grid australia
BACKBONE OF THE NEM

30 November 2012

Mr Phillip Weickhardt
Presiding Commissioner
Electricity Network Inquiry
Productivity Commission
GPO Box 1428
Canberra City ACT 2601

Via email: electricity@pc.gov.au

Dear Phillip

Electricity Network Regulation – Submission on Draft Report

Grid Australia welcomes the opportunity to provide a submission to the Productivity Commission's (Commission) Draft Report for the Inquiry on Electricity Network Regulation.

Grid Australia agrees with the Productivity Commission that transmission planning arrangements must be focused on delivering the most efficient outcomes for consumers, and that the transmission network must be planned to capture national efficiencies. This should include delivering a nationally consistent approach to transmission planning and investment arrangements in each jurisdiction. .

However, the Productivity Commission's recommendation that AEMO takes on responsibility for augmentation investment decision making in relation to the shared transmission network is not the most effective way to deliver these outcomes. Instead, Grid Australia considers that the National Electricity Objective (NEO) would be best promoted through the implementation of the Australian Energy Market Commission's (AEMC) proposed framework for transmission regulation (with some enhancements).

The Commission's draft recommendations appear to stem from a number of important omissions. Among other matters the Commission has:

- Not sufficiently considered the integration of its proposals with wider market design requirements. This includes the interaction with recent Rule changes relating to the economic regulation of networks and recommendations made by the AEMC. It also includes the AEMC's Transmission Frameworks Review (TFR) proposal to develop optional firm access for generators operating in the wholesale electricity market.

- Unduly discounted the potential for commercial incentives to drive more efficient transmission service provision where augmentation investment, replacement investment,

- and asset maintenance are all carried out by commercially motivated transmission network service providers.

- Underestimated the operational shortcomings that are evident in the current Victorian transmission arrangements represented by a separation of the network investment decision maker and the party accountable for service performance.

Furthermore, numerous claims have been made about the relative efficiency of Victorian style transmission arrangements throughout this review process.[1] Grid Australia is concerned that these claims have been given weight that is not supported by the facts. This is discussed in more detail in the body of this submission.

On those specific matters that the Commission was asked to review in its Terms of Reference, namely the use of benchmarking and the efficiency of the framework for the delivery of transmission interconnection investment, Grid Australia generally supports the Commission's findings. Specifically that the following findings are endorsed:

- While benchmarking clearly has a role in economic regulation, it is not yet suitable as a revenue setting method. This is particularly the case for transmission networks; and

- There is no evidence of under-investment in interconnectors.

We trust that this submission will be useful to the Commission and look forward to further constructive engagement with the Commission and staff on these important matters for the electricity sector.

Yours sincerely

Rainer Korte
Chairman
Grid Australia Regulatory Managers Group

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[1] See for instance: AEMO, *Electricity Network Regulation – Submission to Issues Paper,* 11 May 2012 and Department of Primary Industries, *Submission to Inquiry into electricity network regulation,* 17 May 2012.

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Electricity Network Regulation

Submission in response to the Productivity Commission Draft Report

November 2012

Powerlink TransGrid ElectraNet electricity transmission TRANSEND SP AusNet

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1 Summary

Grid Australia welcomes the opportunity to provide a submission to the Productivity Commission's (Commission) Draft Report for the Inquiry on Electricity Network Regulation. Grid Australia represents the owners of all the major electricity transmission networks in the National Electricity Market (NEM). As a result, its members have a direct and substantial interest in the matters addressed in the Draft Report.

Grid Australia agrees with the Productivity Commission that transmission planning arrangements must be focused on delivering the most efficient outcomes for consumers, and that the transmission network must be planned to capture national efficiencies. This should include delivering a nationally consistent approach to transmission planning and investment arrangements in each jurisdiction. .

However, the Productivity Commission's recommendation that AEMO takes on responsibility for augmentation investment decision making in relation to the shared transmission network is not the most effective way to deliver these outcomes. Instead, Grid Australia considers that the National Electricity Objective (NEO) would be best promoted through the implementation of the Australian Energy Market Commission's (AEMC) proposed framework for transmission regulation (with some enhancements).

The Commission's draft recommendations appear to stem from a number of omissions. Among other matters the Commission has:

- Not sufficiently considered the integration of its proposals with wider market design requirements. This includes the interaction with the AEMC's recent response to Rule change proposals relating to the economic regulation of networks. It also includes the AEMC's Transmission Frameworks Review (TFR) proposal to develop optional firm access for generators operating in the wholesale electricity market.

- Unduly discounted the potential for commercial incentives to drive more efficient transmission service provision where augmentation investment, replacement investment, and asset maintenance are all carried out by commercially motivated transmission network service providers.

- Underestimated the operational shortcomings that are evident in the current Victorian transmission arrangements represented by a separation of the network investment decision maker and the party accountable for service performance.

Furthermore, numerous claims have been made about the relative efficiency of Victorian style transmission arrangements throughout this review process.[1] Grid Australia is concerned that these claims have been given weight that is not supported by the facts. This is discussed in more detail in the body of this submission.

On those specific matters that the Commission was asked to review in its Terms of Reference, namely the use of benchmarking and the efficiency of the framework for the delivery of transmission interconnection investment, Grid Australia generally supports the Commission's findings. Specifically that the following findings are endorsed:

- While benchmarking clearly has a role in economic regulation, it is not yet suitable as a revenue setting method. This is particularly the case for transmission networks; and
- There is no evidence of under-investment in interconnectors.

<u>Frameworks for efficient transmission planning can be enhanced</u>

Grid Australia agrees that there is scope for improvement in the regulatory framework for transmission networks. However, under any framework for transmission planning arrangements, there are two separate issues to consider:

- *what* is the planning standard; and
- *who* applies the standards.

The Commission's assessment would benefit from clearer consideration of these separate but related issues in arriving at its final position.

Once an assessment is made against a complete set of criteria, it is evident that the AEMC's proposed transmission planning and investment framework, with some enhancements, is the best option.

The key elements of an enhanced regulatory framework for transmission networks based on the AEMC's work are:

- Planning to an economically efficient level of reliability with the standards expressed deterministically. The risk of an outdated deterministic standard is addressed by allowing the actual timing of a project, or the nature of the preferred option, to vary from the deterministically expressed standard in certain circumstances. This would be if certain agreed criteria are met, or there has been a material change in input assumptions. In this case an economic cost

[1] See for instance: AEMO, *Electricity Network Regulation – Submission to Issues Paper,* 11 May 2012 and Department of Primary Industries, *Submission to Inquiry into electricity network regulation,* 17 May 2012.

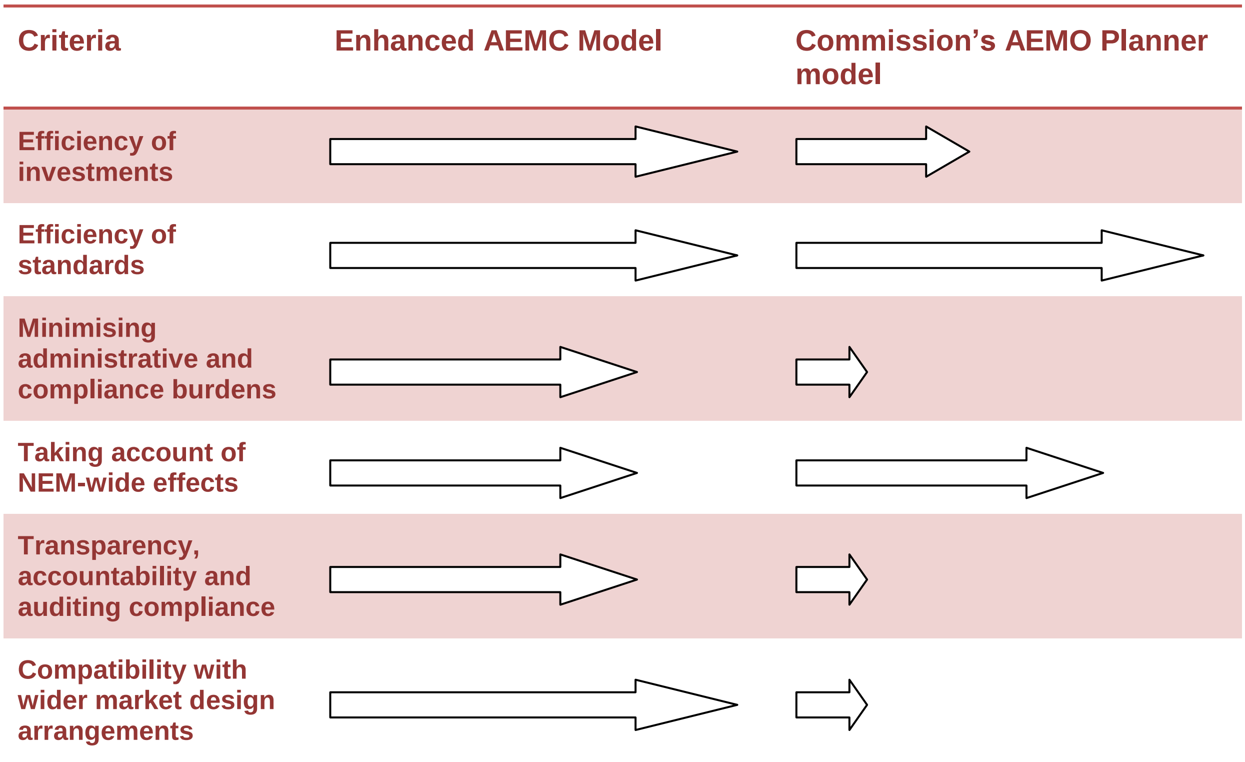
benefit (probabilistic) analysis would be undertaken by the TNSP at the time of investment decision making.

- Improved financial incentives for profit motivated TNSPs as the means of achieving a more efficient type, timing and cost of projects. Administrative obligations should also be applied as a complementary measure where financial incentives are less feasible.

- Strengthened oversight and accountability of planning and investment decisions, not least to ensure that NEM-wide effects are given due consideration in network plans.

Grid Australia has reproduced the Commission's illustration in table 15.2 of its Draft Report of the AEMC hybrid model and AEMO planner model to compare an AEMC model with enhancements proposed by Grid Australia (enhanced AEMC model), to the Commission's preferred model. Grid Australia has also identified some additional criteria that the models should be assessed against and included these in this comparison.

Figure 1: Illustration comparing two national models against assessment criteria



The following table provides a summary of Grid Australia's assessment of the enhanced AEMC model against these criteria, as will be explored in this submission.

Table 1: Assessment of enhanced AEMC Model Against Criteria

Criteria	Model description	Assessment
Efficiency of investments	For-profit TNSPs making investment decisions. Strengthened financial incentives for efficient capex – e.g. capex efficiency benefits sharing scheme. AER oversight of ex-ante revenue proposals, contingent projects for uncertain projects. Coordination of NTP and TNSP annual planning publications.	Harnesses the known efficiency advantages of profit-motivated businesses. Contingent projects mechanism provides revenue closer to the time of investment for uncertain projects. Aligns investment decision responsibility with service accountability. Able to gain the efficiency benefits arising from responses to regulatory incentives complemented by administrative and compliance requirements to achieve efficient outcomes
Efficiency of standards	Economically derived planning standards expressed deterministically. Scope to deviate from default standard where agreed criteria are met.	Delivers economically efficient reliability while delivering necessary transparency and accountability
Minimising administrative and compliance burdens	Planning standards set independently from the body making the investment decision on a periodic basis with scope to vary within 5 year regulatory period in accordance with agreed criteria. Use well designed investment incentive schemes, including contingent projects and, possibly, AER designed mechanisms to accommodate material variations between forecast and actual demand growth, and service incentive schemes to complement administrative and compliance mechanisms to achieve efficient outcomes.	Provides articulation of a reference standard to assist in overseeing compliance by TNSPs. Ensures confirmation of the applicability of the standard each time projects are assessed. Avoids costs of within period probabilistic assessments when not warranted (while still delivering an economic level of reliability).
Taking account of NEM-wide effects	TNSPs responsible for planning and investment with strengthened NTP oversight as per AEMC TFR recommendations. NTP undertakes strategic national planning identifying anticipated national flow path network development in response to supply and demand trend scenarios over the longer-term. AEMO with Last Resort Planning Power (LRPP) – including power to compel investments	Transmission networks are not just about national flow paths, rather most of the task of transmission planning relates to meeting local and regional needs including joint planning with DNSPs. Therefore, AEMC solution better integrates local, regional and cross border investment decisions. In any event, the national oversight arrangements ensure that cross border co-ordination is properly integrated into investment planning. Other NEM-wide effects are managed over an operational time horizon. This is already undertaken nationally by AEMO as the system operator.

Criteria	Model description	Assessment
Transparency, accountability and auditing compliance	TNSPs continue to report to the AER on planning and investment decisions with AEMO oversight of TNSP planning and investment decisions; coordination through published planning documents, RIT-Ts and planner of last resort	Provides for independent expert oversight while maintaining investment responsibility with the party responsible for service delivery. This also provides confidence to stakeholders through transparency and accountability. The presence of deterministically expressed planning standards provides a more transparent reference point for compliance monitoring. Enables the transmission business to have control of all the elements related to transmission service outcomes e.g. augmentation investment, replacement investment, asset life extension projects, operation and maintenance. This makes it easier to hold the TNSP accountable for service and cost outcomes resulting from the combination and co-ordination of these factors.
Compatibility with wider market design arrangements	Examples of this include improved arrangements for connecting new entrant generation capacity; aligns with AEMC OFA model with TNSP incentives; leverages off existing allocation of resources and experience. The recent Rule change decision by the AEMC on the economic regulation of electricity networks clearly contemplates a role for incentive regulation of transmission capital expenditure.	Minimises uncertainty, complexity and compliance costs for third parties, such as connecting generators by reducing the number of parties to each agreement. Maintains clarity of accountabilities. Material efficiency benefits arise for customers in the long term by effectively integrating the commercial drivers of regulated transmission services with the generation market, particularly in supporting efficient overall investment across both sectors.

This submission expands on these matters by examining and developing the relevant assessment criteria for transmission planning and investment arrangements. It then explains in more detail how the modified version of the Australian Energy Market Commission's proposed transmission planning and investment framework best meets these assessment criteria.

2 Overarching comments and purpose of this submission

At the outset Grid Australia acknowledges the considerable work that has gone into the Commission's report. The Commission has produced a report that is wide-ranging and seeks to tackle many of the matters concerning the regulation of electricity networks that are presently under consideration across a variety of forums. Grid Australia has necessarily focused on those aspects of the Draft Report directly related to transmission networks. Within that context there are many aspects of the Commission's report that Grid Australia supports, including:

- Recognition that superior outcomes can be achieved with profit motivated businesses responding to well-designed incentive regulation, and recognition that there is some work to be done to improve the financial incentives NSPs face
- That it is important that stakeholders have confidence that the framework will promote the long-term interests of consumers
- That benchmarking clearly has a role in economic regulation, but not as a revenue setting method (which is particularly the case for transmission)
- The approach to setting planning standards in each jurisdiction should be improved and a new approach is needed that properly considers the full economic costs and benefits of network investment
- There is no evidence of under-investment in interconnectors
- There is merit in progressing the Optional Firm Access model as a concept as it has the potential to facilitate better network utilisation and deliver improved wholesale market outcomes, and
- Actions to strengthen the capability and resources of the Australian Energy Regulator (AER) will work to improve the overall effectiveness of the regulatory framework.

The purpose of this submission is to focus on those transmission aspects of the Commission's Draft Report where Grid Australia has reached a different conclusion on how best to promote the NEO. This includes consideration of the two separate but potentially related questions of:

- Who has responsibility for transmission planning and investment as it relates to the shared transmission network?
- What planning standard should be applied and how the standard is applied?

Grid Australia has recently commissioned two reports that help inform the Commission's Inquiry.

The first is a report by Evans & Peck in response to a CME report for the Energy Users Association of Australia (EUAA) that compares the relative performance outcomes of transmission networks.[2] The Evans & Peck report finds that there are a number of inaccuracies in the CME report and that the relative starting positions of the networks in each jurisdiction is critical to understanding revealed outcomes.

The second report has been prepared by NERA and discusses the transmission planning arrangements as they apply in North America.[3] This is in response to the Commission's references to the North American arrangements to support a particular approach for transmission planning. The NERA report finds that caution should be taken when making comparisons between North America and Australia given the important differences in the frameworks that apply in these jurisdictions.

Both the Evans & Peck report and the NERA report are attached to this submission.

The remainder of this submission is structured as follows:

- Section 3 examines the criteria for assessing which approach to transmission planning and investment best promotes the NEO and explains why additional criteria are warranted. It also describes a model that better meets the NEO.
- Section 4 assesses the enhanced AEMC approach to transmission planning and investment against these criteria.
- Section 5 examines some of the fallacies that may be unduly influencing the Commission's thinking. For example, analysis correlating Victorian investment and price outcomes with either more efficient ownership or planning models in that state is flawed. Furthermore, references to market arrangements in other countries have been made without full regard for the context within which those arrangements have evolved and now operate.

3 Criteria for assessing transmission planning frameworks

The Commission has assessed various transmission planning models against a number of criteria. These are explained in section 15.7 of the Draft Report. The Commission's criteria are:

- Efficiency of investments
- Efficiency of standards
- Minimising administrative and compliance burdens

2 Evans & Peck, *Response to CME Report Prepared for Energy Users Association of Australia – A comparison of outcomes delivered by electricity transmission network service providers in the National Electricity Market,* November 2012

3 NERA, *US Transmission Planning Arrangements – Competitive Procurement and Independent Planning Model, A Report for Grid Australia,* 15 November 2012.

- Taking account of NEM-wide effects, and
- Auditing compliance to ensure reliability and efficiency in the long run.

Grid Australia agrees that these criteria are relevant to the achievement of the NEO. However, Grid Australia considers that there are additional criteria that should be considered when assessing transmission planning arrangements against the NEO, these are:

- **Transparency and accountability** – Grid Australia proposes that the "auditing compliance" criterion be enhanced to recognise the importance of transparency of outcomes in transmission regulation, with well-defined accountability for those outcomes. Transparency will enhance the confidence of parties in the regime including the efficiency of network or non-network options chosen, as well as providing information to enhance the planning and investment decisions of large consumers and generators. Accountability for outcomes is essential for ensuring those outcomes are met, including minimising the possibility of uneconomic risks being taken by network planners.
- **Effective integration with wider market design arrangements** – this relates to the ability for the proposed arrangements to effectively integrate with and support wider market design considerations. These include efficient accommodation of new connections, proposals to manage transmission access risk (such as the proposed OFA model), and the Rules for incentive regulation of transmission recently reviewed and amended by the AEMC.

<u>Improving transmission planning frameworks</u>

The Commission has identified what it considers to be a number of problems with the current transmission frameworks, principally that:

- TNSPs do not face effective incentives for efficient network investment;
- The current planning standards do not provide for an economically efficient level of reliability; and
- The current framework does not properly accommodate the consideration of NEM-wide effects.

Grid Australia agrees (as does the AEMC[4]) that there is scope for improvement in each of these areas. Indeed, Grid Australia has advocated the need for improvements to the regulatory framework in these areas for some time now.[5]

[4] AEMC, *Transmission Frameworks Review, Second Interim Report,* 15 August 2012, p.v.

Each of these matters has either recently been addressed or is in the process of being addressed through on-going work by existing market institutions, most notably, the AEMC. The two most important projects from the AEMC in this respect are its consideration of the AER's Rule changes on the economic regulation of networks and its on-going Transmission Frameworks Review (TFR).

The work of the AEMC demonstrates that changes within the context of existing frameworks best serve the achievement of the NEO:

- The AEMC's Final Rules on the Economic Regulation of Network Businesses provides the AER with the tools to develop a comprehensive set of incentives for efficient transmission investment. A particular feature of these new Rules is the scope to substantially strengthen the incentive to minimise capital expenditure through the option for a symmetrical and continuous sharing scheme.[6] This can facilitate better harmonisation of incentives between operating and capital expenditure as well as to service incentives and obligations. Grid Australia submissions to this Rule change process advocated the strengthening of financial incentives on capital expenditure.[7]

- The AEMC has reinforced through the TFR its earlier position that transmission planning standards need to be improved so that they deliver an economic level of reliability. By placing due weight on the importance of transparency and accountability the AEMC has recommended that economically derived planning standards be expressed deterministically. This is a position that Grid Australia has endorsed for a number of years.[8]

- The AEMC has proposed in its most recent TFR report that there are benefits from a more direct role for the National Transmission Planner (NTP) in providing oversight on the planning activities of TNSPs. The intention is to ensure that NEM-wide effects are properly taken into account in planning while also ensuring that the efficiency benefits of profit-motivated TNSPs can be harnessed for the benefit of consumers. This is consistent with Grid Australia's

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5 See for instance: Grid Australia, *Submission to Transmission Reliability Standards – Draft Report,* 3 June 2008, Grid Australia, *Consolidated Rule Request – National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2011, Response to AEMC Consultation Paper,* December 2011.

6 The AER would also have discretion regarding how to address technical issues in the design of such schemes, including for instance, the treatment of the deferral of projects between regulatory periods and of the impact of matters such as changes between forecast and actual demand on realised efficiency gains.

7 Grid Australia, *Consolidated Rule Request – National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2011, Response to AEMC Consultation Paper,* December 2011.

8 Grid Australia, *Submission to Transmission Reliability Standards – Draft Report,* 3 June 2008

position that regional transmission planning by profit-motivated TNSPs be effectively integrated with strategic national planning by the NTP.[9]

- The AEMC has proposed the introduction of Optional Firm Access for generators. This has as a by-product the creation of a comprehensive set of output requirements for TNSPs, thus permitting greater scope for applying financial incentives for cost reduction. Grid Australia has supported the further consideration and development of this model.[10]

- The AEMC has recommended that the responsibility for providing connection services within the boundary of the existing network remain the sole responsibility of TNSPs. The AEMC's view on this matter appears to be based in part on the view that separate ownership and operation of connection assets is unlikely to be efficient. Grid Australia submissions to the TFR have supported this position. Further, Grid Australia has emphasised that timely and commercially flexible connection arrangements are needed in order to facilitate new entrant generation and new customer connections.[11]

  The provision of connection services in Victoria is unduly complex because of the shared responsibilities for transmission services arising from AEMO's shared network investment direction role. Every connection agreement requires AEMO and SP AusNet as parties. The AEMC's proposal to leave the shared network investment role with the asset owners simplifies this aspect of the wider market arrangements.

4 Improved transmission planning and investment framework

A more economically efficient transmission network can be achieved by implementing the key elements of the AEMC's recommended approach to transmission planning and economic regulation. The key elements of this model are:

- Planning to an economically efficient level of reliability with the standards expressed deterministically

- Improved financial incentives for profit motivated TNSPs so that the type, timing and costs of projects are efficient, and

- Strengthened oversight and accountability of planning and investment decisions.

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[9] Grid Australia, *Electricity Network Regulation, Response to the Productivity Commission Issues Paper,* April 2012.

