, September 2004, pp. 141-164.

[20] These include "the quality and variety of the services, the level and structure of the service prices, the inputs, and many other contractual issues such as the contract length and the timing of the following rate case". (p. 142)

[21] "In order to reach the 'just and reasonable' end result for a litigated case, FERC follows an issue-by-issue merits determination procedure. That is, FERC makes a separate decision on each of the issues, based on the findings of fact and its rules, policy and precedents. During the settlement process, however, the players could focus directly on the end result by bargaining over all the issues together as a package, so that they can make tradeoffs among the issues." (p. 142)

[22] "The empirical findings suggest that the players settle a pipeline rate case mainly to make the tradeoffs that cannot be made during the litigation process. Avoiding the uncertainty in the formal adjudicatory process is of secondary importance because the litigation outcome is apt to be fairly predictable, and for some cases is

For present purposes, the main point is not to emphasise the innovative nature of negotiated settlements approved by FERC. Regulated transmission lines in Australia can already be made subject to incentive price caps, for example. Rather, the purpose is to show that market participants – pipelines and their users or customers – are indeed able to come to agreement on rate cases. Moreover, this approach has improved relationships between the parties. That is surely conducive to better coordination and more efficient investment.

9. Further evidence from US: negotiated settlements (stipulations) in Florida

The evidence and conclusions at FERC are mirrored by those in Florida. [23] The Office of Public Counsel (OPC) has negotiated many settlements (stipulations) of rate cases before the Florida Public Services Commission (PSC). The OPC was set up to represent the citizens of Florida in utility matters. It often worked in tandem with representatives of consumers, particularly (but not only) larger ones.

For gas, electricity and telephones sectors in total, stipulations were agreed in 31 per cent of earnings reviews. These stipulations brought tangible benefits. From 1976 to 2002 stipulations accounted for 77 per cent of rate reductions, but only 0.7 per cent of allowed rate increases.

There is evidence that these settlements secured a much better deal for customers than regulation would have done. Across these three sectors, the average value of a rate reduction was $49.6m with a stipulation and $6.7m without. In the electricity sector, nine stipulations accounted for $3.8bn worth of rate reductions. Detailed examination suggested that most of these reductions were attributable to the stipulations. They would not otherwise have been achieved. At the very least they were achieved earlier than they otherwise might have been.

What did the utilities gain from settlements in return for these very significant rate reductions? They saved some costs, but these savings were relatively small, estimated at under 0.5% of the amounts involved in the settlements. Perhaps companies avoided some uncertainty or embarrassment of public hearings. But mainly they achieved innovative modifications to the traditional Public Service Commission procedures, sometimes in the face of advice by Commission staff.

One example of such a modification was more flexible accounting procedures (including deferring accounting provisions, and either not increasing depreciation or even reversing it).

known." (p. 143) "The settlement approach to ratemaking substantially expedites the regulatory process and leads to creative solutions that cannot be achieved through ratemaking." (p. 162)

[23] Stephen Littlechild, "The bird in hand: stipulations, the consumer advocate and utility regulation in Florida", unpublished manuscript, 7 April 2003. Some initial results were published in "Consumer Participation in Regulation: stipulated settlements, the consumer advocate and utility regulation in Florida", Market Design 2003 Conference, Stockholm, 17 June 2003, Slide presentation and conference paper (called Report) are in *Proceedings* at http://www.elforsk-marketdesign.net/archives/2003/conference/conferencemain_en.htm. Also Stephen Littlechild, "Stipulations, the consumer advocate and utility regulation in Florida." Electricity Policy Research Group Working Papers, No. EPRG 06/15, Cambridge: University of Cambridge, 2006 at http://www.electricitypolicy.org.uk/pubs/index.html.

More importantly, however, companies and users were often able to agree the adoption of revenue-sharing incentive arrangements lasting several years instead of traditional rate of return regulation or earnings-sharing schemes. That is, they were able to get rid of a limit on profits in return for accepting a limit on prices or revenues. In effect, they managed to achieve an incentive price-cap approach to regulation, which the traditional US framework of regulation via litigation was unable to deliver.

It remains to be seen whether Florida's experience is unique, associated with the person appointed as Public Counsel during this whole 25 year period. Whether it would generally be helpful to introduce or increase the role of consumer advocates in Australia is beyond the scope of this paper. But the idea of negotiated settlements with customer representatives there deserves further consideration.