[10] Grid Australia, *Transmission Frameworks Review, Submission in response to AEMC Second Interim Report,* October 2012.

[11] Ibid.

The table below sets out the enhanced AEMC approach in further detail along-side the Commission's description of its preferred model. This is based on table 15.3 in the Commission's Draft Report. The table also provides a summary of the advantages of the enhanced AEMC approach compared to the Commission's preferred approach for each of the relevant elements.

Table 2: Comparison of alternative planning standard approaches

	AEMC Approach (enhanced)	Productivity Commission's Preferred Approach	Advantages of Enhanced AEMC Approach
Type of reliability standard or planning	Economically derived standards expressed deterministically	Probabilistic planning	Economically efficient reliability provided with transparency and accountability
Standards contained in?	National template. Reliability to become a national function	Reliability to become a national function	National approach equal between models
Who sets the standard?	Independent body from the body making the investment decisions in consultation with consumer representatives and stakeholders[12]	AEMO in consultation with transmission businesses	Separates the responsibility for setting the standard from who applies the standard
Who makes augmentation investment decisions?	Transmission businesses with oversight from AEMO and the AER	AEMO in consultation with transmission businesses	Substantially increases the scope for financial incentives to be used and profit motives harnessed for efficiency. Aligns infrastructure capability investment with service responsibility and risk
Process for planning or setting standards	Independent body sets standards designed to be international best practice in consultation with consumer representatives and stakeholders and the methodology to be followed in applying cost benefit (probabilistic) assessment to review efficient timing of investments	AEMO probabilistic planning process, peer reviewed and designed to be international best practice	More robust, transparent and consultative assessment of input assumptions. Lower administrative costs.

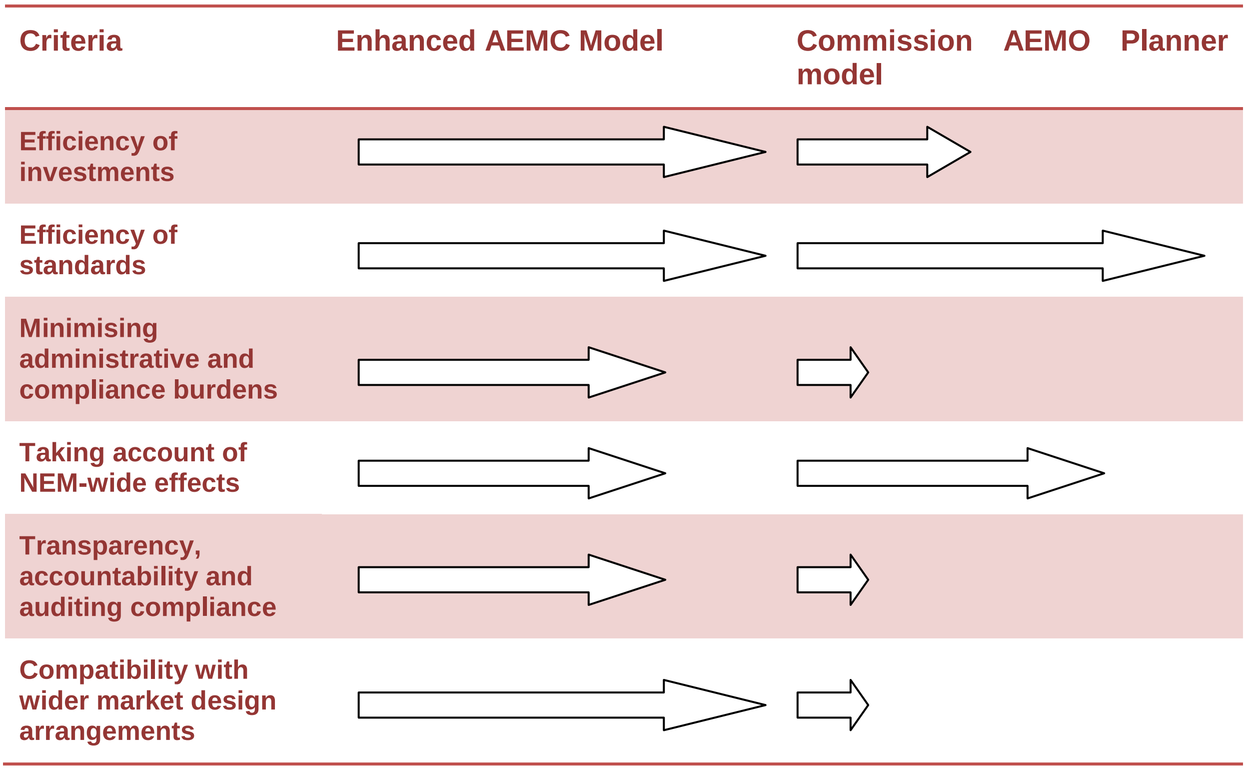
[12] Noting that the independent body may or may not be AEMO, the key aspect, however is that there is independence between the setting of standards and their application.

	AEMC Approach (enhanced)	Productivity Commission's Preferred Approach	Advantages of Enhanced AEMC Approach
How is revenue allocated?	Combination of ex-ante revenue allowance and contingent projects with AEMO, AER and customer oversight	Negotiation between AEMO and TNSPs before start of small projects (with AER approval). Separate AER revenue determination process before start of large projects	Allows for incentives to help drive efficient behaviour with scope for windfall gains or losses minimised through contingent projects. Avoids potential uneconomic delays in projects commencing.
Independent cost-benefit analysis or RIT - T	Businesses to conduct RIT-T with scrutiny by AEMO and oversight of the AER	AEMO to conduct RIT-T	Increased accountability on test application
Last resort planning power	AEMO but with added power of being able to direct investment if the need is considered critical	AEMO but with added power of being able to direct investment if the need is considered critical	Equal increase in accountability and oversight

The remainder of this section considers the components of the enhanced AEMC model and the Productivity Commission's preferred model against both organisations' criteria. Grid Australia considers that the 'enhanced AEMC model' will deliver an economically efficient transmission system with necessary transparency and accountability.

In addition, by leveraging off the key elements of the existing framework the enhanced AEMC model is able to deliver at least the same benefits as the Commission's preferred model, but at much lower cost and risk to market participants and institutions.

Figure 2: Illustration comparing of two national models against criteria



4.1 Efficiency of Investment

Criterion achieved through:

- Assigning investment decision making to profit motivated network businesses with appropriate financial incentives for efficiency complemented by administrative measures and requirements
- Opening the way for the use of financial incentives to further deliver efficient investment while applying administrative obligations for those areas where financial incentives alone may not be effective
  - Ensuring an appropriate allocation of projects between the ex-ante revenue cap and contingent projects to minimise the scope for windfall gains or losses in the presence of very lumpy projects
- Aligning the planning and investment decision making responsibility with service responsibility so that the full complement of options is available to service providers to manage service delivery risks
  - This, in turn, allows efficient trade-offs to be made between capital and operating expenditure solutions, between augmentation and replacement capital investment decisions, and between transmission and distribution investment decision making decisions

The Commission acknowledges that profit motivated businesses with appropriate financial incentives are more likely to identify efficient options for a given reliability constraint than a not-for-profit entity.[13] Grid Australia fully endorses this view and agrees that a pre-requisite for this to occur is a framework for effective financial incentives supplemented by appropriate administrative obligations.

The Commission's draft recommendation is that the planning and investment decision making role for shared network augmentations be given to a not-for-profit body in the form of AEMO. This has a number of important implications including substantially reducing the scope of possible decisions upon which incentives can be applied as well as separating the party responsible for planning from the party responsible for service provision.

This position appears to have been made, in part, based on a concern that it is too difficult to apply effective financial incentives to TNSPs' capital expenditure decisions. To the extent that this is the Commission's position, it needs to be tested as part of the consultation process more expressly than appears to be the case in the Commission's draft report.

There are two separate issues to consider here.

- Firstly, there is the question of whether it is feasible to design effective incentives at all to drive efficient transmission investment. If the answer to this is 'yes', then there is a potentially valuable role for commercial incentives, possibly in conjunction with administrative arrangements. If the answer to this question is 'no', then all that is left are administrative and compliance controls to achieve efficient outcomes.

- The second question to be answered is, if there is a role for commercial incentives then what is it and what form should it take? The AEMC has clearly formed the view that there is at least some role for commercial incentives in driving efficient transmission augmentation. This is embodied in its Rule change decision on the economic regulation of electricity networks and in its findings as part of its Second Interim report on the TFR.

Based on the work that has been done by the Commission to date, the case has not been made for concluding that financial incentives cannot perform an important role in encouraging efficiency in transmission capital expenditure decisions. As such, it is premature to move to reliance on administrative arrangements alone to achieve efficient transmission investment outcomes.

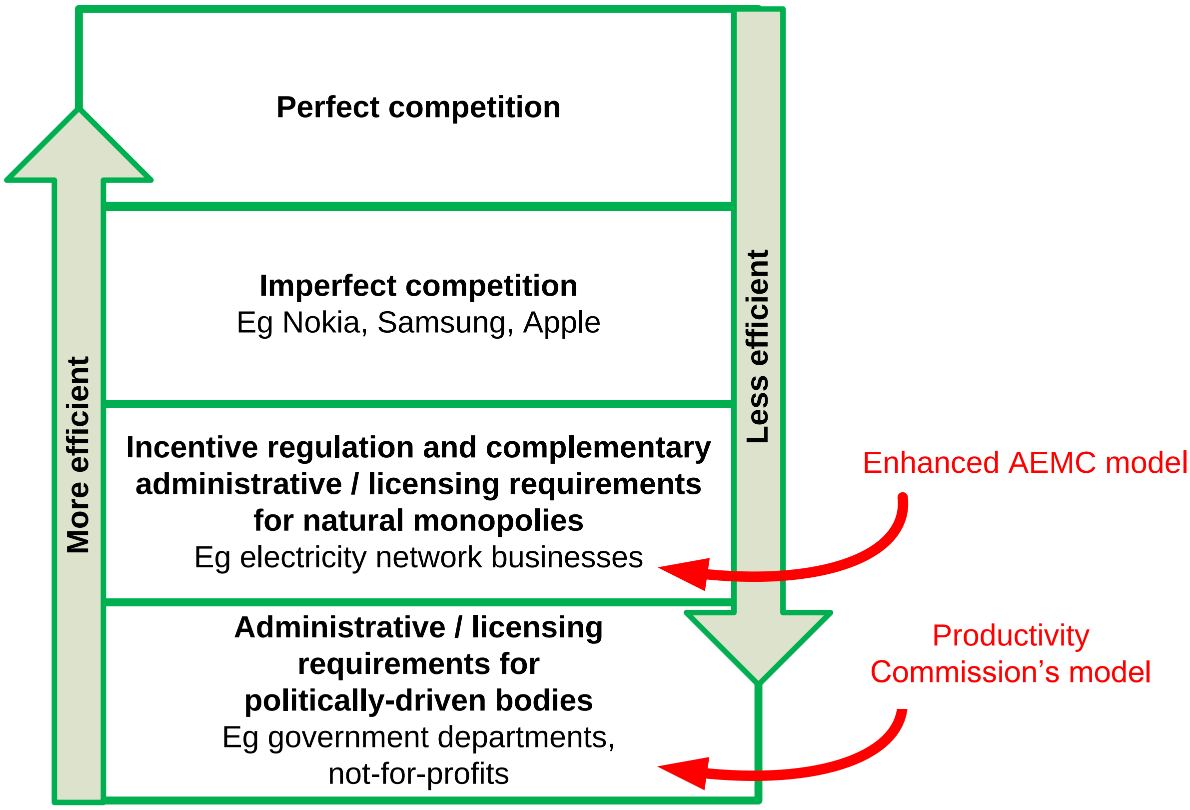
Instead, the evidence to date suggests that financial incentives in the context of transmission networks are able to promote more efficient outcomes. Indeed, contrary to the view that incentives might be ineffective for transmission networks, in a number

13 Productivity Commission, *Electricity Network Regulatory Frameworks, Draft Report,* October 2012, p.517.

of aspects financial incentives are more straightforward to apply in transmission than for distribution.[14]

Importantly, however, it is inherent in all areas of regulation – and the designing of incentive schemes in particular – that complex issues arise and that perfection cannot be achieved. The question for the Commission is whether an imperfect incentive scheme is superior to the alternative of total reliance on administrative controls. Grid Australia contends that, as with other parts of the economy, outcomes are superior in a circumstance where profit motivated firms are responding to financial incentives, even if these are supported by administrative requirements (e.g. Rules compliance and licence requirements).

Figure 3: Driving efficiency from various market structures



Grid Australia recommends that the Commission focus on what lessons can be taken from the existing approach and what improvements can be made. Doing so can mean the full benefits of profit motivated TNSPs can be harnessed for the efficient delivery of transmission services.

[14] For instance, given transmission investment is typically based on a limited number of discrete projects it is often easier to identify genuine efficiency gains within a period, and also to detect where individual projects are deferred between periods (whether or not a project has been deferred affects the size of the efficiency gain that is made and so should influence the efficiency reward to the NSP).

4.1.1 Stronger financial incentives for the efficient type, timing and cost of projects

The AEMC has recently decided to make changes to the Rules that significantly strengthen and broaden the AER's powers to develop a comprehensive approach to financial incentives for transmission businesses. In particular, the new Rules create the opportunity for effective incentives for efficient capital expenditure. Features of this framework include:

- A capital expenditure incentive objective and guideline
- A capital expenditure sharing scheme
- An ex-post prudence test of capital expenditure
- An AER statement on the efficiency of all capital expenditure, and
- More explicit powers for the AER to interrogate revenue proposals and substitute forecasts.

Grid Australia supports the AER having a range of tools available to it to deliver a balanced set of financial incentives for efficient service delivery. Financial incentives provide the opportunity and incentive to find ways of meeting the desired objective through lower cost means, or to provide a superior outcome for the same cost, including by taking account of new information as it becomes available. This is because the prospect of a financial reward or penalty encourages TNSPs to find more efficient initiatives that might not have otherwise been identified.

The AEMC in its Second Interim Report for the TFR explicitly considered whether the Victorian not-for-profit planner model would likely deliver more efficient investment than investment decision making by a profit-motivated TNSP. Its view at this stage is that a not-for-profit planner is likely to result in less efficient network investment:[15]

> *"Finally, as discussed further in section 5.8.2, the Commission considers that the current arrangements in Victoria, characterised by functional separation and a not-for-profit entity operating making investment decisions, are likely to result less efficient outcomes than would be the case with an integrated TNSP that is subject to financial incentives, provided those incentives are appropriately designed."*

<u>Financial incentives with complementary administrative arrangements</u>

The Commission appears to be concerned that creating service incentives that sufficiently counteract the stronger incentives to minimise cost is problematic for transmission. Grid Australia acknowledges that it may not be possible or appropriate to apply financial incentives to all aspects of a TNSP's performance. However, this is

[15] AEMC, *Transmission Frameworks Review, Second Interim Report*, 15 August 2012, p. 71.

overstating the difficulties with implementing an incentive regime. In particular, where a regulated business is provided with financial incentives to minimise expenditure:

- it is *essential* that there is confidence that service standards are not compromised in order to earn the reward from cost reductions, as this behaviour may reduce rather than enhance economic efficiency, and

- it is *desirable* if regulated businesses can be provided with financial rewards to encourage them to provide the optimal level of service performance, so that the regulator can withdraw from prescribing minimum service standards.

Even if financial incentives cannot be applied to all relevant dimensions of output (service performance), substantial gains will still arise from providing financial incentives for cost reduction, the only proviso being that measures are required to ensure this does not come at the expense of service.

In almost all regulated sectors there will be gaps in the dimensions of output to which financial incentives can be provided. This is an issue that exists across the entire economy, and is therefore not unique to transmission or even to regulated businesses. The profit motives of firms that operate in competitive markets mean that they also may have an incentive to minimise cost at the expense of other outcomes that are valued by society, such as with respect to safety, the environment, and the treatment of the labour force.

However, the fact that this problem exists does not mean that competitive markets are abandoned altogether. Instead obligations are placed on businesses to behave in certain ways or to provide transparency about the actions they take.

While financial incentives already exist for service performance for TNSPs, just like in the wider economy these are supported by additional regulatory obligations, including. The regulatory obligations and transparency requirements to support these incentives include:

- Licence obligations to maintain a certain level of service and reliability for consumers.

- Reporting requirements to allow the regulator to monitor and compare performance over time and between TNSPs, including a new requirement on the AER to assess the comparative efficiency of TNSPs on an annual basis.

- Oversight by regulatory bodies, including a Last Resort Planning Power should any necessary projects be identified that have not been undertaken by TNSPs.

The liability faced by commercial businesses with respect to a failure to deliver with respect to regulatory obligations has a direct and real impact on transmission businesses. This is because the risk these liabilities create impact on profit projections which in turn can affect the value of a business. Further to this, the reputational risk and public scrutiny that would be associated with a manifest failure to meet service obligations is also an important driver of behaviours that should not be summarily dismissed.

Alignment between revenue allowance and project commencement

The Commission also appears to be concerned about revenue being provided to businesses too far in advance of investment decisions being made. The concern appears to be that given the drivers for transmission investment this might lead to either windfall gains or losses for TNSPs.

However, this seems to be a matter of incentive design rather than evidence that there is no role for commercial incentives in driving efficient transmission investment. There are, in fact, a number of workable solutions that exist to mitigate the scope for either windfall gains or losses for TNSPs. Further to this, the AER will now have the discretion under new Rules for the economic regulation of NSPs to design incentive mechanisms to address such issues.[16]

The box below provides one such mechanism that might be considered to identify the impact that changing demand has had on efficiencies that occurred during the period. In effect, this option neutralises the effect of demand on project timing – this is a more feasible prospect for transmission than distribution given projects are more easily identifiable.

Box 1: Possible approach to minimising windfall gains and losses under incentive regulation

In many incentive schemes, the reward or penalty that a regulated business receives for a change in performance is based on the difference between an ex ante forecast of the relevant performance metric and the result that is achieved. This approach is taken in the service target performance incentive schemes and operating expenditure efficiency benefit sharing schemes for both transmission and distribution. It is also implicit where a forecast of capital expenditure is included in the setting of a price or revenue cap.

However, transmission augmentation projects can be very large, and their timing critically affected by the forecast of demand, which is largely outside of the control of the transmission businesses. The implications of these factors is that applying a simple incentive scheme to transmission augmentation projects could deliver material windfall gains or losses (depending

16 It should be noted that providing an ex-ante revenue allowance that TNSPs can beat is a key element of the incentive for TNSPs to strive to reduce costs and so reveal the efficient costs of service provision. This, in turn, is one of the key advantages of incentive regulation over rate-of-return regulation. That is, providing this incentive for the efficient cost to be revealed is considered to deliver an overall benefit to society that is greater than could be achieved by funding individual projects as they arise. Therefore, it should be preferable to resolve any issue of potential windfall gains through adjustments to the ex-ante revenue cap in order to allow the full benefits of financial incentives to be achieved.

upon whether demand forecasts turn out to be too high or too low), which explains the preference of some of the consumer representatives for excluding such projects from incentive schemes.

- An alternative approach to excluding augmentation projects from an incentive scheme is to attempt to remove the demand-related "windfall" element from the rewards and penalties under the scheme. One possible approach for achieving this outcome would be as follows. First, include a forecast of augmentation expenditure in the capital expenditure that is included under the revenue cap that is based upon the best forecasts of demand available at the time. As discussed elsewhere in this submission, converting economically derived standards into a deterministic equivalent makes it more straightforward to link demand and expected capital expenditure needs.
- Secondly, at the end of the regulatory period, re-run the models that were used to forecast augmentation expenditure using the actual demand that was observed over the period. This step could be made easier by the AER generating a number of forecasts of augmentation expenditure during the preceding review, with each scenario corresponding to different forecasts of demand, which is undertaken already by the TNSPs that use a probability-weighted average for capital expenditure across different scenarios for demand.
- Thirdly, calculate the business-induced efficiencies in augmentation expenditure by comparing the actual augmentation expenditure to the adjusted forecast. This would allow the demand-induced "windfall" element to be removed from the measured change in efficiency, while still including (and thereby encouraging) savings in the cost of the project, or savings from being able to defer the project (including through undertaking demand-side measures).

This last step would permit the "windfall" element to be removed from the reward or penalty that may have accrued during the previous regulatory period, as well as permitting this to be excluded from any carry-over of capital-related efficiency benefits into the next regulatory period. It is observed here that while undertaking such a project-by-project adjustment may appear at first sight to be complex or intrusive, the "lumpiness" that characterises projects in the transmission sector makes such a project-by-project adjustment feasible. Moreover, as discussed below, the option would remain to remove particularly large or uncertainty projects from the revenue cap and treat them instead as a contingent project.

The approach set out above would require assessment and implementation details developed, but would appear to address some of the Commission's concerns. It is noted that developing such a mechanism would be within the AER's powers under the new capital expenditure incentive rules that the AEMC has proposed and there other possible design options that could emerge from the AER process to address concerns.

There is also already a mechanism within the current framework that allows particularly uncertain projects to be excluded from the ex-ante revenue cap. This is the contingent project mechanism. This mechanism excludes revenue from the revenue cap where there is a chance the project may be required within the regulatory period, but there is insufficient certainty to make an ex-ante revenue allowance for it. As such, similar to the Commission's preferred approach, TNSPs are only provided with revenue for certain projects where a trigger is met, such as a positive assessment under a RIT-T.

4.1.2 Taking advantage of synergies through a single profit motivated entity

Grid Australia considers that the effectiveness of financial incentives, and in turn the efficiency of investment, is strengthened where the party responsible for service delivery is also able to have the full complement of options available to it to meet service obligations. This is because faced with balanced, and continuous, incentives for capital and operating expenditure businesses will have the financial incentive to make appropriate trade-offs for the efficient achievement of service performance obligations.

Figure 4a illustrates this point in relation to transmission service provision.

Conversely, separating the planning function from the responsibility for service performance means that commercial businesses are constrained in their options to meet service performance obligations. The implications of this separation is that it either increases the risks to business of being able to meet their obligations efficiently or dilutes the allocation of responsibility for the performance of the business.

Figure 4b illustrates this point in relation to transmission provision.

Separating the planning and investment decision making functions from other functions related to service delivery function also reduces the scope for financial incentives to drive synergies across those functions. For example the way in which the following functions interact is relevant to arriving at efficient transmission systems:

- Transmission connection investments
- Asset replacement investments
- Plant life extension projects
- Asset maintenance strategies
- Agreements with third parties to gain access to non-network options for resolving a constraint
- Small investments or other schemes to improve the transfer capability of the current network assets, and

Figure 4a: Capturing synergies between planning and investment and service provision under the enhanced AEMC model

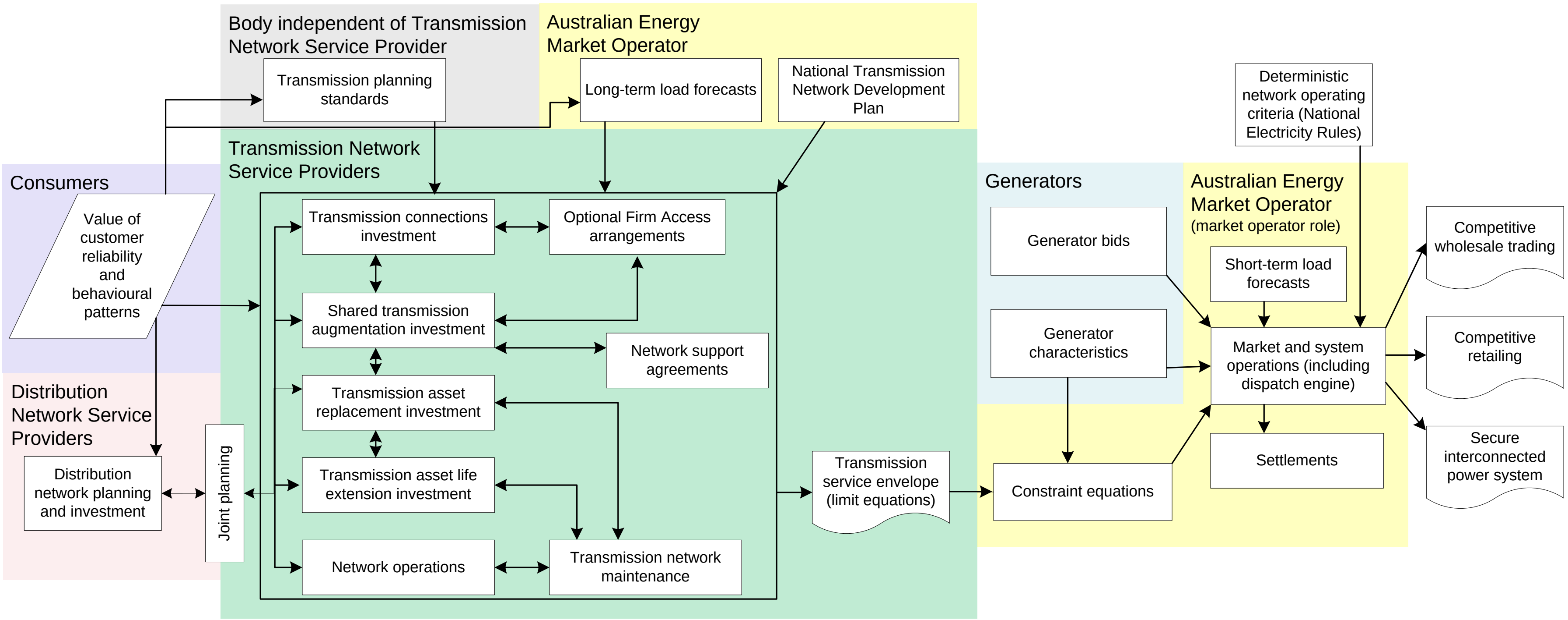
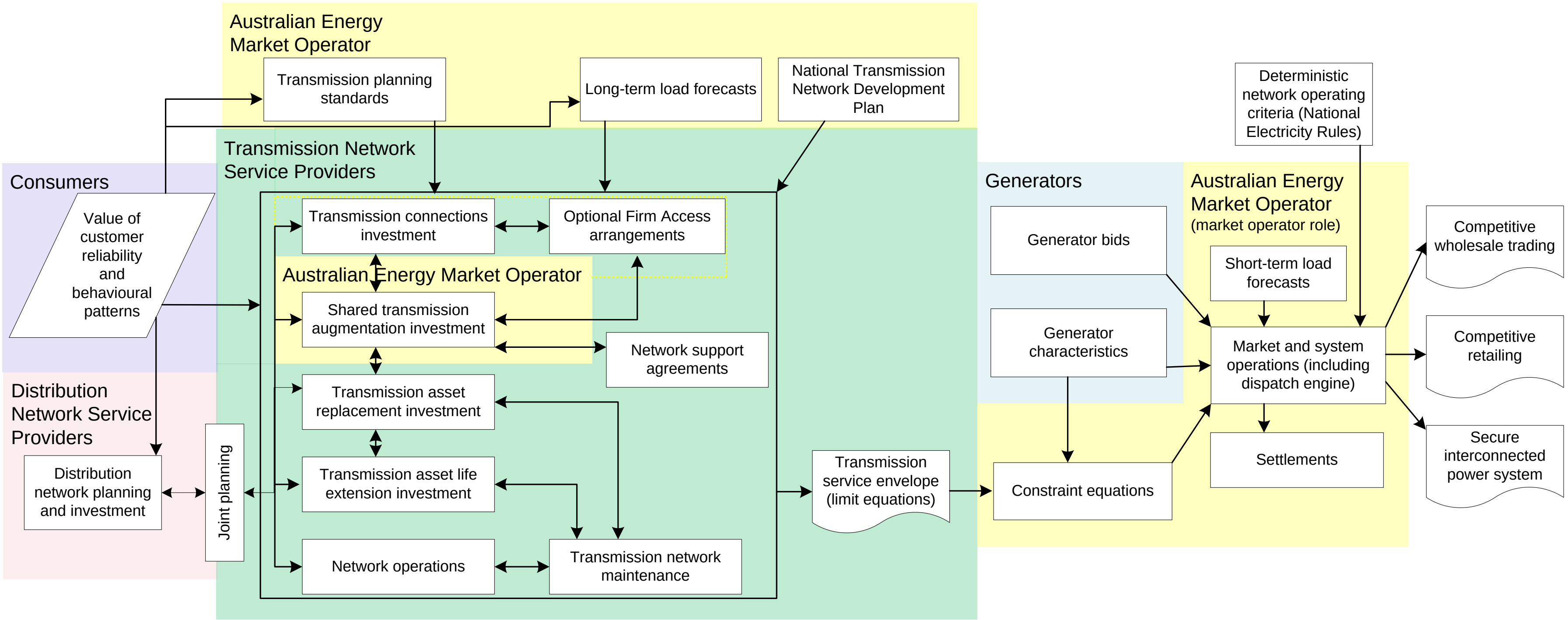


Figure 4b: Interaction between planning and investment and service provision under the Commission's model



- Co-ordinating with distribution businesses to achieve efficient overall investment across transmission and distribution systems. This is particularly relevant given the potential for increased complexity as a result of an increasing focus on smart grids, embedded generation, demand response and smart meters.

The trade-offs between these functions can have material consequences. For example, in NSW the distribution network service provider Ausgrid and transmission network service provider TransGrid estimate that savings, possibly hundreds of millions of dollars, are achieved through successful joint planning and careful integration of augmentation and replacement programs.

Ausgrid has a program of replacing a significant number of inner Sydney metropolitan 132 kV cables over the next decade. Coincidentally TransGrid has a need to optimise its 330 kV supply into the Sydney CBD over the next decade. Through close and effective joint planning between the organisations TransGrid is able to optimise its 330 kV supply solutions to the Sydney CBD while minimising the number of 132 kV cables Ausgrid needs to replace. The savings in avoiding 132kV cable replacements alone are in the order of tens to, possibly, some hundreds of millions of dollars.

It is also relevant to note that the challenges of applying incentives when there is a separation of the planning and investment function from the network operation function are already being experienced in Victoria. An example of this is identified in the following box.

Box 2: Example of reduced response to financial incentives in Victoria

Challenges with the application of incentives in Victoria have been experienced with respect to the application of the market impact element of the Service Target Performance Incentive Scheme (STPIS). This element of the STPIS creates an additional penalty to a TNSP where the non-availability of an asset causes a material market impact, which is defined as a change in the marginal cost of a constraint of $10/MWh or more. The intention is to provide a sharp incentive on TNSPs to ensure that assets are in service when an outage would have a material impact on the market.

Typical actions of a TNSP to minimise the impact of the penalty from the market impact element of the STPIS are to reschedule work to a time when lower market impact is less likely, minimising the outage time, and/ or utilising approaches that do not involve an outage at all.

For TNSPs that have planning and investment responsibility, and in that case are responsible for providing constraint equations, there is the opportunity to review and fine tune network capability. This can either be for the specific prevailing conditions at the time of the outage, or possibly resulting in more general application. In Victoria AEMO is responsible for the constraint equations (as they are in all jurisdictions), but outage scheduling and the market impact incentive are on the network owner. Where responsibilities are separated it is not practical for this type of analysis to be undertaken and for decision making to be done in near real time, which is necessary for outage scheduling in response to market signals. This is predominately because the transmission planning function in Victoria does not operate in this timeframe and does not bear the incentive to do so.

> It is noted that SP AusNet and AEMO seek to work together to implement the incentives to make them more effective. For example, AEMO and SP AusNet are currently collaborating to apply the Network Capability Improvement Parameter of the STPIS.
>
> A further complication with respect to the market impact incentive arises in Victoria due to the tripartite contractual arrangements for connecting parties. Connecting parties in Victoria that require shared network augmentation to affect their connection make this agreement with AEMO. AEMO then contracts with SP AusNet for the work to be undertaken. This work is likely to involve a network outage and, as a consequence, possibly a penalty to SP AusNet under the market impact incentive. The fact that SP AusNet does not have the direct contractual arrangement with the connecting party for all aspects of the connection leads to difficulty and complexity for SP AusNet to negotiation on this incentive. The connecting party and is instead borne by SP AusNet. This means that the connecting party has no incentive to optimise the timing of the outage to minimise its costs to the market or, for that matter, to choose to pay the penalty so that it can proceed with its preferred timing for the outage.

Further, and as discussed more in section 4.6, the ability to apply commercial incentives on TNSPs to take on an enduring obligation with respect to providing Optional Firm Access (i.e. bearing some of the financial impact on market participants) as proposed by the AEMC would be severely constrained where there is a separation of network investment and service obligation functions.

<u>Synergies between transmission planning and investment and system operation</u>

The transmission network has an important role in the management of the electricity system in real time. Therefore, it is necessary to consider whether there are sufficient synergies between transmission planning and investment and system operation to have a single party undertake both functions.

Even where there are synergies between transmission investment and system operation, assigning the investment role to a not-for-profit entity would mean that there would be no opportunity to impose financial incentives on the trade-offs that might exist between each of the functions. Therefore, the prospects of maximising the benefits of any synergies are considerably reduced.

Further to this, much of the information that is required to make operational decisions as a system operator is held by TNSPs. This is because TNSPs are the ones responsible for maintaining the assets and therefore know how they can be operated. Therefore, it is highly unlikely that a combined system operator and transmission planner and investor would have access to superior information and make better decisions.

4.2 Efficiency of standards

Criterion achieved through:

- Setting standards periodically on an economic cost benefit basis and expressing them deterministically to facilitate forward planning, transparency and accountability
  - Standards setting would ensure that uncertainty and high impact, low probability events are given due consideration
- Standards to be set by a body independent of the NSP with effective input from consumers and other stakeholders
- Full cost benefit analysis in certain circumstances at the time of investment decision making to identify whether there is a case for projects to be deferred or advanced compared to the default standard

At the outset, it is important to emphasise that the issue of who applies a reliability standard is, arguably, separate to the issue of what that standard is. Grid Australia is concerned that the Commission appears to have implied that an economically derived standard must be applied by AEMO.

Profit motivated TNSPs are entirely capable of applying economically derived standards. Indeed, such standards are already applied by profit motivated network businesses in the NEM, including at the transmission level where Transend applies a form of probabilistic planning for its network.

As correctly identified by the Commission, the efficiency of a planning standard depends on the extent to which there is a proper recognition of the trade-off between the costs and benefits of action with the costs and benefits of inaction. The cost of action here is the societal cost of any solution to an identified need. The cost of inaction is the loss of consumer value from an increased risk of power outages where a project does not proceed.

The AEMC's recommended approach to planning standards, with some enhancements identified by Grid Australia, equates to using a probabilistic assessment to determine the need for reliability investment. However, the enhanced AEMC approach is superior in a number of ways. Importantly, it delivers necessary transparency and accountability on decision making.

4.2.1 Economically robust and flexible investment outcomes

Grid Australia's proposed approach to planning standards (which enhances the AEMC's recommended approach) is set out in the attachment Economic Framework for Transmission Reliability and is illustrated in Figure 5.

The objective of the proposed approach is to transparently balance the value of customer reliability against costs.

Grid Australia has engaged with the Australian Energy Market Operator (AEMO) in the development of this improved national approach, which represents a change to the way the current planning arrangements operate in each NEM jurisdiction, including Victoria and South Australia.

Figure 5a: Application of the enhanced AEMC model proposed economic planning standard

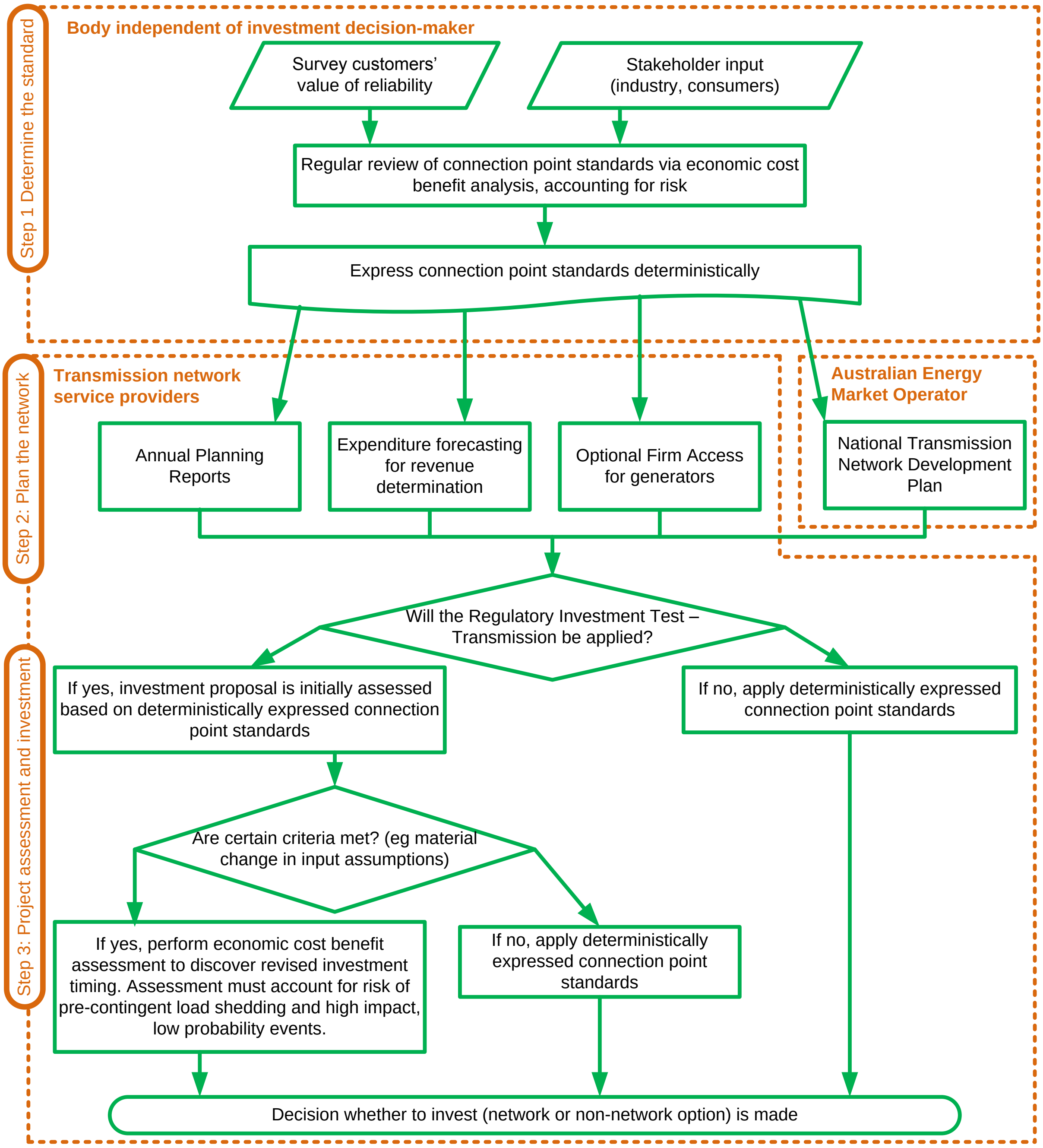
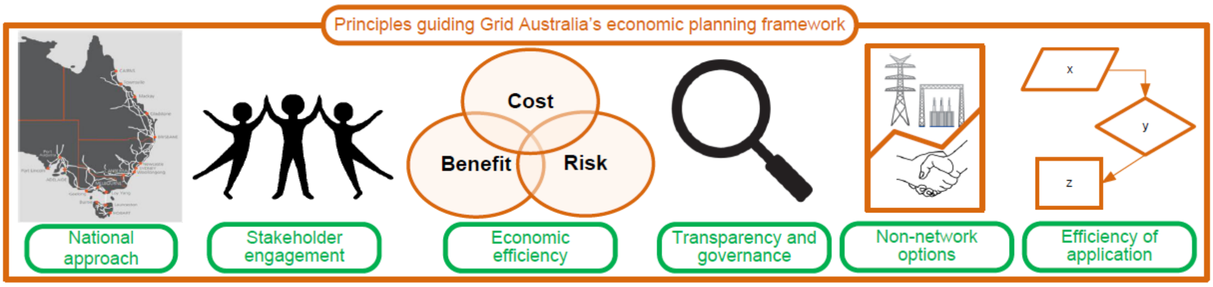


Figure 5b: Principles guiding Grid Australia's proposed economic planning standard



The Commission's main concern regarding economically derived but deterministically expressed standards appears to be that they may not be sufficiently flexible to accommodate changes in the nature of costs and benefits that underlie them.

Grid Australia's proposed approach addresses this perceived shortcoming. In this approach the standard for each transmission connection point is reviewed regularly (say every 5 years) on an economic cost benefit basis and expressed deterministically. The review should consider the economic cost benefit of increasing, maintaining and reducing the standard at each connection point.

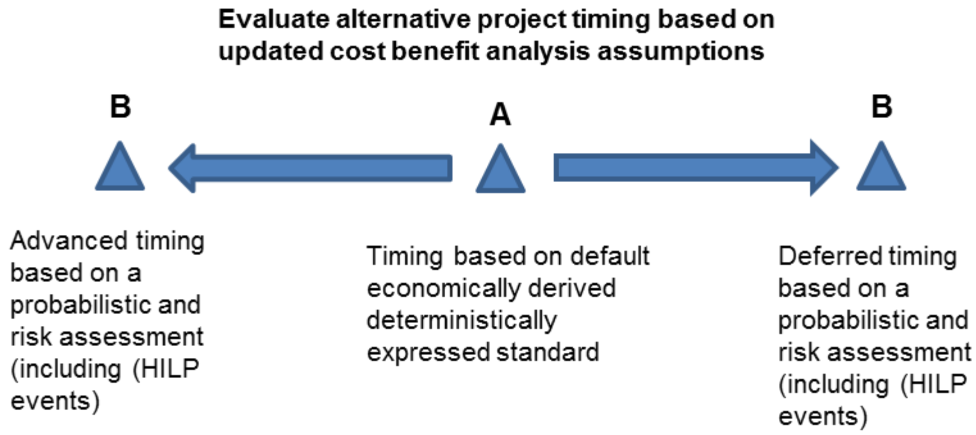
The review would be conducted by a body appointed by Governments that is independent of who applies the standard following a transparent process that facilitates effective input from consumer representatives and other stakeholders. This body would similarly be responsible for developing the methodology for undertaking economic cost benefit (probabilistic) assessments and associated assumptions.

The default deterministically expressed standards would be used for forward planning of transmission networks (e.g. for Annual Planning Reports) and for developing ex-ante expenditure forecasts.

At the time of the investment decision, the TNSP would as part of the RIT-T process apply the deterministically expressed standard determined in step 1 to identify the most cost effective network or non-network solution (given that this standard has already been determined using a cost benefit (probabilistic) assessment).

However, if certain criteria are met (e.g. when an investment option may be disproportionate or there has been a material change in input assumptions from the analysis conducted in step 1) an economic cost benefit (probabilistic) assessment would be undertaken by the TNSP at the time of the investment decision. This step would also take account of the risk of pre-contingent load shedding and high impact, low probability events that warrant consideration in a particular case to ensure that consumers are not exposed to excessive risk.

This would mean that an economically derived deterministic standard is used as a guide for the purpose of planning and to provide transparency and accountability while actual investments will be based on the economic case that prevails at the time the investment is considered (including retesting the timing of a proposed investment using a cost benefit (probabilistic) assessment when warranted). As demonstrated in the diagram below, analysis at this stage may defer or advance the required timing of a project.



Introducing flexibility into the application of deterministic planning standards means that the efficiency of investments will be no worse than for probabilistic planning, and potentially superior given planning would be based on a more robust assessment of the costs and benefits of reliable supply in the first instance.

Further, as discussed in more in section 4.5, there are considerable advantages that result from the significant increase in transparency and accountability that is provided from a deterministic expression of standards.

4.3 Minimising administrative and compliance burdens

Criterion achieved through:

- Independently set planning standards set on a periodic basis
- Investment decision making undertaken by TNSPs based on an ex-ante revenue cap supplemented by a contingent projects mechanism

Grid Australia agrees with the Commission that administrative and compliance burdens are minimised through:[17]

- Independently set reliability standards, and
- A process for setting standards that is as efficient as possible in terms of cost, timeliness and responsiveness.

[17] Productivity Commission, *Electricity Network Regulatory Frameworks, Draft Report,* October 2012, p.519.

As acknowledged by the Commission[18], in the context of planning standards these costs are best minimised through independently derived, and periodically set, standards.

It is important, however, that full regard is also given to the administrative and compliance benefits associated with retaining the transmission planning and investment decision-making functions within TNSPs. Delays and administrative costs that might be expected to result should AEMO take over the augmentation planning and investment function nationally include:

- Potential delays and costs associated with reaching agreement on a revenue allowance for each individual project
- Costs and delays for connection applicants in having to reach agreements with multiple parties
- Costs to connection applicants that would arise due to the inability for AEMO to make commercial and flexible decisions for which it is not accountable, and
- An inability for AEMO to make critical decisions in a timely manner given its dependency on TNSPs and other stakeholders for information.

Grid Australia considers the administrative cost advantages of TNSPs having responsibility for planning are material and streamlining of processes is an important factor in comparing options.

Notably, the issue of transaction costs in the efficiency of decision making is not new. Ronald H Coase's paper on the theory of firms and transaction costs (which contributed to his Nobel Prize in Economics in 1991) centres on the efficiency of a single firm undertaking many transactions relative to contracting for each transaction separately. Coase's work suggests that individual firms are more efficient in many circumstances as they can save a number of transaction costs involved in contracting out transactions.[19]

With respect to making timing and geographical decisions on augmenting transmission networks, Coase's ideas on transaction costs and the nature of firms are relevant. For instance there are certain search costs that AEMO would not necessarily be privy to, but transmission businesses would be such as construction, operation and maintenance costs of transmission networks. For this reason, AEMO would have to consult with the transmission businesses to obtain the information, therefore creating time and material costs that the transmission businesses could avoid.