10. Evidence from Canada: negotiated settlements for oil and gas pipelines[24]

Negotiated settlements have been encouraged by the National Energy Board (NEB) in Canada since the late 1980s and widely adopted since the mid-1990s. In contrast to the FPC in the US, the NEB was not driven by a desire to reduce a backlog of cases, although there was certainly an aim to reduce the frequency and duration of regulatory proceedings. Government deregulation policy was also an influence.

Importantly, oil and gas pipelines and shippers realised they could achieve their ends more effectively and more surely with settlements than they could by conventional litigation. Multi-year incentive agreements developed particularly rapidly among all the pipelines. Settlements have also been used to specify and improve service quality, revise information and publication requirements, and agree investments and risk-sharing arrangements for new facilities. One particularly innovative settlement provided for the transition of one pipeline's gas gathering and processing services from one type of regulation (conventional litigation) to another (a specially designed scheme of light-handed regulation). This latter scheme provided for negotiated settlements with individual shippers, information provision to facilitate price discovery, interconnection terms to reduce barriers to entry, and a complaint-handling procedure that envisaged the NEB as the last resort rather than the first.[25]

With the exception of one gas pipeline during the four-year period 2001-4, negotiated settlements have superseded the litigation of oil and gas pipeline toll and tariff cases for at least the last decade. They have also streamlined the regulatory process. For example, settlements last between 50 per cent and 150 per cent longer than previous litigated outcomes, and NEB processing times have been cut by between a quarter and two-thirds. Settlements have also provided a new forum for collaboration and increased value creation between pipelines and their customers. Observers and participants are in no doubt that this could not have occurred under the traditional litigated approach to utility regulation.

---

[24] This section draws heavily on J Doucet and S C Littlechild. "Negotiated settlements and the National Energy Board in Canada", Electricity Policy Research Group Working Papers, No. EPRG 06/[ ]. Cambridge: University of Cambridge 2006, at http://www.electricitypolicy.org.uk/pubs/wp.html. forthcoming]

[25] On this settlement that provided for light-handed regulation, see also N J Schultz. "Light-handed regulation", *Alberta Law Review*, 37(2) 1999: 387-418.

The key contributions of the NEB seem to have been twofold. One was to modify the settlement guidelines in 1994 to say, in effect, that if the process of settlement was acceptable (i.e. was open to all interested parties and reached general agreement) then the Board would deem the outcome just and reasonable and would not 'cherry-pick' the settlement. This assured the parties that their negotiations were not in vain. The other contribution was the 'generic cost of capital' decision that provided an explicit and uniform basis for annually updating the cost of capital of each pipeline in the absence of a settlement. This removed a main source of dispute and of market power, and thereby facilitated negotiation and agreement on the provision of services of increased value to customers.

In parallel with the development of negotiated settlements, NEB has put increased reliance on contracts instead of traditional regulatory procedures as a means of approving gas pipeline expansions.[26] Before granting approvals, the NEB must be satisfied that the pipeline expansion is necessary and that the associated tolls are just and reasonable. Traditionally, the NEB prescribed the provision of detailed information concerning supply, demand, purpose, justification and economic evaluation. It also required detailed information about project-specific gas markets and calculation of tolls based on a cost of service methodology with rate base, rate of return, rates of depreciation and operating costs prescribed by the NEB.

Since 1995, however, the NEB has approved a number of pipeline expansions based on risk-sharing agreements between the pipelines and shippers under which the shippers contract for capacity and agree to pay specified tolls. The existence of the contracts has sufficed to determine that the pipeline is needed and that the tolls are just and reasonable. With one exception these tolls were established by contract and not subject to cost of service methodology.

Ongoing research on the use of settlements at the Energy and Utilities Board (EUB) in Alberta suggests that the EUB takes a more 'hands on' approach than the NEB, and places more emphasis on generating information for the record.[27] Nonetheless, settlements have been increasingly adopted in Alberta, and take roughly half as long to complete as litigated cases. There, too, settlements have also been innovative. For example, one settlement introduced performance based rate making in the gas sector; another settlement was the means of implementing the Regulated Rate Option (RRO) in the electricity sector. The latter is an innovative form of retail price control based on a risk-sharing approach to energy procurement contracts, which is unlikely to have been possible under traditional litigation.