[18] Productivity Commission, *Electricity Network Regulatory Frameworks, Draft Report,* October 2012, p.512.

[19] R.H. Coase, 'The nature of the firm', *Economica*, New Series, 4 (16), 1937, p390

4.4 Taking into account NEM-wide effects

Criterion achieved through:

- A National Transmission Planner taking a strategic long-term view of network investment integrated with regional plans developed by TNSPs
- Implementing the AEMC's Transmission Frameworks Review recommendations related to transparency, accountability and inter-regional investment, specifically through:
  - AEMO reviewing draft TNSP planning and investment test reports
  - AEMO providing demand forecasts for use in transmission planning
  - AEMO undertaking an expert independent advisory role (which can be utilised at the time of revenue determinations)
  - AEMO assuming the Last Resort Planning Power with an enforceable power to compel investments
  - NEM-wide transmission pricing
  - New requirements for consultation between TNSPs when preparing annual planning reports
  - New revenue arrangements for cross-regional investment to remove any potential disincentive for projects to commence

A key justification of the Commission's for considering assigning AEMO the role of planning and investment decision making for the shared transmission network appears to be based on the view that it is better able to take account of NEM-wide effects in planning. These effects are described as the ability to use a combination of regional and inter-regional solutions to address a need as well as the ability to manage the risks of cascading failures across jurisdictions.

Grid Australia, however, considers that for those NEM-wide effects that are relevant to the planning time horizon the AEMC's recommendations, as identified in the box above, will facilitate the proper consideration of relevant NEM-wide matters in planning.

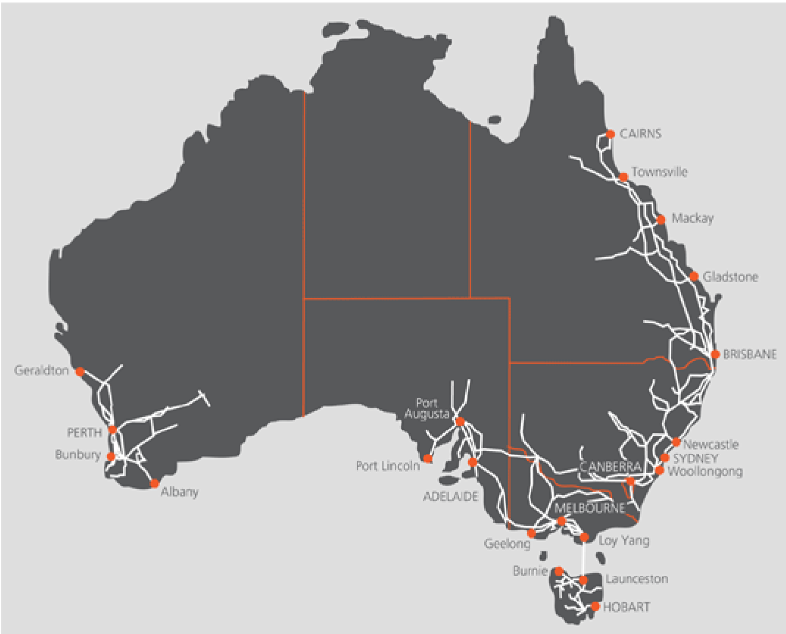
<u>A proportional response to ensuring NEM-wide planning</u>

While planning at a national level is clearly important, it is also necessary to recognise that the primary role of transmission networks is the delivery of electricity from generation sources (which itself is a function of fuel sources) to the distribution networks that are located where customers live and work.[20] TNSPs do not have a direct influence over the location choices of either of these parties.

Rather than state boundaries or the geographic responsibilities of TNSPs, it is evident that the location of generators and customers is the major driver behind the current configuration of the network.

The map below illustrates this point showing that transmission lines run from generators at their fuel source out to major load centres. It is also reflected in the fact that a major driver for the AEMC's TFR was the view that a change in the location of generation, due to an increase in renewable energy generators, would lead to a need for new investment on the transmission network. A primary concern in this regard was how to provide signals to generators regarding the costs they might cause for the electricity network.

Figure 6: High Voltage Transmission Line in Australia[21]



The view that state boundaries have not led to an inefficient configuration of the network is supported by the Commission's own finding that there has not been under-investment in interconnectors. Therefore, while it is necessary for a national strategic perspective to transmission planning to be taken, it is important not to overweight the impact this has on the actual and future configuration of the network.

20 Noting, as indicated above, that there is the potential for this interaction to become increasingly complex as smart grid and embedded generation technologies become more advanced.

21 Available at: http://www.gridaustralia.com.au/index.php?option=com_content&view=article&id=74&Itemid=160

Further, the evidence suggests that where inter-regional solutions are suitable for addressing local needs TNSPs have been successful in identifying these and implementing them. Some examples include:

- Joint planning between AEMO (in its role as Victorian jurisdictional planner) and ElectraNet on options to reinforce transmission capacity for the Riverland in South Australia. This joint planning has investigated less costly solutions for meeting the Riverland reliability requirement that take into account requirements in the Riverland in South Australia and Western Victoria.

- Joint planning between TransGrid, Powerlink, Essential Energy and Energex over the past decade has ensured timely and cost effective augmentation has progressed in southern Queensland and in northern New South Wales. This has been especially important in optimising the sequencing of the timings of the Goal Coast transmission augmentation in Queensland and the Lismore transmission augmentation in New South Wales, taking into account the transfer capacity through the DirectLink HVDC link, to ensure mandated reliability levels are met within each area.

The effectiveness of the current approach to planning is further reinforced by the fact that the AEMC has found there are no projects that should be progressing that are not under its Last Resort Planning Power.

<u>Long-term national strategic plans translated into near-term regional plans</u>

The AEMC's proposed enhancements will strengthen the level of oversight on TNSPs' planning functions as well as removing any disincentive inter-regional TNSPs may have for funding a project to benefit another region.

Under these arrangements AEMO's advice would have significant influence over the actions of TNSPs. In the first instance AEMO's advice would be provided publically and transparently. Therefore, there would be strong public pressure and moral suasion on TNSPs to follow its advice, or conversely to provide good reasons for choosing something different.

Further, under the new Rules TNSPs would expect there to be a high chance of an ex-post disallowance of expenditure if the investment was not fully justified or did not conduct the RIT-T in a robust manner.[22] Importantly, however, TNSPs have a much better understanding of their networks, and service performance obligations rest with them. Given these facts it is essential that the option to vary from the recommendations of AEMO remain with TNSPs, where there is strong evidence that AEMO has not chosen the most efficient option and where there is a critical need.

[22] The Rules are to include the power for the AER to assess the prudency of past expenditure in circumstances where actual expenditure exceeds forecast expenditure over the previous five year period.

It is also important to note in this respect that the RIT-T is a highly prescribed test that is conducted with oversight by interested stakeholders and the AER. This oversight is also strengthened through the AEMC's proposals. While the current formulation of the test is still relatively new, there is no reason to suggest that this test will not be applied as prescribed and in good faith[23]. .

In addition, the AER also has oversight over the application of the RIT-T and would be expected to have regard to its application for revenue setting purposes.

4.5 Transparency, accountability and auditing compliance

Criterion achieved through:

- Planning standards expressed deterministically so that customers and market participants are better able to predict potential network investments
- Ensuring appropriate oversight of TNSP investment decisions by AEMO (including as the Last Resort Planner), the AER and other stakeholders such as consumers and generators
- The transmission businesses having control of all the elements related to transmission service outcomes e.g. augmentation investment, replacement investment, asset life extension projects, operation and maintenance. This makes it easier to hold the TNSP accountable for service and cost outcomes resulting from the combination and co-ordination of these factors.

4.5.1 Application to planning standards

Grid Australia agrees with the Commission that the transparency and accountability of outcomes is considerably easier with deterministically expressed planning standards. However, Grid Australia is concerned that the Commission may have discounted the importance that this has on the success of the framework overall.

The key benefits from the transparent expression of standards include:

- It better facilitates forward planning by providing an objective measure of when an investment might be required. This in turn facilitates better planning by those that interact with the transmission network such as generators, large customers and distributors.
- It better facilitates stakeholder engagement on annual plans and the application of the RIT-T

[23] Indeed, Grid Australia has published Guidelines on how it intends to apply the RIT-T and consulted with both the AER and AEMO prior to doing so. See: http://www.gridaustralia.com.au/index.php?option=com_content&view=category&layout=blog&id=129&Itemid=246

- It better ensures that the party that applies the standard is less able to impose uneconomic risk or cost onto customers (noting that this incentive exists irrespective of who applies the standard)

- It makes the task of economic regulation more straightforward as it is more straightforward to prepare and assess capital expenditure forecasts (although this is a marginal issue and is feasible under either approach)

The importance of providing transparency on the planning standard for transmission is reflected in the fact that the transparent expression of transmission planning standards is overwhelmingly the dominant approach taken by major economies worldwide.[24]

4.5.2 Application to national planning

Transparency and accountability are not just important to planning standards; they are also relevant to who applies the standard and how it is applied.

Transparency and accountability of decision making is substantially increased in a circumstance where TNSPs have responsibility for network planning. This is because oversight can be provided by AEMO through its NTP role, the AER as the economic regulator, and the AEMC through its (present) Last Resort Planning Power.

The new rules for economic regulation further strengthen the oversight and scrutiny on TNSP investment decisions. and future proposals. This includes, through the requirement for the AER to conduct annual efficiency reviews to compare the performance of all TNSPs and the need to demonstrate in revenue proposals the extent the capital expenditure forecast includes expenditure to address the concerns of electricity consumers.

Notably, the importance of sufficient oversight and accountability was one of the key reasons that the AEMC has recommended Victoria move to SP AusNet taking over responsibility for network planning in that jurisdiction. In considering the proposed expanded roles for the NTP and AEMO's current role the AEMC stated the following:[25]

> *"Each of these additional roles implies a national entity providing oversight and advice on the analysis and conclusions of jurisdictional TNSPs that is independent of those state-based planning processes. The different institutions involved in planning ensure that there is an appropriate tension and check on the planning role within the market. While this is consistent with the arrangements in most of the jurisdictions in the NEM, an*

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24 KEMA, *International Review of Transmission Reliability Standards, Summary Report prepared for the Australian Energy Market Commission Reliability Panel,* 27 May 2008.

25 AEMC, *Transmission Frameworks Review, Second Interim Report*, 15 August 2012, pp.70-71.

inconsistency would arise in applying the arrangements in Victoria. This is because AEMO would essentially be providing a check and balance on its own work.

There are a number of options for resolving this inconsistency. For example, a new Victorian planning body could be established and assigned responsibility for jurisdictional planning in Victoria. However, the Commission considers that providing a consistent approach across the NEM is preferable, with the institutional arrangements in Victoria being aligned with those that apply elsewhere. This would imply assigning responsibility for jurisdictional planning to SP AusNet."

Conversely, under the proposal for AEMO to undertake national planning much of the planning and investment decisions will occur outside of the revenue determination process. This has a number of implications:

- Costs can be placed onto customers with little scrutiny of their efficiency as in most cases approval from AEMO, an organisation with limited experience reviewing expenditure proposals other than to compare tenders or in building transmission assets, will be sufficient for costs to be passed through to consumers.
- The absence of an integrated revenue proposal that relates to asset replacement, augmentation and operating and maintenance expenditure means that third parties, and customers in particular, will be more limited in their capacity to assess an investment program in its entirety and as such compare and contrast the trade-offs that can be made by service providers.
- There is no ability for the AER to identify the total price that customers will pay at the time of a determination absent the costs that would be imposed by AEMO's subsequent planning decisions. This limits the ability for customers and other stakeholders to benchmark and compare proposed prices across jurisdictions.
- The fact that there would be only one body undertaking augmentation planning and investment means that there would no longer be any scope for the 'competition by comparison' that can occur between regional TNSPs.

The split of responsibilities created through installing AEMO as the national planner would have further implications with respect to the obligations for service performance. Under a national model where AEMO is the national planner accountability for meeting performance standards across the system will be dispersed. Meeting transmission service requirements requires trade-offs to be made and effective coordination between network augmentation, renewal and operating and maintenance expenditure

However, under the proposed framework responsibility for delivering on each of these aspects will reside with different parties. This fact, combined with the absence of financial incentives on AEMO, considerably increases the risk of an inefficient coordination of investment decision making.

It is also relevant to note that there is little evidence to suggest that the AER has the desire, or the capacity, to properly oversee AEMO compliance. Indeed, there has not been a single compliance review of AEMO by the AER in the past two and half years. The implication of this lack of oversight of AEMO's actions is that costs can be imposed on customers with little or no scrutiny of their efficiency.

4.6 Compatibility with wider market design arrangements

Any model for transmission planning arrangements needs to be able to integrate well with and support the wider market design. Key aspects of the wider market design in this respect include:

- Service provision for generators operating in the wholesale market
- Connection arrangements for generators and large load customers,
- The regulation of prescribed network revenues, and
- Interactions with localised distribution networks.

Figures 7a and 7b above show the respective interactions with the first three of these aspects of the wider market design for each of the proposed models. Not only does the Productivity Commission model result in much more complex interactions but in some respects required interaction is absent. For example, AEMO's investment function would be 'out of reach' from the incentive regimes associated with the regulation of prescribed network services.

Furthermore, under the current framework service delivery for transmission networks is predominately focused towards customer reliability. However, the AEMC's Optional Firm Access Model, which is supported by the Commission, would substantially redress the imbalance and increase the focus of services provided to generators. This model would allow generators to negotiate, and pay for, a level of firm access on transmission networks. In doing so it substantially broadens the accountability of transmission businesses for transmission service delivery, including through extending the coverage of financial incentives for service.

Grid Australia considers that the success of the Optional Firm Access model is largely predicated on financially motivated TNSPs being able to make trade-offs about how firm access is to be efficiently delivered. This includes being able to make trade-offs between operating and capital expenditure in order to meet firm access requirements and to maximise network capability. As such, giving planning responsibility to AEMO severely limits the scope for economic and innovative solutions to meeting firm access to be identified given its limited capacity to assess and share risks.

Figure 7a: Interaction of enhanced AEMC model with NEM-wide arrangements

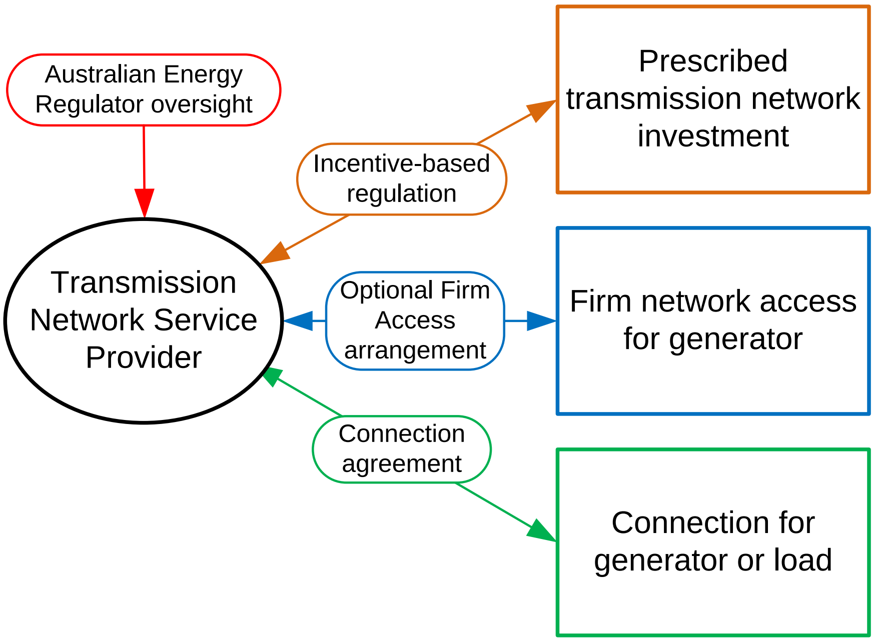
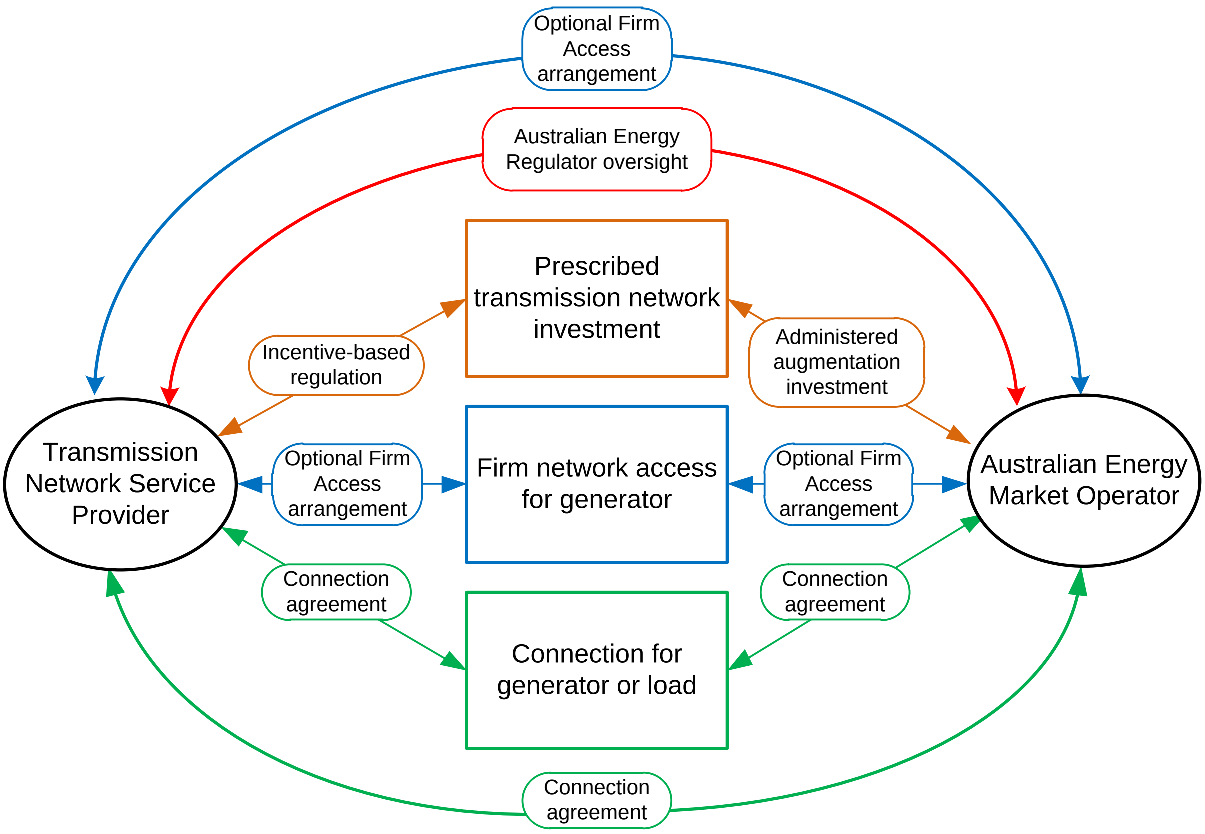


Figure 7b: Interaction of Productivity Commission's proposed model with NEM-wide arrangements



In the context of network connections, separating the responsibility for network planning with service delivery has proven in Victoria to lead to less desirable outcomes. In Victoria connecting parties need to form an agreement with AEMO for any works that may be necessary on the shared network to facilitate their connection and also with SP AusNet. This framework creates additional commercial complexity for connecting parties due to the need to deal with two parties. In addition, it creates uncertainty and dispute regarding the allocation of risk and liability between the parties. The ability to overcome these issues in Victoria is hampered given that AEMO's not-for-profit status means it has no flexibility to deal with commercial matters. Delay in progressing new connections and additional cost results from these complexities.

As demonstrated in section 4.4. a significant part of a transmission business' functions is to undertake joint planning with distribution network service providers. This requires planners to have a good understanding over local issues. It also requires that TNSPs be agile to the needs of distributors, given in particular, that ultimately the majority of customers are connected to distribution networks.

5 Apparent errors impacting on the assessment of alternative frameworks

5.1 The Victorian arrangements have not delivered more efficient investment

The Commission has referred to the perceived success of the Victorian planning framework to make the case for its recommended approach to transmission planning and investment.[26]

However, as Grid Australia has identified in previous submissions to this Inquiry, this perception ignores the historical development of the Victorian transmission network and its impact on current outcomes. Considerable network investment was undertaken in Victoria prior to energy market reform, and this investment has had a high correlation to growth corridors. This would appear to allow relatively little recent investment, compared to other transmission networks.

In Grid Australia's previous submission to this Inquiry, an Evans & Peck report was attached to examine AEMO's claim that the Victorian planning framework produced preferable outcomes.

Attached to this submission, Grid Australia provides a second Evans & Peck report which responds to the recently-published CME paper for the Energy Users Association of Australia. The Evans & Peck report considers whether legacy

[26] Productivity Commission, *Electricity Network Regulatory Frameworks, Draft Report,* October 2012, pp.502-503..

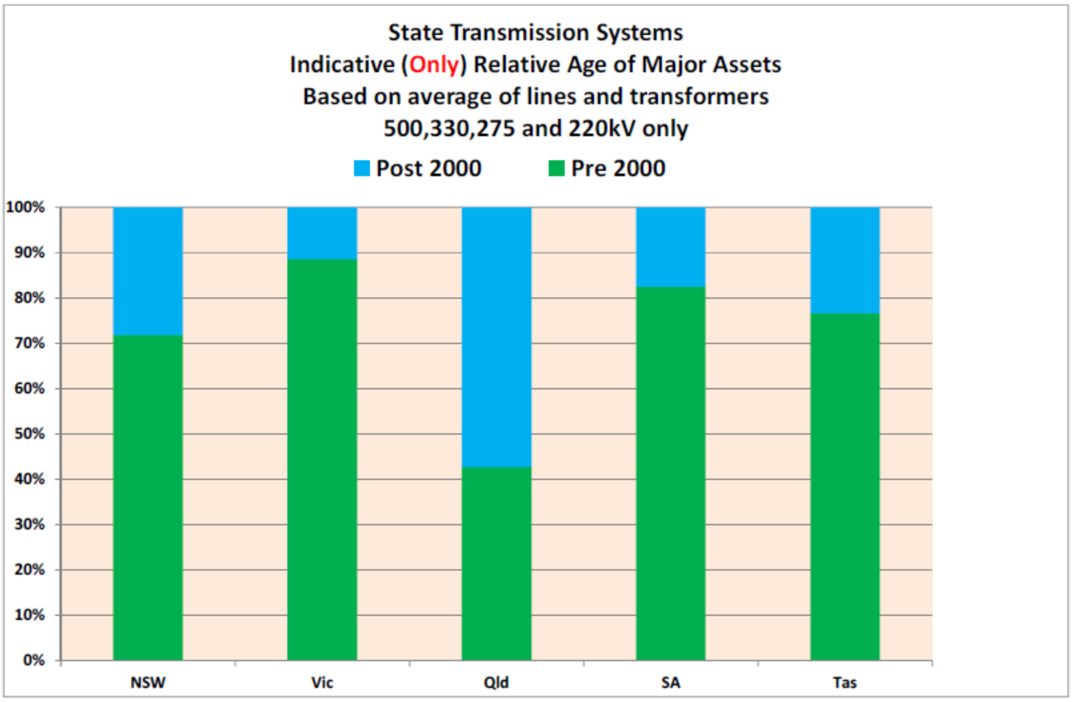
investment and its proximity to growth corridors had an impact on present outcomes in Victoria. Its finding is that the Victorian network has been able to absorb substantially more growth in demand than has been the case for other jurisdictions. In turn, this has meant that less network augmentation has been necessary in Victoria over the past decade.[27]

> *"In this report, we have shown that over the last 11 years, the Victorian transmission network has been able to absorb a 35% growth in demand and a 22% growth in customers without any material increase in line length. Evans & Peck is of the view that this demonstrates that the transmission lines at least had spare capacity. Whether they could be considered to have been "over built" or "gold plated" needs to be considered on the basis of the information available at the time of investment, not in hindsight, but the fact remains they had spare capacity. On the other hand TNSP's in Qld, NSW and Tasmania have found it necessary to added transmission lines to cope with growth in demand and customers."*

The Evans & Peck graph shown in Figure 8 provides a broad indication of the ages of the various transmission networks in the NEM, showing that the Victorian network is relatively "old" while the Queensland network is relatively "young". The graph in Figure 9 provides insight into the meaning of this age discrepancy – put simply, at the start of the 11-year period examined, Victoria had a high installed transformer capacity to load ratio, compared to other networks. This was not the case at the end of the period.

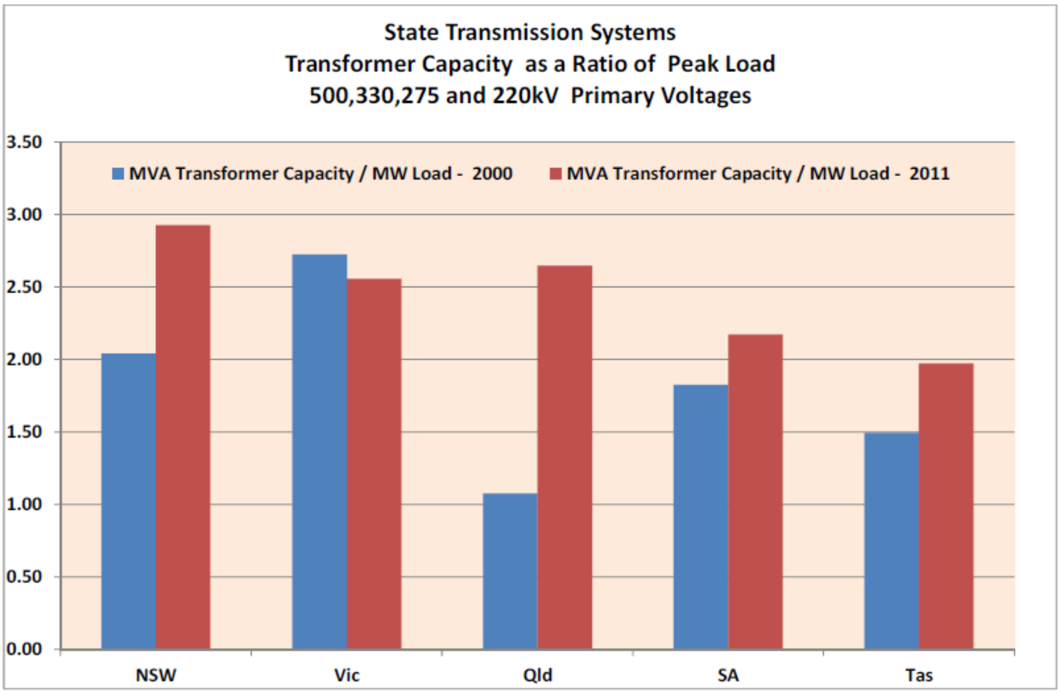
[27] Evans & Peck, *Response to CME Report Prepared for Energy Users Association of Australia – A comparison of outcomes delivered by electricity transmission network service providers in the National Electricity Market,* November 2012, p. 9.

Figure 8 - Evans & Peck comparison of state transmission systems' indicative relative age of major assets



Source: Evans & Peck, 'Response to CME report', Figure 3.2, page 8, November 2012.

Figure 9 - Evans & Peck comparison of state transmission networks' variance in installed transformer capacity per peak load between 2000 and 2011.



Source: Evans & Peck, 'Response to CME report', Figure 2.4, page 5, November 2012

When considering the facts of the case in Victoria it is not possible to conclude that there is a direct correlation between its network planning and investment framework and observed outcomes. Instead, the evidence reveals that this framework is yet to be seriously tested in any meaningful way.

5.2 Difficulties in allocating risk under the current Victorian transmission arrangements

The Commission makes the following statement on risk and accountability under the current Victorian transmission arrangements:

> *"SP AusNet is responsible for ensuring that reliability in the transmission network in Victoria is maintained, subject to planning decisions made by AEMO. If a planning decision were found to be the cause of significant damage to a third party, AEMO would be liable if it had been negligent in carrying out its statutory planning functions."*

However, in its submission to the Commission, SP AusNet questions this claim at length. Among other matters SP AusNet notes that:

1. Actual experience suggests that it is extremely difficult to assign risk to the parties in rigorous contracts consistent with the intended allocation of responsibilities. This is because the separation effectively makes two separate entities responsible for the provision of transmission services, which is generally regarded as highly integrated.

2. That the incentives on the shared transmission planner in Victoria, a 'not for profit' body, are poor, and disproportionate risk is likely to be borne by the network operator.

3. The model preferred by the Commission proposes that the AER would monitor AEMO's implementation of the planning process to ensure it is operating to good practice. This would be problematic for the AER due to the absence of comparable firms carrying out these functions.

4. Neither the regulation or compliance arms of the AER currently have sufficient resource capability to carry out this role.

On this latter point Grid Australia is unaware of any reviews carried out by the AER of AEMO's compliance with the Rules in at least the last two years.

5.3 Implementation, transitional issues and the case for change

The Commission has sought to quantify the benefits of its recommended approach to transmission planning and also some of the perceived inherent costs of the existing approach, including that:

- Across the NEM, $2-3 billion of transmission investment can be avoided over the next five year period by moving to a new reliability framework (relative to a total asset value for transmission of around $14.2 billion)

- $11 billion in system capacity is used for only 100 hours per year.

- One cycle of revenue determinations costs $330 million

Grid Australia, however, is concerned at how robust these benefits might be, and therefore, whether they are misleading in the choice between alternative options.

In the first instance, it is relevant to note that the Commission appears to have predominately estimated the benefits associated with a move from the current planning standards, with is acknowledged deficiencies, to a probabilistic approach. This, however, does not reflect the real status quo where the AEMC and TNSPs each agree that planning standards should be economically derived (and this has been agreed by Governments). As such, future investments would not be expected to be based on the current standards.

It is also not clear from the Commission's discussion what other relevant assumptions it has used in deriving these benefits. For example:

- Where has the Commission factored in the investment response to falling demand – has it included the deferrals that would have occurred anyway under even the existing deterministic standards?

- Has the Commission factored in the loss of value to customers from the lower level of reliability that comes from deferring investment (i.e. even if a project was considered to cost more than the resulting reliability benefits, it does not mean that it provides zero benefit)?

The implications of what appears to be the approach taken to assessing potential benefits is that the size of the problem that needs to be addressed is overstated, and therefore, so to is the extent of the proposed solution.

Grid Australia recommends that the Commission reconsider its assessment of the proposed benefits of alternative models in conjunction with a more fulsome assessment of the costs of transition.

5.4 International practice does not support the Productivity Commission's proposed model

The Commission has sought guidance from international approaches to transmission planning, particularly North America, to support its recommended approach to transmission planning and investment.

However, this has not been a holistic assessment of these frameworks. As such, key differences have not been appreciated implying that the North American approach to transmission planning is not directly comparable, or applicable, to the NEM.

As indicated above, Grid Australia requested NERA to undertake a review of the North American transmission planning framework to identify relevant lessons for the Australian context. NERA found that key differences between the NEM and North America drove a separation between transmission planning and investment decision making and network ownership. The key differences identified by NERA include:

- There is a high degree of common ownership in North America between transmission and other electricity sector activities, including generation and electricity retailing.
- Transmission planning arrangements in North America continue to draw a distinction between 'reliability' and 'economic' investments.
- There is often a formal role for stakeholders/ members in both the governance and planning processes of the system operators and Regional Transmission Organisations.
- North America predominately applies a cost-to-serve approach to economic regulation which does not present the same incentive to minimise cost as the NEM regulatory approach.

Once these key differences are taken into consideration it is evident why North American jurisdictions might have taken a different approach to that taken in the NEM. Consequently, it is also evident why caution should be taken in attempting to apply the North American approach in support of a change to transmission planning and investment in the NEM.

Application of Competitive Procurement in North America

NERA's report also focuses specifically on the application of competitive procurement in North America. NERA finds that the adoption of competitive procurement arrangements for transmission continues to largely be in the formative stages in North America. As a consequence, there is currently little available outturn evidence on the effectiveness of these arrangements.

- California introduced competitive procurement provisions in 2010, for investments identified as 'economic' projects as distinct from reliability investments. To date these arrangements remain untested.
- Alberta is currently in the process of introducing competitive procurement provisions, which will apply only to transmission investments designated as 'critical transmission infrastructure'.

- FERC Order 1000 has resulted in an increase in the number of ISO/RTOs proposing to introduce competitive procurement arrangements. This includes Midwest ISO (MISO), ISO-New England (ISO-NE, for public policy investments) and Southwest Power Pool (SPP). However these revised provisions are not yet in place, and will first require FERC approval,

The exception is Texas, where competitive procurement was adopted by the Public Utilities Commission in 2008 for transmission extensions to designated Competitive Renewable Energy Zones. NERA has identified, however, that the cost of these extensions has been substantially higher than initially anticipated (for a number of reasons).

6 Conclusion and recommendations

Overall, the draft Productivity Commission report makes a valuable contribution to the assessment and policy debate on how best to achieve more efficient provision of electricity network services.

However, in relation to transmission planning arrangements, the Commission has failed to show why its proposals are superior to those developed by the Australian Energy Markets Commission in its draft Transmission Frameworks Review report.

The only quantitative data provided by the Commission is to compare the benefits of moving from a mandated deterministic set of transmission planning standards to a probabilistic framework for planning and investment in shared transmission network augmentations. Not only is this not relevant to the frameworks being compared, but it casts no light on who should carry out shared transmission network investment and planning. In relation to the latter, , important assessment criteria appear to have been overlooked. These include ensuring clarity of accountability for transmission service outcomes, and integration of any proposed transmission framework with wider market design considerations.

Once these additional criteria are considered qualitative assessments of different transmission planning and investment arrangements strongly suggest that the AEMC's current proposals, with some modification, best serve the National Electricity Objective i.e. are more likely to produce economically efficient outcomes. At the very least the costs of a major restructure of investment responsibilities in the transmission sector, as proposed by the Productivity Commission in its draft report are not justified.

Most importantly having profit motivated transmission network service providers carry out shared network planning and investment opens up the 'levers' available to regulators to include commercial incentives, in addition to administrative requirements such as Rules and licensing compliance. This also enhances the potential for driving more efficient integration of augmentation, replacement, refurbishment, and maintenance decisions by the transmission asset owners.

Having AEMO carry out shared network planning and investment limits performance controls to administrative arrangements only and significantly limits the scope for efficient integration of this function with other transmission asset owner functions.

Furthermore, the evidence provided by parties, such as Carbon Market Economics and AEMO itself, in support of the current Victorian transmission arrangements is demonstrably flawed. Important exogenous factors have been ignored and/ or the results are inconclusive when analysed more thoroughly.

Accordingly, it recommended that the Productivity Commission reassess its position on these matters and amend its final report to reflect the outcomes of that reassessment.

grid australia
BACKBONE OF THE NEM

Economic framework for transmission reliability

Grid Australia is proposing a new planning standard to transparently balance the value of customer reliability against costs and has engaged with the Australian Energy Market Operator (AEMO) in the development of this initiative.

An improved national approach is needed, which represents a change to the way the current planning arrangements operate in each NEM jurisdiction, including Victoria and South Australia.

Proposed Principles

The proposed approach is based on the following principles:

- A national approach – a transmission reliability planning standard should be developed that can be applied consistently across the NEM.
- Consumer and stakeholder engagement – the proposed approach should incorporate how consumers and other stakeholders are involved in the decision making process for setting reliability standards and appropriately balancing the value of customer reliability against cost[1].
- Economic efficiency – the standards should be based on a cost benefit analysis that explicitly takes into account the value customers place on reliability of supply (including the additional value customers place on certainty of outcomes)[2].
- Non-network solutions – the standards should facilitate equal consideration of network and non-network solutions (e.g. demand side response or generation network support) for maintaining transmission reliability.
- Transparency and governance – reliability standards should be set by a body that is independent of who applies the standards following a transparent process that facilitates effective input from consumers and other stakeholders. The standards should also promote transparency in forward planning of transmission networks and in setting efficient ex-ante expenditure allowances[3].
- Efficiency of application – the standards should be practically workable and promote network planning and investment decision making that is proportionate to the network or non-network solution options being considered.

[1] It is important that the broad interests of consumers are represented in the process and not just those of special interest groups.

[2] Inherent in this principle is the need to appropriately account for the additional value customers place on certainty of outcomes and the uncertainties associated with the costs and benefits being evaluated.

[3] Different revenue regulation arrangements currently apply in Victoria which do not involve the setting of efficient ex-ante expenditure allowances.

Proposed Approach

The proposed approach to transmission reliability involves a three-step process as follows[4]:

Step 1

- The standard for each connection point is reviewed regularly (say every 5 years) on an economic cost benefit basis and expressed deterministically. The review should consider the economic cost benefit of increasing, maintaining and reducing the standard at each connection point.

- The review would be conducted by a body appointed by Governments that is independent of who applies the standard following a transparent process that facilitates effective input from consumer representatives and other stakeholders. This body would similarly be responsible for developing the methodology for undertaking economic cost benefit (probabilistic) assessments and associated assumptions.

Step 2

- The default deterministically expressed standards determined in step 1 would be used for forward planning of transmission networks (e.g. for Annual Planning Reports) and for developing ex-ante expenditure forecasts[5].

Step 3

- At the time of the investment decision, the TNSP would as part of the RIT-T process apply the deterministically expressed standard determined in step 1 to identify the most cost effective network or non-network solution (given that this standard has already been determined using a cost benefit (probabilistic) assessment).

- However, if certain criteria are met (e.g. when an investment option may be disproportionate or there has been a material change in input assumptions from the analysis conducted in step 1) an economic cost benefit (probabilistic) assessment would be undertaken by the TNSP at the time of the investment decision[6]. This step would also take account of the risk of pre-contingent load shedding and high impact, low probability events that warrant consideration in a particular case to ensure that consumers are not exposed to excessive risk[7].

Note that the required timing of a project may vary between the cost benefit analyses undertaken at step 2 compared to applying the default standard set at step 1 of the process. Such timing variations may occur where there have been material changes in input assumptions (e.g. the cost of a network or non-network option). Analysis at the second step of the process may defer or advance the required timing of a project (refer to diagram below).

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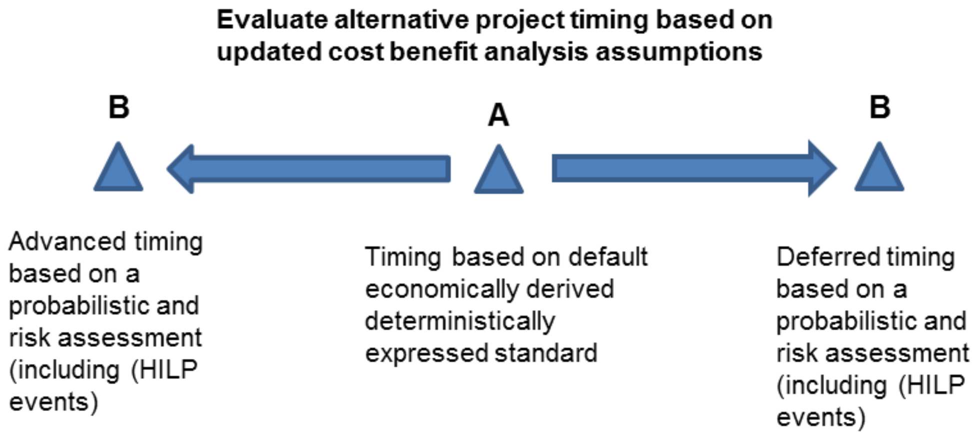
4 Note this is different in important respects from the approach current applied in Victoria, South Australia and other jurisdictions in the National Electricity Market.

5 Again different revenue regulation arrangements currently apply in Victoria which do not require the setting of efficient ex-ante expenditure allowances. Note also that at this step consideration of non-network options would be at concept level.

6 Suitable criteria to be developed to determine when the deterministically expressed standard can be relied upon and an economic cost benefit assessment or other additional analysis is not warranted at the time of the investment decision.

7 Note that the methodology for applying this risk assessment is not yet well developed in any of the current applications of reliability standards in the NEM.



30 November 2012

EVANS & PECK
think through the future

Grid Australia

Response to CME Report Prepared for Energy Users Association of Australia – A comparison of outcomes delivered by electricity transmission network service providers in the National Electricity Market

November 2012

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1 Background

In August 2012 Evans & Peck assisted GridAustralia develop a response to the Australian Energy Market Operator's (AEMO's) submission to the Productivity Commission's Public Inquiry on Electricity Network Regulation – Issues Paper. A central theme in AEMO's submission[1] is that the Victorian model, whereby AEMO plans, but does not own, the "shared" transmission network, provides superior outcomes in terms of utilisation, reliability and capital expenditure when compared to those states where planning is performed by the asset owner. AEMO's logic subsequently extended to the rationale that planning should be done centrally by an "independent" agency such as AEMO.

Subsequently, CME consulting has provided a report to the Energy Users Association of Australia titled "A comparison of outcomes delivered by electricity transmission network service providers in the National Electricity Market". CME concluded:

- *The provision of transmission network services in Victoria has been consistently better than in other states in respect of regulated revenues, the size of the regulated asset base, and the level of operating expenditure and capital expenditure. The most significant gap however is in respect of load-driven capex.*
- *Economies of scale (or more precisely higher through-put in the larger networks (in Victoria, NSW and QLD) may explain part of the gap with the networks in the smaller states (South Australia and Tasmania). But this does not explain why expenditure has risen so much in all states except Victoria[2].*

CME attributes these superior outcomes to two key factors – "**Ownership"** and "**Planning":**

- *The relative performance of transmission network service providers also seems to be drawn along ownership lines: transmission network service provision in Victoria is privatised and appears to have consistently delivered better outcomes than seems to be the case where governments own the network service providers[3].*
- *It might be concluded that the Victorian planning arrangements, relative to those in New South Wales and Queensland, have reduced the prospect that energy users are charged for expenditure that evidently has not been required. Governments in other states might be encouraged to have closer regard to the Victorian arrangements[4].*

In arriving at these conclusions, CME notes:

> *"This paper has not sought to explore exogenous factors (other than demand growth) that might explain the difference between Victoria and the TNSPs in other states. Some TNSPs have alluded to the legacy of historic investments in Victoria as explaining the*

[1] Electricity Network Regulation – AEMO's Response to the Productivity Commission Issues Paper – Version 2 – 21 May 2012
[2] CME P5
[3] CME P6
[4] CME P7

difference between the apparently better performance of SP Ausnet. We have not attempted to test this claim rigorously. However, prima facie, it seems implausible".[5]

A key observation of our earlier work related to the high correlation between growth corridors in Victoria, and the 500kV network, as demonstrated in Figure 1.1. To date we have not tested assumptions relating the capacity of that network. Given the veracity of CME's conclusions appear dependent on the dismissal of arguments relating to "exogenous factors" and "legacy investments" in particular, Evans & Peck has sought to examine the validity of this dismissal in more detail in this report.

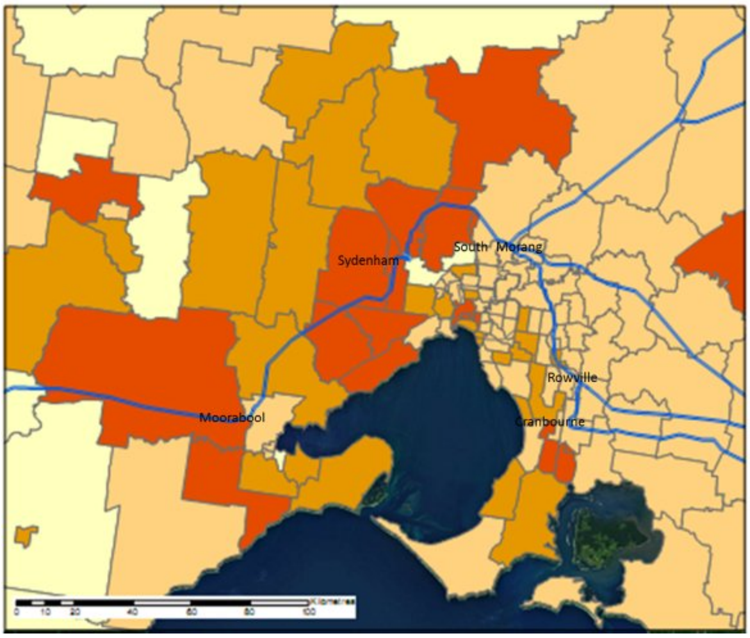

Figure 1.1– Population Growth and Transmission Infrastructure - Port Phillip

[5] CME P5

2 The Relationship between Growth and Capital Investment

Figure 2.1 shows key growth factors between 2000 and 2011. Customer growth values have been drawn from the ESAA publication "Electricity Australia 2001" and its 2011 equivalent. Demand growth factors have been developed by comparing the highest demand experienced on each system since July 2001, with the highest demand in the two years leading up to June 30, 2001. Whilst not weather corrected, this negates the impact of a decline in demand in the recent past. Evans & Peck is of the view that this treats TNSP's comparatively equally.