11. Summary and implications of international experience

The examples given above differ in various respects. They cover actual experience in a variety of different sectors and countries: lighthouses and airports in the UK, electricity transmission in Argentina and Chile, gas pipelines at FERC in the US and utilities generally in Florida, oil and gas pipelines in Canada and electricity utilities in Alberta.

[26] Keith F Miller, "Energy regulation and the role of the market", *Alberta Law Review*, 37(2) 1999: 419-436.

[27] J Doucet and S C Littlechild. "Negotiated settlements and the Alberta Energy and Utilities Board" (research in process 2006).

However, the experiences all have certain important lessons in common. In all cases, important aspects of the operation of these sectors are determined by customers of the network utility or by agreement with them. In some cases (eg UK airports), users agree demand forecasts and investments but not charges for usage. In other cases (eg FERC and Florida) users typically agree charges but not investments. In yet other cases (eg Argentina and Canada) users often agree both. In some cases (eg Argentina) there are rules for voting and these are closely prescribed. In other cases (eg Chile) there is a committee with defined membership. In yet other cases (eg the UK, US and Canada) there are no such rules and the process is one of seeking mutual agreement.

In all these cases, and often in face of initial scepticism, it has generally proved possible to obtain substantial agreement between customers themselves, and between customers and network providers. There has been no significant challenge to the ensuing pricing or investment proposals. All parties prefer this process to conventional regulation. There has been substantial improvement in relations between the parties. There is also a wish to continue and extend this means of operation.

When customers are allowed a significant role in decision-making, the role of regulation is altered but not eliminated. Conventionally, the decision to regulate a utility or other sector means that the information, judgements, preferences and decisions of the market participants are replaced by the information, judgements, preferences and decisions of the regulatory agency. Even if the agency wishes to replicate the effects of a competitive market, it still makes all the key decisions. This has well-known limitations, associated with the information available to the regulatory bodies and the influences that might be brought to bear on them. The active involvement of customers changes that. Subject to a satisfactory settlement process, the regulatory agency allows market participants to make the key decisions themselves, using their own information, judgements and preferences.

In some circumstances the purpose of regulation might be precisely to prevent market participants from taking their own decisions, and to substitute regulatory decisions reflecting a different view of the public interest. If so, it may not be appropriate to give a greater role to customers. But much regulation is not of this kind. It is often justified by some perceived 'market failure' such as market power or externalities or a free rider problem. In such cases there is no presumption that the judgements of market participants are inadequate. In this case, an active role for customers can be encouraged. In doing so, the regulatory agency may need to take steps to address any specific market failure. But it does not have to substitute its own judgements on the main investment decisions.

In all the cases studied above there is a more limited but nonetheless still critical role for regulation. Essentially, it is enabling the market to work. To use the words of an early proponent, "agencies should be viewed not primarily as decision makers … but as a means of helping the parties … work out a result that is both mutually acceptable and in the public interest".[28]

12. Adapting these ideas for electricity transmission investments in Australia

[28] T D Morgan. "Toward a Revised Strategy for Ratemaking." *University of Illinois Law Forum,* (1) 1978: 21-78.

The success of customer involvement in these various countries suggests that it is worth considering its use in the Australian transmission sector. There are obviously many different ways of doing that.

Following practice in Argentina, one possibility would be substantially to remove the role of transmission companies and regulatory bodies in actually deciding on transmission investments. One could require users rather than transmission companies to propose and make investment decisions, and specify voting rules for users that might or might not also specify the sharing of charges. Such an approach could be accompanied by an obligation to put out to tender any proposed expansion, at least above a specified size. Such an approach may warrant consideration in those states where the nature of decision-making by regulators and transmission entities is associated with excessive investment.

If this is considered a too radical change from present arrangements, something less severe might be considered. For example, given that some transmission planning bodies already exist in Australia, an existing planning entity might be responsible for putting forward a proposed transmission programme. However, this programme would be assessed by representatives of customers that ultimately foot the bill. In this context, the provisions in Chile would seem to merit consideration. The Australian planning bodies could report to a Transmission Committee comprising representatives of all kinds of interested parties especially customers (including generators and end-users) as well as transmission companies. This would not just be an advisory committee: approval by the Transmission Committee would be required before a transmission programme could go ahead.