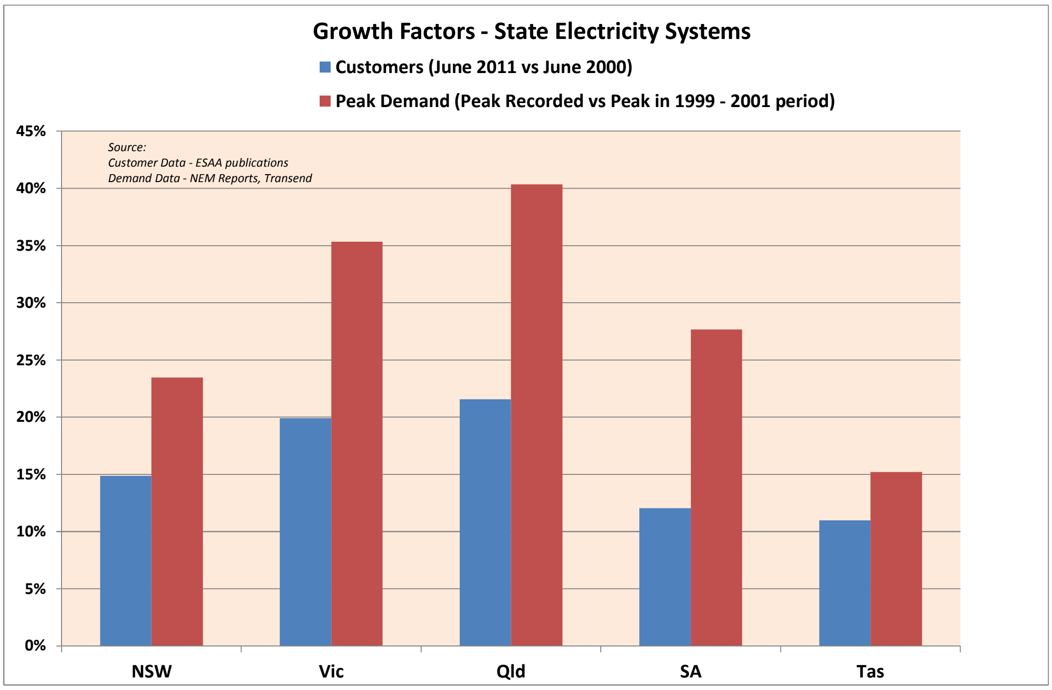

Figure 2.1 – Jurisdictional Growth in Demand and Customers

Queensland has incurred the highest demand growth at around 40%, followed by Victoria at just over 35%. In a similar vein, Queensland has had the highest growth in customers at 22%, followed by Victoria at 20%. At the highest level, there is no material difference between these two states. However, examination of the capital response shows marked differences.

Figure 2.2 shows the growth in transmission line (500, 330, 275 and 220kV) length over the 11 year period. The Victorian transmission system has coped with a 20% increase in customers, and a 35% increase in peak demand, while only expanding 1.7% in circuit length. At the other end of the spectrum, Powerlink's circuit length has increased 56% in accommodating a 22% increase in customers and a 40% increase in demand. During this period, the Queensland – NSW Interconnector was brought into service. It is difficult to argue that this has not had significant market benefits for the NEM in general, and Qld / NSW in particular. Quantification of externalities such as this has been largely ignored in the CME analysis.

In presenting Figure 2.2 we have approximated the impact of QNI on the growth in transmission system circuit length. At the beginning of the period, Queensland was an isolated system.

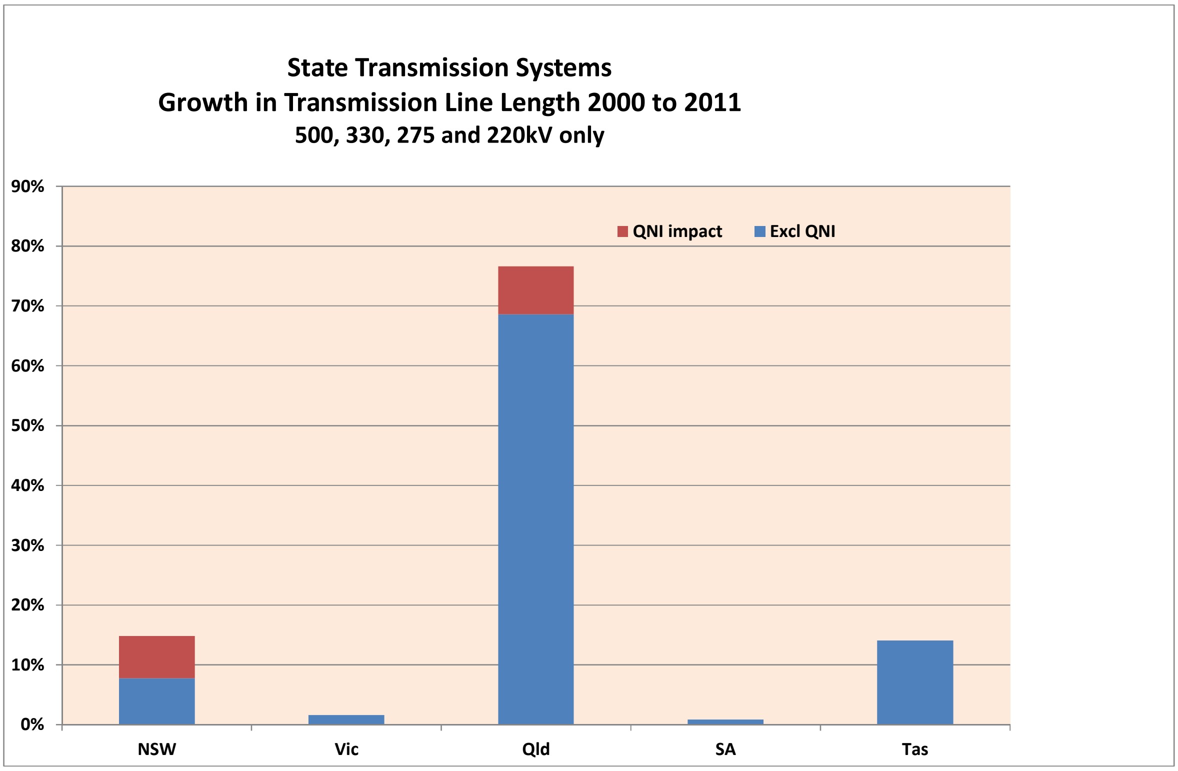

Figure 2.2 – Jurisdictional Growth in Transmission Circuit Length

Excluding QNI, Powerlink's increase in circuit length is commensurate with (but above) the increase in demand and customers. In the case of NSW and Tasmania, there is a reasonable correlation between the growth drivers and circuit length increases. South Australia has accommodated growth within existing transmission line assets.

Clearly, the facts indicate that the Victorian and South Australia systems had spare capacity in the right locations to cater for growth. Even moving to probabilistic planning approaches does not explain the ability to absorb 30 – 35% differentials between growth and capacity. Transmission lines come in very discrete and lumpy sizes. The question of whether they were "over built" or "gold plated" at the time they were constructed is a different question. This judgement can only be made in the context of the information that was available at the time the investment decision was made – it is not sufficient to simply apply a hindsight test. Whilst Evans & Peck is not in a position to make this judgement, we do conclude that spare capacity existed and it is difficult to support CME's conclusion that "*prima facie, it seems implausible"* that legacy assets have not had an impact on the comparative performance of TNSP's.

Evans & Peck has also examined the growth in transmission transformer capacity. This is shown in Figure 2.3. Victoria is the only jurisdiction where the increase in transmission transformer capacity (500, 330, 275 and 220kV primary voltages) has not outstripped demand. Capacity has grown 27% in order to cope with a 35% growth in peak demand. The ratios are significantly higher in the other states, particularly Queensland. In Queensland's case we have separately identified capacity associated with QNI and non-load driven SVC transformers. Even after this adjustment, the increase is substantial.

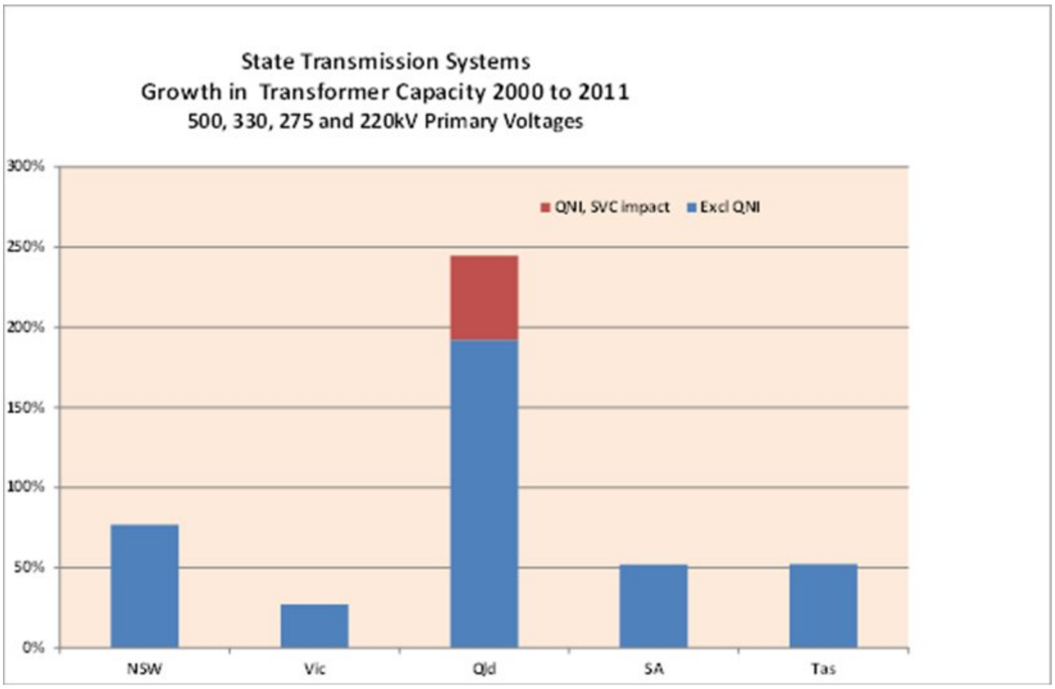

Figure 2.3 – Jurisdictional Growth in Transmission Transformers Capacity

Before drawing conclusions that Victorian investment has been prudent, and in other jurisdictions excessive, Evans & Peck has examined the starting and ending positions of each of the TNSP's in relation to installed capacity per unit of load served. This is demonstrated in Figure 2.4.

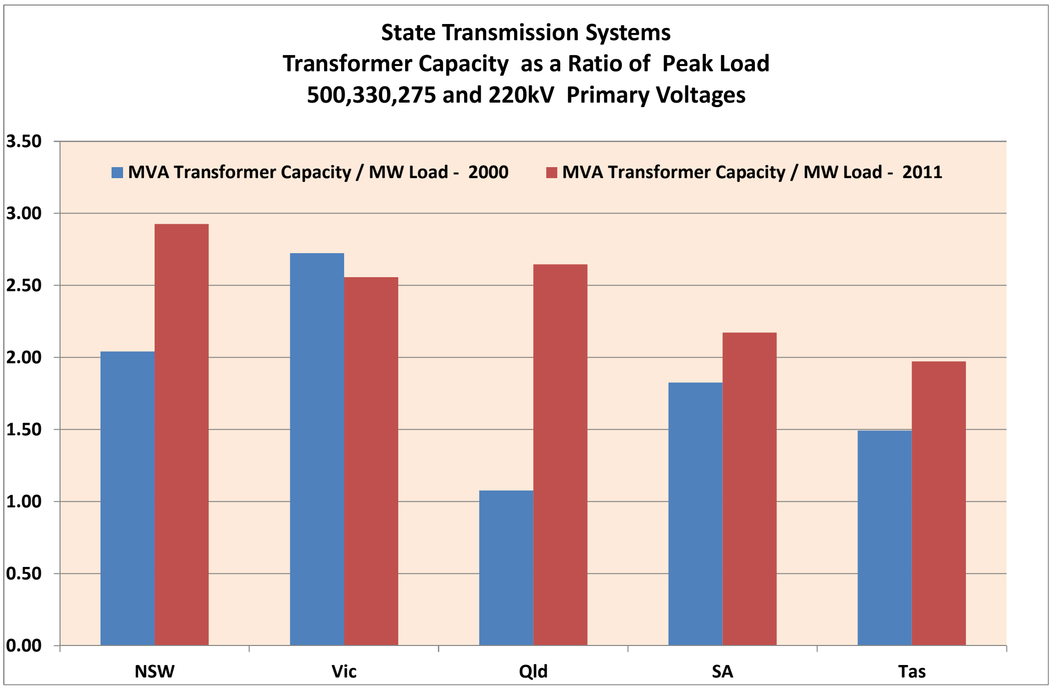

Figure 2.4 – Transmission Transformer Capacity to Load Ratio – 2000 and 2011

At the start of the period, Victoria had an installed transmission transformer capacity of 2.72 MVA / MW of load. This was 33% higher than NSW, the next highest in the NEM. Conversely, Qld was 1.18 MVA / MW, 43% of the Victorian value.

Over the 11 year the period, Victoria has essentially maintained the MVA / MW ratio by increasing capacity commensurate with load growth, whilst the other states have increased their ratios. Significantly, differences between the states have tightened up, with little material difference in the ratio at the end of the period, particularly in NSW, Victoria and Queensland.

One conclusion, albeit subject to the need for very rigorous analysis, is that at the start of the period, from a transmission transformer capacity position, Victoria was in "good shape", with Queensland significantly under built, with the other states in between. It is arguable that the last decade has seen the evolution of a robust transmission system in Queensland from a poor starting position, whilst Victoria has enjoyed the benefit of prudent and /or excess capacity in the transmission system at the beginning of the period. The other jurisdictions fall between these two extremes.

We have not explicitly considered the impact of new generation in this report, albeit noting the emergence of the wind industry in the southern states and generation in South West Queensland over the period. The partial replacement of the multiunit Swanbank A, Swanbank B, Swanbank C and Swanbank D power stations close to Brisbane with a single Swanbank E unit of half capacity would also be expected to be an "exogenous" factors impacting transmission.

3 The Impact of Asset Build Timing on Revenue

In Section 2 it was demonstrated that significant differences probably existed in the relative adequacy of the transmission infrastructure in each state 10 years ago. We believe it reasonable to conclude that Victoria had spare transmission capacity (that does not to automatically imply over building at the time of build) and that Queensland was "under built". Other jurisdictions were between these two extremes. It is of importance to understand the impact that the "carry forward" of legacy capacity (or indeed the "carry forward" of inadequate capacity) may have on annual revenue.

The capital component of each TNSP's annual revenue allowance is based on:

- A return of capital (depreciation)
- A return on capital (WACC based) based on depreciated value held in the Regulatory Asset Base

Newer assets generate higher revenue than older assets, simply because they are less depreciated. Further complicating this issue is the fact that "boom" construction periods, particularly characteristic of the period prior to the onset of the GFC, resulted in significant real price increased in the cost of infrastructure, including electrical infrastructure.

Figure 3.1 quantitatively demonstrates this impact. By way of an example, under the assumptions outlined, an asset built in 1991 would return only 50% of the regulated revenue (in 2012) that the same asset would if built in 2011.

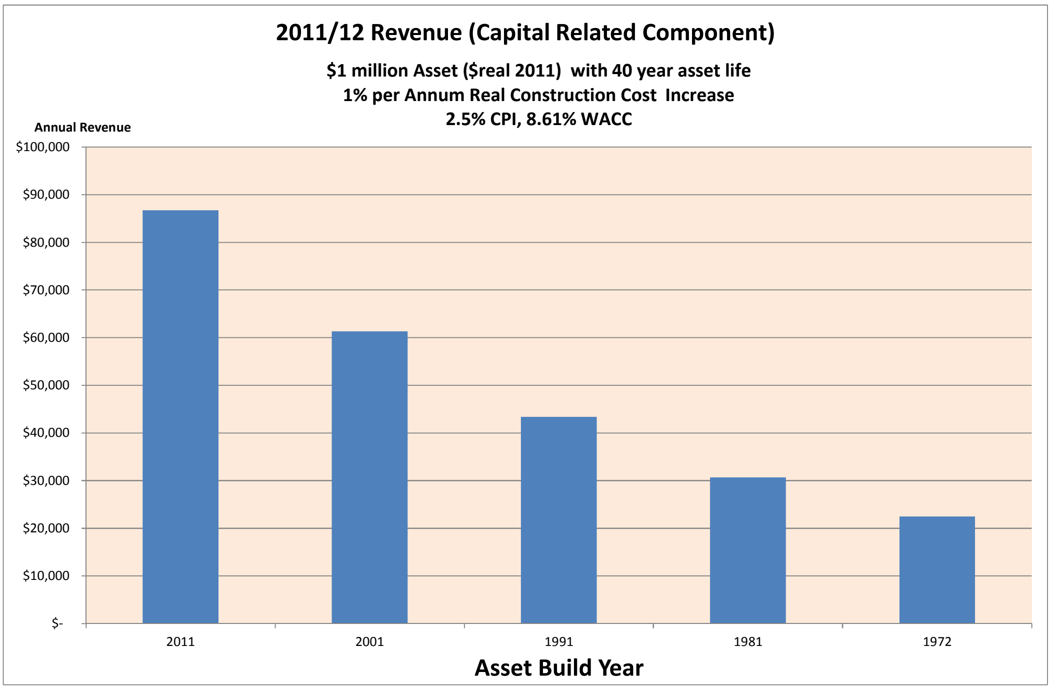

Figure 3.1 – Impact of Asset Build Year on Current Year Revenue Recovery

In order to provide an extremely broad indication of the relative age of the state transmission systems, Evans & Peck has calculated the proportion of transmission line circuit length and transmission transformer capacity that existed at 30 June 2000 as a proportion of that at 30 June 2011. We have simply averaged lines and transformers and acknowledge the crude nature of this calculation. The results are shown in Figure 3.2.

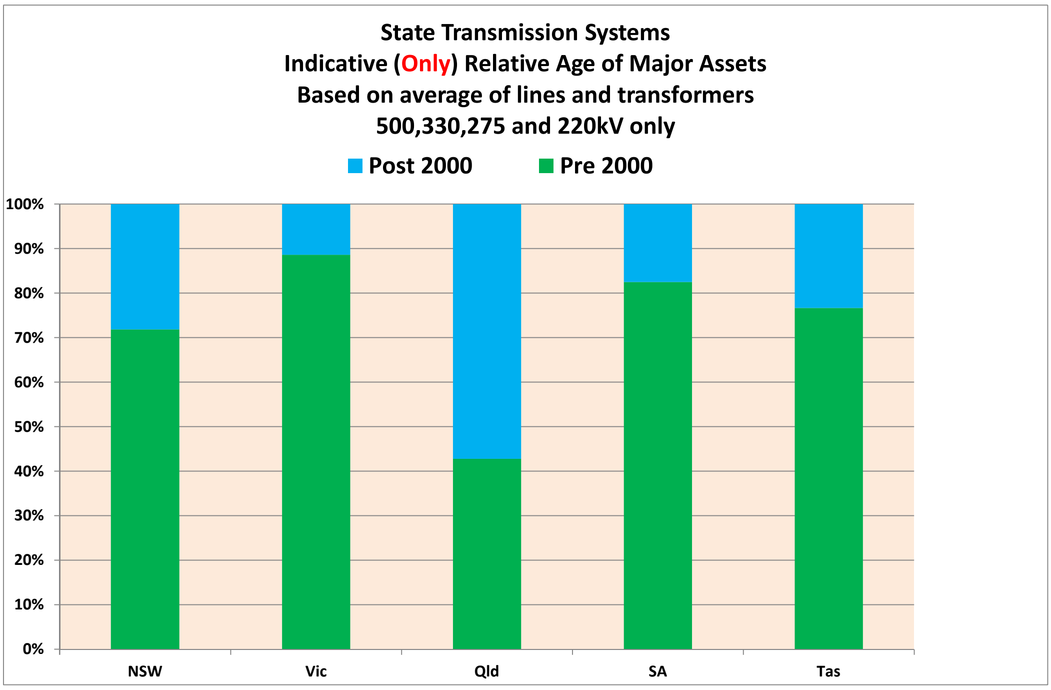

Figure 3.2 – Indicative (Only) Estimate of Relative Transmission System Age Profile

Notwithstanding the limitations of this analysis, it is evident that the Victorian transmission system is relatively "old" and the Queensland system relatively "young" with other systems between these extremes.

The implications of this analysis is that even if all other things such as planning prudency, utilisation of assets, ownership impacts, geographical factors, load density etc. were equal, the pricing outcomes for customers in Queensland would be higher simply based on when the assets were constructed. Conversely, those in Victoria would be lowest.

4 Conclusions

A key assumption underpinning CME's arguments attributing "planning" and "ownership" as major explanations of "superior outcomes" for transmission customers in Victoria, is the dismissal of the impact of "exogenous" factors such as excess capacity in legacy assets.

Evans & Peck believes that dismissal of such factors is inappropriate, and therefore undermines the validity of CME's analysis. In our previous report prepared for GridAustralia, Evans & Peck raised issues relating to the comparative benefit Victoria may have received due to the existence and location of the 500kV network.

In this report, we have shown that over the last 11 years, the Victorian transmission network has been able to absorb a 35% growth in demand and a 22% growth in customers without any material increase in line length. Evans & Peck is of the view that this demonstrates that the transmission lines at least had spare capacity. Whether they could be considered to have been "over built" or "gold plated" needs to be considered on the basis of the information available at the time of investment, not in hindsight, but the fact remains they had spare capacity. On the other hand TNSP's in Qld, NSW and Tasmania have found it necessary to added transmission lines to cope with growth in demand and customers.

Victoria has added transformer capacity at a rate slightly below load growth. However, at the start of the 11 year period under consideration, they had the highest ratio of installed capacity to load. This ratio has basically been maintained. Conversely, at the commencement of the 11 year period, Queensland had a transformer ratio less than half that of Victoria. At the end of the period, this ratio is reasonably consistent across the jurisdictions. In Evans & Peck's view, this probably indicates a "catch-up" program was in place in Queensland, which necessitated both substation and transmission line construction. Other jurisdictions fall between these outcomes.

The net result of Victoria carrying excess capacity forward, and Queensland carrying deficiencies in capacity forward is that Victoria now has a relatively old asset base, and Queensland a younger asset base (with other jurisdictions in between).

The result of this age difference, irrespective of factors such as planning policy, ownership, geography, customer density etc., is that Queensland will have higher pricing outcomes than Victoria (with other jurisdictions in between).

In summary, our conclusion is that Victoria entered the 21st century with a highly interconnected mature transmission system with spare capacity in the "right" locations. At the other end of the spectrum, Queensland entered the 21st century with an under built non interconnected system and needed to add capacity over a wide geographical area. Other jurisdictions fall between these extremes. The resultant difference in age profile of investment streams results in significantly different pricing outcomes between the states.

These would appear to be the material factors explaining differences in pricing outcomes between the States rather than differences in planning arrangements.

In this report, we have sought to test the reasonableness of CME's decision to exclude so called "exogenous" factors from their analysis concluding that "ownership" and "planning" were the primary variables explaining differences in outcomes between the states. In our view, such exclusion is unreasonable and is likely to lead to "conclusions of convenience", rather than conclusions based on fact.

NERA
ECONOMIC CONSULTING

US Transmission Planning Arrangements – Competitive Procurement and Independent Planner Model

A Report for Grid Australia

21 November 2012

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1. Overview

This report has been prepared by NERA Economic Consulting (NERA) at the request of Grid Australia.

Grid Australia has sought advice on transmission planning arrangements as they apply in North America. In particular Grid Australia is interested in understanding the extent to which competitive procurement has been used to date in the US for new transmission investment, and the anticipated expansion in the use of competitive procurement as a result of the Federal Energy Regulatory Commission's (FERC) Order 1000 (FERC Order 1000). In addition, Grid Australia has asked us to outline the history behind the introduction of not-for-profit Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs) in North America.[1]

Competitive procurement arrangements can be characterised as where an independent planning body identifies an investment solution to meet an identified need, and then calls for tenders from transmission owners to build and own this solution.

The adoption of competitive procurement arrangements for transmission continues to largely be in the formative stages in North America, either having only recently been introduced and as yet untested (in the case of California) or still in the process of being introduced (in Alberta and as part of some ISO/RTO filings in response to FERC Order 1000). The exception is Texas, where competitive procurement was adopted by the Public Utilities Commission in 2008 for transmission extensions to designated Competitive Renewable Energy Zones (CREZ)[2]. As a consequence, there is currently little available outturn evidence on the effectiveness of competitive procurement arrangements for transmission in North America.

Prior to the recent FERC Order 1000 filings, the proposed competitive procurement arrangements were also limited to particular subsets of transmission extensions: in California arrangements introduced in 2010 applied to economic transmission investments only (distinct from investments to meet reliability standards); in Alberta the proposed arrangements will only apply to transmission investments designated as critical transmission infrastructure; in Texas competitive solicitation has been limited to extensions of the network to CREZ areas.

FERC Order 1000 has resulted in an increase in the number of ISO/RTOs proposing to introduce competitive procurement arrangements, which in some cases will be applied to a broader range of transmission investments. This includes Midwest ISO (MISO), ISO-New England (ISO-NE, for public policy investments only) and Southwest Power Pool (SPP). These revised provisions are not yet in place, and will first require FERC approval.

However not all of the ISO/RTO filings in response to FERC Order 1000 have proposed competitive procurement for transmission investments, with some ISO/RTOs instead proposing a 'revised sponsorship' model, under which parties can submit alternative projects (network and non-network) to address a need identified by the ISO/RTO. Under this approach, the ISO/RTO has less of a 'central planner' type role, and more of a coordination

[1] The terms RTO and ISO are FERC-defined terms, and in practice there is very little difference between the legal definition of each.

[2] Geographic areas with optimal conditions for wind power development

role between potentially competing solutions planned by others. Although there is competition between parties to propose solutions (and therefore no ‘right of first refusal’ for the incumbent transmission owner), the party that proposes the solution selected by the ISO/RTO is then the party called on to build and own that solution. This approach has been proposed by PJM, NY-ISO, ISO-NE (for reliability and market efficiency projects) and California (for reliability projects) in their FERC Order 1000 filings.

Several ISO/RTOs (including MISO, ISO-New England and SPP) and the Transmission Owners in PJM have also specified in their FERC Order 1000 compliance filings that the revisions proposed to their transmission processes should only be considered if FERC first finds that the current right of first refusal clauses seriously harm the public interest, and provides evidence that a modification is of public necessity.

In the US there continues to be a high degree of common ownership between transmission and other electricity sector activities, including generation and electricity retailing, albeit that in some regions they are unbundled into affiliate corporations. This is in contrast to the industry structure in Australia, where transmission has been unbundled into separate, for-profit entities. The continued vertical ownership between transmission and generation interests was a key factor leading to the introduction of the ISO/RTO model in the US. The introduction of an independent party to operate and plan the network enabled the restructuring of the sector (and in particular open-access to the transmission networks) to be achieved without the requirement for divestment of transmission ownership from other utility activities.

The governance arrangements adopted for ISO/RTOs in the US is also different from those applying to the Australian Energy Market Operator (AEMO) in its current independent planner role in Victoria. In particular there is often a formal role for all stakeholders in both the governance and planning processes of the ISO/RTOs. In addition, there is oversight and approval by FERC in relation to both the planning approach adopted by the ISO/RTOs and the specific transmission investments which are identified as a result of those planning processes. FERC’s role in approving specific investments is a feature of its role as economic regulator, and the cost-of-service approach taken to regulating transmission assets in the US.

Finally we note that the transmission planning arrangements in North America continue to draw a distinction between ‘reliability’ and ‘economic’ investments, and that reliability standards are primarily determined by a body outside of the ISO/RTOs (specifically the North American Electric Reliability Corporation (NERC)).

1.1. Structure of this report

The remainder of this report is structured as follows:

- Section 2 summarises the requirements of FERC Order 1000, focusing on the requirement for ISO/RTOs to remove any Right of First Refusal (ROFR) provisions under their current planning arrangements;
- Section 3 reviews the details of the FERC Order 1000 compliance filings of key RTO/ISOs in the US, as well as the developments in Alberta, in relation to competitive procurement;

- Section 4 provides a background to the establishment of ISO/RTOs in the US, as well as their governance and oversight arrangements; and
- Section 5 summarises the arrangements in the US for determining reliability standards.

2. FERC Order 1000 and the Right of First Refusal

FERC Order 1000, issued on July 21, 2011, became effective on October 10, 2011.[3] The Order addressed reforms on planning and cost allocation principles as they apply to new transmission facilities. It requires each public utility transmission provider to consider transmission needs driven by public policy, increase coordination in planning of interregional projects (which are crucial to meet the Renewable Portfolio Standards in some regions), and ensure non-discrimination for non-incumbent transmission owners (TO) or developers.

One of the main elements of FERC Order 1000 is the removal of provisions that grant ROFR to incumbent TOs. Currently, incumbent TOs in some US regions have exclusive right to build and own high voltage transmission projects that are required for reliability reasons, as well as any upgrades of their existing facilities. FERC Order 1000 requires ISO/RTOs to revise their transmission planning processes so that they remove the ROFR, except for local transmission facilities.[4]

To comply with FERC Order 1000, the ISO/RTO will need to:

- demonstrate that the regional planning process has appropriate, non-discriminatory qualification criteria;
- identify the information that must be submitted by prospective transmission developers, and the date by which such information must be submitted; and
- include a description of a transparent and non-discriminatory evaluation process for the selection of proposed transmission facilities.

The requirement to remove ROFR provisions from ISO/RTO tariffs has revived earlier debates about the need to introduce a competitive procurement framework with clear and objective criterion to evaluate and choose transmission projects from competing providers. Many RTO/ISOs in their recent FERC Order 1000 compliance filings are considering a competitive solicitation process where independent developers and existing TOs have an equal opportunity to propose to construct transmission facilities included in the RTO/ISO's plan.

Below we discuss the two major models that ISOs and RTOs are proposing in order to remove the ROFR.

We also note that several ISO/RTOs including MISO, ISO-NE and SPP, as well as TOs in PJM have specified in their FERC Order 1000 compliance filings that the revisions proposed to their transmission processes should be considered only if FERC first finds that their current contracts with transmission owners are not protected by the Mobile-Sierra doctrine.[5] These ISOs/RTOs claim that the Mobile-Sierra doctrine protects these contracts and the current ROFR clauses, unless the FERC can conclude that the contracts seriously harm the public

[3] Docket No. RM10-23-000

[4] Local transmission facilities are those located entirely within the TO's retail service territory or footprint and for which the TO has not been granted regional cost allocation treatment.

[5] Line Co. v. Mobile Gas Service Corp., 350 U.S. 332 (1956); FPC v. Sierra Pacific Power Co., 350 U.S. 348 (1956). Under the Mobile-Sierra doctrine, FERC is required to demonstrate serious harm to the public interest as a prerequisite to mandating modifications to operating agreements between transmission owners and the ISOs.

interest and provides evidence that a modification is of public necessity. PJM TOs are arguing that they willingly signed contracts with PJM with the understanding that their ROFR would be preserved. These ISO/RTOs as well as the TOs at PJM insist their current transmission plans have been beneficial to the public by providing robust transmission expansion and in some cases provided proof of increased participation by non-incumbent developers.

In relation to the process for FERC 1000, filings in response to the Order were due by November 12, 2012. FERC will review those filings and invite comments from interested parties. It is likely that hearings will be held, prior to FERC making a final decision in relation to the filings.

2.1. Alternative models for increasing competition in transmission investment

Transmission planning by RTOs/ISOs in the US to date has largely followed a ‘project-sponsored’ approach. Under this approach, incumbent transmission owners or other developers took a proactive role in presenting the ISO/RTO with a potential project. The ISO/RTO was mostly reactive to the projects presented, and evaluated them (including the extent they would actually solve a reliability or congestion concern) on an ad-hoc basis. The ISO/RTO might then decide to open a process to solicit non-transmission alternatives, such as generation proposals or demand response programs, to compare them with the project proposed by the developer(s). If the alternatives were considered less efficient, the proposed transmission project would be accepted, and the party that proposed the initial investment (generally the incumbent TO) was given the right to own and develop the project, and to recover the costs of those projects under a regulated transmission access charge.

The project sponsored approach has been used mostly in the context of reliability projects, but also for transmission projects justified on economic grounds. Under this framework, an ISO/RTO may engage in lengthy evaluation processes when receiving multiple projects, including for projects that ultimately may not be needed, since they could be submitted even before the ISO/RTO had identified a need. This approach also generally limited participation to ISO/RTO stakeholders and other interested parties in the initial evaluation of transmission needs.

Following FERC Order 1000, US ISOs/RTOs are currently considering variants of competitive approaches to address the requirement to remove any ROFR in the regional transmission planning process. The approaches that have been filed vary from ‘pure’ competitive solicitations or tenders, to hybrid/stepped processes, as described below.

a) **Pure competitive solicitation (‘the competitive model’)**, where a central, not-for-profit planner (ISO/RTO) identifies both the need for transmission investment as part of a formal process, and the most prudent and cost-effective transmission (or non-transmission) solution that should be built to meet the ISO/RTO identified need. That solution may be a solution recommended by a participating transmission owner, some other stakeholder, or a wholly separate ISO/RTO solution. Then the ISO puts out to tender the ownership and construction of the specific investment solutions identified (all potential bidders have the same window to submit their proposals, including incumbent TOs).

b) **A hybrid process ('revised project sponsored model')** in which the not-for-profit regional planner (ISO/RTO) determines, as part of a comprehensive planning process and often with the input from incumbent TOs and reliability organizations, a range of transmission issues or needs. Once the needs are identified, the ISO/RTO allows interested parties a window to propose specific transmission projects that could solve the problem.[6] After the ISO/RTO evaluates the projects proposed, an initial solution is identified and a further window opened where alternative projects (including non-transmission solutions, but also transmission projects from other parties) are solicited and evaluated against the costs and benefits of the project initially proposed. If a proposal gets approved, the developer who proposed that project has the obligation to build the project.

The first approach is the one currently adopted by AEMO in Victoria, Australia and also by CAISO in California (for economic and policy-driven transmission projects) and earlier in Texas (for investments to CREZs). It is also the approach proposed by Alberta (for investments designated as 'critical infrastructure') and MISO and SPP (in their FERC Order 1000 filings). The second approach is being proposed by PJM, NYISO and California (for reliability projects), in their FERC Order 1000 filings. ISO-NE has proposed to use a competitive solicitation process (ie, the first approach) for public policy projects and a revised project-sponsored approach (ie, the second approach) for reliability and market efficiency projects in response to FERC Order 1000. It has also provided arguments as to why its current planning process is more cost-effective, and therefore should be preferred over the alternative in its filing.

The two models both generally meet the requirements of being non-discriminatory against non-incumbent transmission developers. However the revised project-sponsored model may differ and not be entirely comparable with a pure competitive solicitation model, depending on the details of implementation.

In particular, the revised project-sponsored approach may include more discretion on the part of the ISO/RTO relating to the timing for presenting proposals – the sponsor approach allows more flexibility to ISOs in deciding whether they will first solicit a proposal (both a project and the cost of the project) from the incumbent TO and subsequently invite other potential developers to present their proposals.[7] The rationale of the two step process is that it may work better for reliability projects, since the incumbent TOs may have lower costs in analysing and recommending a solution than an independent provider, so the delayed timing may avoid the latter incurring unnecessary proposal preparation costs. In the end the ISO will assign the project (including right of developing and owning the facilities) to the party that proposes the best solution, regardless of the timing of the proposal.

A further key difference is that in the pure competitive model a solicitation window is not open until the projects have been determined following all the necessary technical studies and ISO consultation process. At that point, a window to present transmission proposals to fulfil a specific identified project is open to all potential competitors at the same time.

[6] This initial response window may be open to all potential developers, or only to the incumbent TO, depending on the ISO/RTO.

[7] For example, in California, independent transmission developers will have a different time window to present their proposals to CAISO in relation to reliability projects (they are allowed to submit proposals only after the incumbent TO has proposed a project).

3. North American experience with competitive procurement

3.1. California ISO (CAISO)

On June 4, 2010, the California ISO (CAISO) proposed a new transmission planning process to facilitate long-term planning for transmission additions and upgrades. This planning process was designed to comply with FERC Order 890,[8] in the light of increasing pressure to build transmission to meet renewable standards.

Under CAISO's 2010 Revised Transmission Planning Process (RTPP), CAISO will determine the appropriate transmission projects needed to meet reliability, economic and other needs and to address public policy requirements as part of a comprehensive, inclusive planning process, which would provide opportunities for stakeholders' participation as well as input from interested project sponsors during the earlier stages of the planning process.

The RTPP also introduced a competitive procurement process for economic and policy-driven investments, and also reliability projects where market benefits are above 10 per cent of costs. It also provided that in the case that an economically driven or public-policy driven project is abandoned by the competitively-selected project sponsor, CAISO will conduct a further competitive solicitation. This measure was included to ensure all projects are built and to mitigate concerns of load-serving transmission owners that they would be obligated to build any abandoned projects.

There has only been one planning cycle since the inception of the 2010 planning process, and CAISO did not identify any eligible projects for competitive solicitation. As a consequence, there is no experience to date of how these provisions have operated.

In October 2012, CAISO's FERC Order 1000 compliance filing[9] introduced some changes to the 2010 RTPP process, to more clearly conform to the stated competition goals of FERC Order 1000. In particular:

a) CAISO proposes to add to the RTPP and transmission tariff language a clarification that it will select from competing transmission or non-transmission solutions to meet reliability needs and enhance the simultaneous feasibility of long-term congestion revenue rights that are the most prudent and cost-effective. Under the earlier RTPP version, the incumbent TO had the responsibility to build and own any reliability-related project.

b) CAISO's filing proposes to set forth ex ante which transmission facilities are eligible for regional cost allocation and which are not, eliminating the existing discretion on the part of the individual TOs to seek regional cost treatment for a given facility.[10] Under

[8] Order 890 was issued in February 2007 and was designed to strengthen the pro forma open-access transmission tariff by reducing opportunities for undue discrimination, facilitating FERC's enforcement of measures to avoid discrimination and increasing transparency in the rules regarding planning and use of the transmission system. Order 890 required that transmission providers implement a coordinated, open, and transparent transmission planning process that satisfies nine planning principles: (1) coordination; (2) openness; (3) transparency; (4) information exchange; (5) comparability; (6) dispute resolution; (7) regional participation; (congestion studies; and (9) cost allocation for new projects.

[9] California ISO, Order No. 1000 Compliance Filing, Docket Number ER13-103, October 11, 2012.

[10] FERC Order 1000 does not require that local transmission facilities be subject to approval at the regional level unless the incumbent transmission provider seeks regional cost allocation for them.

CAISO's filing, a TO's ROFR will be limited to facilities under 200kV which are located within the existing utility's retail service territory or footprint of the transmission owner. CAISO is therefore expanding opportunities for independent transmission providers beyond those implied by FERC Order 1000 requirements, which allows ROFR as long as the project is not part of a regional plan (and therefore not subject to regional cost allocation), but does not impose a voltage limit.

c) For economic and policy-driven projects CAISO retains the RTPP language which contemplates a competitive solicitation for project sponsors to seek to finance, own, and construct the transmission elements identified during the planning process.

The following sections describe the proposed approach for economic and reliability investments in more detail.

3.1.1. Economic and policy-driven projects

The process applying to economic and policy-driven investments[11] can be summarised as follows:

- Economically driven or policy driven projects can be proposed by a TO, a market participant, the California Public Utilities Commission,[12] or the California Energy Commission.[13] They cannot be proposed by CAISO itself. These projects are approved if they are found to be beneficial according to CAISO's evaluation methodology.
- In relation to specific approved projects, CAISO will then conduct a competitive process to select a party to build and own that specific project.
- The RTPP establishes a transparent set of criteria to solicit and evaluate competing proposals. One of the ten factors used to evaluate competing proposals is a voluntary demonstration of cost containment measures, or willingness to enter into a binding cost cap that would preclude the project sponsor from recovering costs above the cap from the CAISO's tariff based cost recovery mechanism.[14] Other factors include quality of materials or dependability of technologies to be used for a particular transmission facility. CAISO will also consider possession of rights-of-way when evaluating competing project sponsors as this could reduce the cost and regulatory hurdles during the siting and permitting process.
- Where there is only one qualified project developer, that sponsor may then proceed to the appropriate siting authority (such as the California Public Utilities Commission) to obtain the approval for siting.

[11] Economically-driven network transmission projects include those projects where the economic benefits of the upgrade or addition (primarily lower energy production costs. including generation cost dispatch and losses, in the region, reduced congestion, or lower generation capacity needs) are expected to exceed the project costs. Policy driven projects are those intended to meet renewable targets.

[12] The California Public Utilities Commission regulates California's privately owned electric, natural gas, water, railroad, telecommunications, rail transit and passenger transportation companies.

[13] The California Energy Commission is an institution which is unique to California, and has a number of responsibilities including supporting renewable energy and promoting energy efficiency.

[14] California ISO, Order Conditionally Accepting Tariff Revisions and Addressing petition for Declaratory Order, Docket No ER10-1401, December 16, 2010, p. 65.

- If two or more project developers qualify to build the same project and propose to seek siting approval from the same authority, CAISO will first encourage the sponsors to collaborate to submit a single joint proposal to construct and own project. If the project developers do not want to collaborate, CAISO will defer the choice of project sponsor to the state siting authority such as the California Public Utilities Commission.[15] The state regulatory commission ultimately decides who builds and own the projects in this case, and takes into account the ultimate impact on ratepayers.

- In the case that project developers technically qualify to construct the same project, but apply for siting approval from different siting authorities, CAISO will determine which project sponsor should construct and own the project. The selection criteria include, among other things:

    - the demonstrated cost containment capabilities of the project sponsor, including any binding agreement by the project sponsor to a cost cap;
    - specific advantages or strengths that a project sponsor has to build and own the project;
    - a comparative assessment of the initial qualification criteria;
    - a project sponsor's financial resources and capabilities;
    - the project sponsor's technical and engineering qualifications;
    - the project sponsor's current and expected capabilities to finance;
    - license and construct the facility and then to own and maintain it; and
    - the project sponsor's prior record regarding the construction and maintenance of any transmission facilities.

- If the selected project involves an upgrade or improvement to, addition on, or a replacement of a part of an existing incumbent TO facility, the TO will construct and own such upgrade, improvement, addition or replacement facilities unless the selected project developer and the TO agree to a different arrangement. Where there is no approved project developer, CAISO shall direct the Participating TO in whose PTO Service Territory or footprint either terminus of the facility being upgraded or added is located, to build the element or elements. The previous Approved Project Sponsor shall be obligated to work cooperatively and in good faith with CAISO, the new Approved Project Sponsor (if any) and the affected incumbent TO, to implement the transition.

3.1.2. Reliability projects

The process applying to reliability investments (where CAISO determines that they will be open to a competitive process) can be summarised as follows:

- CAISO identifies the reliability needs that need to be resolved by either a transmission solution or a non-transmission solution.

[15] The CPUC is responsible for approving siting of transmission and granting a "Certification of Public Necessity and Convenience" (CPCN), for transmission projects at 200 kV and above and a "Permit to Construct" (PTC), for projects between 50kV and 200kV

- After CAISO posts the results of the reliability studies and identifies the reliability needs that need to be resolved, it opens a “request window” under which incumbent transmission owners are required submit suggested reliability solutions.

- The incumbent transmission owners must submit a proposal to address each of CAISO’s identified reliability needs on their respective systems within 30 days of CAISO’s posting of its reliability assessment. All other interested parties are permitted to submit their suggested reliability solutions up to one month after the deadline for the participating transmission owner solutions.

- As per FERC Order 1000 compliance filing, CAISO will identify the transmission solution (or a non-transmission alternative) that meets the identified reliability need in the most prudent and cost effective manner. The selected project sponsors will be given the right to build and own the proposed projects. These solutions will then be included in the development of the comprehensive Transmission Plan.

- Where a competing process is opened for reliability projects, CAISO will review the proposals and will provide a report detailing the results of its comparative analysis and the reasons for its selection decision.

- When reliability projects cannot be completed by an approved project sponsor, CAISO may *at its discretion*, either (a) assign the project to the incumbent TO in whose service territory or footprint of the facility being upgraded or added is located, to build the element or elements of the solution or (b) open a competitive solicitation to seek an alternative project sponsor to build and own the project.

- In the new RTPP, incumbent TOs retain the right to build upgrades to their existing transmission facilities (which is allowed under FERC Order 1000).

3.2. Midwest ISO (MISO)

MISO has proposed to use a competitive model for new transmission investment, integrated within its planning process.

MISO will first perform an open transmission planning process including stakeholders (called an ‘inclusive evaluation process’) for a 19-month planning cycle. MISO receives projects from any interested parties that represent regional solutions to regional needs identified by MISO. Once these projects are reviewed, MISO will include the approved projects in their regional plan.

The projects included in the regional plan that are eligible for recovery in regional open access tariffs are identified as Open Transmission Projects (OTP).[16] These projects are eligible for construction by non-incumbent transmission developers. Only ‘Multi-Value’ Projects, related to reliability and public policy goals, and projects involving regional economic benefits, will be identified as OTPs and eligible for a competitive solicitation. Under MISO’s FERC Order 1000 compliance filing, MISO has proposed to put out these projects for tender at the end of the 19 month cycle, so that interested developers present their proposals and MISO will select the proposal that seems most cost effective. The developers

[16] These are the only types of projects selected in the regional plan for purposes of cost allocation per FERC Order 1000.

that are selected from the competitive process will have the obligation to own, operate, maintain, repair, and restore facilities associated with the OPT.[17]

MISO proposes to allow the state regulatory commissions to have the first opportunity to select the developer for OPT projects, acknowledging that some states within its territory have ROFR laws and holding two separate processes would be inefficient. In the case that the applicable state commission declines to make the selection or is unable to choose during the specified time period, MISO would select the developer based on criteria including: the full life cycle cost of the project and the potential developer's abilities to efficiently operate, maintain, repair, and restore the transmission facilities associated with the transmission project.

The MISO evaluation process allows for re-evaluation on an as-needed basis during the early stages of the project implementation. MISO can cancel or reassign the transmission facility if a reevaluation determines the project is no longer beneficial due to delays or increased costs.

The incumbent utilities will maintain their ROFR for local transmission facilities, upgrades to existing facilities, facilities associated with use of an existing right of way, and facilities whose costs are otherwise allocated only to a single pricing zone.