In states where there is no explicit transmission planning body in Australia at present, it does not mean that one needs to be created, at least not by the federal or state governments. Argentine experience suggests the feasibility of a transmission expansion (and reinforcement) plan being drawn up by an organisation of customers (always including generation companies and distribution and/or supply companies as well as large users).

It would be possible to encourage this approach within the present federal and state regulatory frameworks. One could design or modify statutory duties to encourage the role of customers without removing an ultimate role for regulation. For example, the Alberta Energy and Utilities Board Act 1995 (s132) provides that "the Board must recognize or establish rules, practices and procedures that facilitate negotiated settlement". A UK utility regulator is presently obliged to 'protect the interests of consumers, wherever appropriate by promoting effective competition'. It would be possible to add the clause 'and by promoting negotiated settlements or other arrangements agreed between licensees and consumers'.

Encouraging interested parties to agree in this way might be particularly appropriate where the concern is primarily associated with coordination and timing. It is for consideration whether such an approach (on its own) would go far enough in states where there is concern about excessive investment by the transmission company. Even there, however, the transmission company might see advantage in an agreed transmission programme rather than one that is constantly subject to dispute.

In all these cases, it is for consideration whether there should be weighted voting among customers, and if so whether votes should be weighted by transmission usage or transmission charges paid. The simple requirement for approval by a customer Committee might suffice to ensure that proposed projects were soundly based and better reflected the needs of customers.

There will naturally be questions about who would represent end-user customers. However, in each particular context it should be possible to identify organisations that could fill this role – indeed, they would tend to identify themselves. The very largest industrial and commercial consumers can represent themselves. In all countries there are generally groups representing large and medium-sized energy users. Smaller businesses might be represented by local chambers of commerce or trade associations. There are often government-appointed consumer bodies with responsibilities to protect and advise domestic/residential users. A variety of non-government organisations represent subsets of interested parties.[29]

There would need to be provisions for customers to obtain relevant information from the companies, perhaps via the regulator. Customer groups could commission expert advice as required. In some jurisdictions there is provision for the settlements to cover the legitimate costs of such intervenors. In Alberta the EUB can decide to reimburse such costs. The EUB is taking steps to ensure that such reimbursement does not stimulate inefficient duplication of evidence and argument.

The initial arrangements in Argentina made no explicit provision for a regulator to propose and enforce transmission investments in the absence of proposals from users. Over time, provision was made for transmission companies or the system operator to propose investments that might be of particular relevance to security of supply. In Australia it might be considered advisable for a regulatory backstop in the event of the companies and users failing to agree on certain aspects of investment.

A regulatory body might be able to take certain actions to diffuse issues where agreement is unlikely to be reached in order to facilitate agreement on other issues. For example, the NEB specifies the allowed return on capital in the event that customers and the utility fail to agree a rate. The CAA does not expect airports and airlines actually to agree on this rate of return but hopes that parties will nonetheless agree on an investment programme, presumably in light of the return on capital that the CAA is expected to allow. More generally, in the absence of a provision to put new construction out to tender, a transmission regulator might price the capital expenditure items 'on the menu' of a possible transmission expansion programme, but leave it to consumer groups to specify the items that should appear on the menu and to choose which items to accept.

Working out all the details of an approach for fully involving customers in the choice of transmission investments in Australia is beyond the scope of the present paper. The best approach could vary from one state to another. It could usefully be put for the consideration of customer groups themselves. Experience elsewhere suggests that a suitable

[29] To illustrate, in Florida intervenor parties participating in electricity settlements have often included (in addition to the Office of Public Counsel) the Florida Industrial Power Users Group and various of the Office of Attorney General, Florida Retail Federation, Commercial Group, Federal Executive Agencies, American Association of Retired People, Sugarmill Woods Civic Association, Lake Dora Harbour Homeowners Association, Coalition of Local Governments, Lee County local government, Florida Consumer Action Network, South Florida Hospital and Healthcare Association, Coalition for Equitable Rates, Florida Alliance for Lower Electric Rates Today, a variety of individual large users such as Occidental Chemical Corporation, White Springs Agricultural Chemicals, Tropicana Products, Georgia Pacific Corporation, Publix Supermarkets Inc, Dynegy Midstream Services LP, and even interested individuals such as Thomas and Genevieve Twomey.

approach can be found to provide results that are acceptable to all the parties and preferable to conventional regulation.