3.3. PJM

In its FERC Order 1000 compliance filing, filed on October 25, 2012, PJM has proposed a revised sponsorship approach for new transmission projects. The proposal revisions clarify non-incumbent developer's rights to propose transmission and non-transmission alternative projects through PJM's sponsorship model. PJM's process will require PJM to first assess transmission needs and undertake a solicitation process where all developers can propose projects to be included in the Regional Transmission Expansion Plan (RTEP). Developers will have the opportunity to propose projects limited only if the need is a reliability need and the time needed to complete the project is too short to hold a competitive solicitation. PJM believes that a revised sponsorship approach is the more efficient approach because it puts the needs out to the market and the market will determine the solution.

Transmission projects have been separated into three needs categories as shown in

[17] Recognizing that some projects are a mix of upgrades to existing facilities and new construction, MISO has proposed to label a project as new, and eligible for a competitive solicitation, if the new line totals more than 20 contiguous miles.

Table 3.1. Each category has a different project proposal process.

Regarding Long-Lead Projects, if PJM does not receive proposals in the first 120 day window to address all violations, economic constraints or public policy requirements, PJM will have a second proposal window. If proposals are still not received PJM will identify the solution and designate the project to the incumbent transmission owner.

Table 3.1
Project Categories and Time-Differentiation Rules

Project Category	Project Type	In Service Date	Length of Planning Cycle	Proposal Window Length (days)	Number of Projects Since 1999
Long-Lead Projects	Reliability, Economic, or Public Policy related enhancement or expansion	Greater than 5 years from date PJM posts the need	24-months	120	40
Short-Term Projects	Reliability, Economic, or Public Policy related enhancement or expansion	Greater than 3 years but less than 5 years from date PJM posts the need	12-months	30	10
Immediate-need Reliability Projects[18]	Reliability-based enhancement or expansion	Less than 3 years from date PJM posts the need	Left to PJM's discretion	Left to PJM's discretion	0

For Short-Term Projects, PJM will identify the solution and designate the project to the incumbent transmission owner if no proposals are received during the first 30 day proposal window. For Immediate Need Reliability Projects, PJM will hold a shortened solicitation if there is sufficient time. Otherwise it will identify the solution and designate the project to the incumbent transmission developer.

Transmission developers will apply annually for pre-qualification status during a specified pre-qualification window. Developers will be asked to respond with evidence that they maintain the necessary financial resources and technical expertise to construct, own and operate transmission facilities.

PJM has proposed to allow the incumbent transmission owner to meet its reliability needs or service obligations under the following circumstances:

- an upgrade to an incumbent transmission owner's own transmission facilities;
- new facilities located solely within incumbent transmission owner's Zone and the costs are allocated solely to the incumbent;

[18] PJM can also determine that a project falls under the Immediate-need Reliability Project if the projected time to complete the enhancement or expansion requires immediacy based on factors such as longer than normal time necessary to obtain regulatory approvals or acquire equipment.

- new transmission facilities located solely in the incumbent's Zone and not included in the RTEP for cost allocation purposes;
- facilities located on the incumbent transmission owner's right of way and the project would alter the incumbent's use and control of its existing right of way under state law.

In each of these cases PJM will designate projects to the incumbent transmission owner in the Zone in which the facilities are located. PJM will also designate a project to the incumbent transmission owner when required to under state law, regulation or administrative agency order.[19]

3.4. NY – ISO

The New York Independent System Operator (NYISO) uses a Comprehensive System Planning Process (CSPP) which is conducted over a two-year period and currently consists of a Local Transmission Planning Process, a Reliability Planning Process and an Economic Planning Process. NYISO evaluates and monitors the reliability of the system and any prospective changes to it. In most cases NYISO does not expressly direct or determine upgrades, but it will determine the need if identified. The current CSPP does not include a right of first refusal for incumbent transmission owners for transmission projects to address regional needs therefore NYISO does not need to make changes to comply with FERC Order 1000 in this regard.

In its FERC Order 1000 compliance filing, NYISO proposed few changes to its CSPP and did not propose to use a competitive solicitation process to select transmission developers. NYISO did propose the addition of a Public Policy Requirements process that complements the processes for reliability and economic projects.

The CSPP begins with the Local Transmission Planning Process where each transmission owner develops a transmission upgrade plan based on needs of the service territory. This is an open process when all stakeholders can review and comment on needs addressed by the transmission owners. Afterwards, NYISO will request solutions (including project and cost of the project) from incumbent and non-incumbent transmission developers to identified needs and analyse them to determine whether they are sufficient in addressing the need. Concurrently, NYISO will evaluate backstop solutions in case none of the proposed solutions are adequate.

If more than one solution proposed by transmission developers will meet the identified need, the selection of developer is made by the appropriate governmental agency, not by the NYISO. Additionally, the New York State Public Service Commission reviews any regulated backstop projects proposed by transmission developers.

[19] PJM Interconnection, Inc, Transmission Planning and Cost Allocation By Transmission Owning and Operating Public Utilities, Docket No. RM10-23-000, October 25, 2012.

3.5. ISO – New England

ISO-NE is the RTO for the New England area, covering Maine, Vermont, Massachusetts and New Hampshire.[20] ISO-NE's compliance filing differentiates between public policy transmission projects and reliability and economic projects.

3.5.1. Public policy transmission planning

The New England State Committee on Electricity (NESCOE), a not-for-profit organization managed by appointees by the six New England Governors, will be the primary body responsible for identifying state and federal public policies that will create a need for transmission investment.[21]

ISO-NE will undertake scenario studies to provide a cost/benefit analysis of alternate solutions for the NESCOE to review. At that point, if the NESCOE (with input from the Public Advisory Committee (PAC), made up of interested stakeholders), determines that a transmission investment is necessary, it will provide a list of one or more options that the states are interesting in pursuing and ISO-NE will initiate a competitive solicitation. If the NESCOE does not want to proceed, the public policy transmission planning process will be terminated until the next planning cycle.

In Stage One of the solicitation process, ISO-NE will solicit projects in response to needs from both incumbent and non-incumbent transmission developers and will review the proposals for completeness, performance and other requirements.

ISO-NE will establish a deadline for Stage One proposals depending on the complexity of the project. Under the proposal, incumbent transmission developers in areas with transmission investment needs will still be subject to a contractual obligation to build transmission projects and will be required to submit proposals during Stage One. Due to this obligation, the development costs of Stage One will be recoverable only by an incumbent transmission developer or by a nonincumbent utility if the project was initiated by a written request by the NESCOE or a regulatory authority.

After Stage One the NESCOE must provide a written request for more detail from a subset of proposals in order for the process to move to Stage Two. At Stage Two developers will submit engineering designs to be reviewed for adverse system impacts and other system integration issues. NE-ISO will perform the analysis of Stage Two proposals. Stage Two costs are recoverable for all entities whose projects were selected. If the expected cost of a project increases by more than 25 per cent from the Stage One cost estimate to the Stage Two estimate, the developer must have this cost increase approved by the NESCOE.

ISO-NE will report to the NESCOE and PAC on a preferred list of public policy solutions and whether these solutions will also address any reliability needs from the Regional System Plan. The NESCOE or other public utility regulators can then approve a project to be included in the Regional System Plan.

[20] ISO-NE became an RTO, but did not change its name.
[21] ISO-NE may also identify public policies which may drive transmission needs.

3.5.2. Reliability and market efficiency transmission planning

The process for reliability and market efficiency transmission planning will also follow a two-phase process, except in the case of a reliability project that is needed within five years of a completed needs assessment. For these more immediate reliability projects, ISO-NE will use its current sponsored project model, where ISO-NE undertakes an on-going needs assessment and evaluates the adequacy of concepts for projects offered by the transmission owners and other stakeholders in collaborative solutions studies. The exception to using the RTO-led development process for reliability projects needed in five years or less was proposed by NE-ISO to mitigate negative impacts to near-term reliability needs due to delays under the proposed two-stage selection process.

The two phase selection process for all other reliability and market efficiency projects will start with the NE-ISO issuing a public notice inviting all qualified transmission developers to submit Phase One proposals to address identified needs. Incumbent transmission owners will be required to individually or jointly propose a Phase One proposal and will continue to have an obligation to build.

NE-ISO will review the Phase One proposals for feasibility and to make sure the solution does satisfy the transmission need. NE-ISO will also review whether the need is eligible to be constructed by a non-incumbent transmission developer.[22]

ISO-NE will provide the PAC with a list of compliant Phase One proposals. The PAC will solicit stakeholder input to select a subset of the most competitive projects in terms of cost, electrical performance, future system expandability, or feasibility. Once the projects have been selected for Phase Two, NE-ISO will work with the transmission developers to develop the proposed solutions. These solutions will be submitted to PAC for its input and ultimately ISO-NE will select the final project for development.

3.5.3. NE-ISO's arguments against the proposed two-stage process

NE-ISO foresees delays associated with the two-stage process due to insufficient resources to review, study, and develop follow-up requests for needed data for multiple projects simultaneously. Additionally, NE-ISO believes this approach could lead to litigation-related delays from disputes from competing developers due to proposed costs and performance claims. NE-ISO estimates that the new process will add an additional year or more for project development. Additionally, if this process leads to increased risk of litigation NE-ISO believes developers will be less willing to propose projects.

Under the current process, NE-ISO leads a collaborative stakeholder process to identify needs and oversee the development of transmission solutions. NE-ISO has concerns that under the new process they will be forced to analyse and select from projects that may not be the best alternative or may not be cost effective due to lack of collaboration. NE-ISO believes that processing and evaluating multiple projects rather than collaborating to produce one realistic

[22] Projects that involve upgrades to existing incumbent transmission owner facilities, and projects where the costs are not eligible for regional cost allocation under the RTO tariff will be allocated only to the incumbent TO and recovered from the local customers of the incumbent TO.

project will essentially multiply the costs to consumers by the number of realistic projects proposed.

A further potential inefficiency highlighted by NE-ISO is the inability to modify the needs and proposed solutions midstream. Currently, if there are changes to the load forecast, or resource additions or retirements, the investment need could be postponed or certain portions of projects can be removed from a project list, leading to significant cost savings. NE-ISO believes under the proposed model if a need changes materially or a project requires a significant adjustment the process would have to be restarted.

3.6. ERCOT

In 2005, Senate Bill 20 established Texas's Renewable Energy Program and directed the Texas Public Utilities Commission (PUC) to identify CREZs. In 2008, the PUC selected the CREZ transmission plan (CTP) from four proposed scenarios provided by ERCOT in the CREZ Transmission Optimization Study. The CTP designated five CREZs and also designated the transmission projects to be constructed to deliver the wind energy to Texas consumers. The PUC undertook a transmission service provider (TSP) selection process in 2008 and 21 entities submitted initial expressions of interest and 14 entities were assigned responsibility for specific projects identified in the CTP. The PUC noted the importance of selecting the right number of TSPs in order to spread financial risk, introduce innovative technologies, diversify skills and materials, and avoid unnecessary coordination difficulties.

The three categories of transmission projects that were subject to a competitive selection process are described in Table 3.2.

Table 3.2
Transmission Project Categories

Category	Purpose	Eligibility	Award
Default Projects	Refit, rebuilt, or enhance existing transmission infrastructure	Only TSPs that own the existing infrastructure	8 incumbent TSPs
Priority Projects	Alleviate current or projected transmission congestion issues	Incumbent TSPs that own and operate existing facilities geographically proximate to the priority projects to avoid delays	2 incumbent TSPs
Subsequent Projects	All other identified projects	All TSPs	8 TSPs including 2 non-incumbents and 2 joint ventures

The application process required a TSP to submit a proposal for a transmission project to the PUC who issued a certificate of convenience and necessity (CCN) if the application is approved. The PUC selected entities based on several factors including the expected capabilities to finance, licence, construct, operate, and maintain the facilities in the most beneficial and cost-effective manner; the expertise of the staff; and the projected capital costs and operating and maintenance costs for each CTP facility.

Open stakeholder proceedings are usually used to determine the final route for a transmission project. Once approved, the TSP could acquire the necessary right of way, begin construction and exercise the power of eminent domain where necessary.

ERCOT proposed a procedure to allow assigned TSPs to recommend improvements to projects identified in the CTP, if they reduced the cost of transmission or increased the amount of generating capacity that the transmission facility can accommodate. This process allowed ERCOT to review modifications proposed by TSPs, with input from stakeholders if time allowed, and provided ERCOT the flexibility to approve minor modifications. If the proposed changes required the project acquiring a CNN, the PUC reserved the right to decide if the modification would be adopted.

As of October 2012, the estimated cost of transmission projects under the CTP has increased from an estimated $4.9 billion dollars at the start of the process in 2008 to $6.9 billion dollars.

ERCOT is not subject to FERC jurisdiction, as the scope of the market falls within a single state and there are limited interconnections to other markets. ERCOT has therefore not needed to file compliance with FERC Order 1000.

3.7. Southwest Power Pool (SPP)

SPP has proposed to use a competitive solicitation process that involves minimal revisions to its current regional transmission planning process. SPP will still continue to use its existing Integrated Transmission Plan to determine which transmission projects are needed to meet system needs. SPP has proposed to solicit proposals from qualified entities, including incumbent and non-incumbent developers, for certain transmission facilities classified as Competitive Upgrades. Competitive Upgrades must be approved by the SPP Board of Directors like other transmission projects and also meet all the following criteria:

- Integrated Transmission Plan upgrades or high priority upgrades[23],
- Operate at or above 300 kV,
- Not a rebuild of an existing facility and do not use rights-of-way where facilities currently exist, and
- Are located where selection of a transmission owner through the selection process does not violate applicable law in a jurisdiction in which the Competitive Upgrade is to be built.[24]

Proposals for Competitive Upgrades will be evaluated by an independent panel of industry experts who will recommend entities to construct each project to the SPP Board of Directors. In turn, the Board of Directors will approve the entity that will be designated to construct

[23] ITP Upgrades include approved upgrades that address reliability, economic, and public policy needs that were addressed during the ITP process. High Priority Upgrades tend to be economic upgrades.
[24] Southwest Power Pool. Exhibit No. SPP-1, Direct Testimony of Carl A. Monroe. November 12, 2012, Page 9.

each Competitive Upgrade. The panel will make recommendations based on a scoring system consisting of base points and incentive points. Base points will be awarded based on necessary elements to construct and maintain a facility, such as design, management, operations, cost, and financial viability. Incentive points will be awarded to a respondent who also submitted the Detailed Project Proposal during the ITP for the approved Competitive Upgrade.

SPP has proposed that, in limited circumstances when a facility is needed in a short time-frame to address system reliability concerns, it will use a streamlined process to designate a transmission owner for the project. This process will only be used for projects classified as Competitive Upgrades, if the reliability need must be resolved in less time than it takes to complete the competitive solicitation process and develop the project, and if SPP could not identify another reasonable mitigation measure to relieve the issue for long enough to conduct the competitive solicitation process. This exception process was proposed by SPP in the light of possible litigation delays.

Under SPP's Highway/Byway and Balanced Portfolio cost allocation methodology, 'Highway' projects (projects with a nominal operating voltage of 300 kV and above) qualify for region-wide funding and therefore will be classified as Competitive Upgrades. 'Byway' projects (projects with nominal voltage of less than 300 kV), provide only local benefits and address local needs and therefore will not qualify as Competitive Upgrades. Upon reviewing past data, SPP has determined that nearly 80 per cent of the total investment dollars approved under its cost methodology has been for facilities that are 345kV and above and therefore they expect the vast majority of projects to be eligible to be Competitive Upgrades.

3.8. Alberta

In 2010, the Alberta Electric System Operator (AESO) filed an application with the Alberta Utilities Commission (AUC) for approval of a competitive solicitation process to determine eligibility to apply to the AUC for construction, operation or both, for critical transmission infrastructure (CTI). The application was required under the Electric Statutes Amendment Act in 2009 and has not yet been approved. The AESO is not subject to FERC Order 1000 requirements. The first projects proposed to be assigned in a competitive manner will be two single-circuit 500kV transmission lines in 2017.

CTI is defined in the Electric Statutes Amendment Act as a transmission facilities project that is:

- an intertie;[25]
- to serve areas of renewable energy;
- a double circuit transmission facility that is designed to be energized at a nominal voltage of 240 kV,
- designed to be energized at a voltage in excess of 240 kV, or
- in the opinion of the Lieutenant Governor in Council, critical to ensure the safe, reliable and economic operation of the interconnected electric system.

[25] An intertie is a transmission facility that links one or more electric systems from outside Alberta to one or more points on the Alberta Interconnected Electric System.

The need for a CTI project is determined by the lieutenant-governor in council and is approved by the Minister of Energy. A CTI project can be assigned to a developer by the Minister of Energy or determined through a competitive process. All other transmission infrastructure projects are approved by the AUC.[26]

- Under the AESO proposed single owner competitive process model, the successful proponent would own the facilities and would be responsible for all project activities including the upfront development work, engineering, procurement, construction management, financing, as well as operation and maintenance of the facilities.

- The process will consist of three stages: the Request for Expressions of Interest stage, the Request for Qualifications stage, and the Request for Proposals stage. Any developer can participate in the first two stages; however, the third stage will be for a subset of developers selected by AESO based on their qualification submission.

- The Request for Proposals submissions will be evaluated on a pass/fail basis based on technical and financial requirements and the final decision will be based on criteria including the project costs and any other factors determined by AESO. In order to cover costs during the final stage, the process allows for compensation for a portion of costs.

There is currently a debate regarding project final approval once a project has been assigned to a developer. The AUC has interpreted the legislation to require the AESO to direct the transmission developer to submit an application for construction to the AUC. However, AESO has proposed for the outcome of the competitive process to be approved based solely on whether the selection process was fair and allowed for all qualified parties to submit proposals.

[26] AUC, Part A: Statutory Interpretation”, February 2012.

4. Not-for-profit ISO/RTO model

Many of the electricity markets in North America are characterised by the presence of a not-for-profit, market-wide Independent System Operators (ISOs) or Regional Transmission Organisations (RTOs). Currently there are ten ISO/RTOs, operating in the following markets:

- California Independent System Operator (CAISO)
- PJM Interconnection - RTO
- New York Independent System Operator – ISO
- Midwest Independent System Operator ISO (MISO) - RTO
- Southwest Power Pool (SPP) - RTO
- ISO – New England - RTO
- Electric Reliability Council of Texas (ERCOT) - ISO
- New Brunswick System Operator (NBSO)
- Alberta Electric System Operator (AESO)
- Ontario Independent Electricity System Operator (IESO).

Much of the restructuring in the US electricity sector occurred in the late 1990s. The first ISO was created in 1996 (ERCOT). PJM, CAISO, NYISO and ISO-NE were approved as ISOs between 1997 and 1998. MISO was approved in 2001.[27] SPP RTO did not develop until 2004.

FERC Orders 888 and 889 in 1996 established the basis to open the nation's wholesale bulk electricity system[28] to competition by requiring vertically integrated electric utilities to provide open access to independent producers or other third parties to their transmission system, on the same terms and rates as available to the utility's native load. These Orders also required utilities to functionally unbundle their charges for wholesale generation and transmission services, and outlined the principles that would govern the formation of ISOs.[29]

[27] MISO was officially approved as the nation's first RTO in December 2001, although its competitive energy bid-based markets did not start operation until April 2005.

[28] The bulk power system or Bulk Electricity System (BES), includes all transmission facilities operated at 100 kV and above, as defined by NERC.

[29] These FERC Orders also required the establishment of an electronic bulletin board called Open Access Same-time Information System (OASIS), which allows users to receive data on current operating status and transmission capacity of any transmission provider.

After several years of experience under Order 888, FERC expressed concern about possible inefficiencies in transmission open access rules given the multiple transmission operators that continued to exist in most regions, outside of an ISO. As a result, in 1999 FERC issued Order 2000, to advance the formation of Regional Transmission Organizations (RTOs). FERC encouraged all FERC-regulated entities that owned, operated or controlled transmission to participate in an RTO. The Order laid out the general principles around which RTOs should be developed.

According to FERC, ISOs and RTOs are designed to "promote efficiency in wholesale electricity markets and to ensure that electricity consumers pay the lowest price possible for reliable service".[30]

FERC has four required characteristics and eight required functions for an entity to be an RTO.

The four required characteristics are:

1. *Independence*: the RTO must be independent of any market participant.
2. *Scope and regional configuration*: the RTO must serve an appropriate region.
3. *Operational authority*: the RTO must have operational authority for all transmission under its control.
4. *Short-term reliability*: the RTO must have exclusive authority for maintaining the short-term reliability of the grid it operates.

Of particular relevance to this report, the eight functions of an RTO include:

1. *Planning and expansion*: the RTO must be responsible for planning and directing needed transmission expansions, additions and upgrades that enable it to provide efficient, reliable and non-discriminatory transmission service, coordinating its planning with appropriate state agencies.
2. *Interregional coordination*: the RTO must ensure the integration of reliability practices within an interconnection and market interface practices among regions.

4.1. Rationale for adoption of the ISO/RTO model in the US

In the US, a large portion of the transmission grid in those states which have restructured their electricity sector is still owned by the incumbent investor-owned utilities, which continue to also own generation and retailing functions, albeit that in some regions they are unbundled in affiliate companies.

At the time of restructuring in the US, there was severe reluctance on the part of the investor-owned utilities to divest their transmission assets. As a consequence, in Order 888, the FERC took a non-intrusive alternative to requiring the divestiture of generation or transmission assets, by requiring only functional unbundling. Likewise, FERC Order 2000 did not explicitly require ISOs or RTOs to have a non-profit structure.

[30] FERC Order No. 2000, Docket No. RM99-2-00, p. 1.

The approach to restructuring in the US is in contrast to that adopted in Australia, and in other countries such as England and Wales, New Zealand, and Spain, where all public or private entities were required to undertake legal unbundling of generation and transmission activities, and where for-profit independent transmission companies have been established.

The main barrier to adopting unbundled, for-profit regional transmission companies in the US was most and foremost political. Any requirement on vertically integrated electricity utilities to divest assets would need be imposed by the relevant State regulator (Public Utility Commission, or PUC). However, not all States that restructured their electricity industry required the electric utilities to divest their generation assets, let alone their transmission assets. Some States passed laws explicitly requiring utilities to sell all or a share of their power plants (California,[31] Connecticut, Maine, New Hampshire, and Rhode Island, for example), since they considered that the separation of power generation ownership from power transmission and distribution was a prerequisite for retail competition. Yet no PUC imposed a requirement on utilities to divest their transmission assets. Many times the PUCs were not explicit in their unbundling requirements, leaving it to the utility to propose a method that satisfied the PUC's unbundling objectives and the strategic and economic objectives of the utility. The utility prepared a company restructuring plan which could include selling its assets or, alternatively, transferring its assets to an unregulated subsidiary company. Negotiation and compromise between the PUC and the utility were part of the process of finalizing the restructuring plan.

At the time of restructuring, there were several options available to ensure independence of transmission operation:

1. The first was for vertically integrated utilities that owned and operated both generation and transmission to transfer the operational control of transmission to an independent agency.

2. The second was to allow the utility to maintain both ownership and control over transmission, but to ensure that the utility would offer open access transmission rates, subject to the FERC requirements.

3. The third option was to request divesture of transmission assets to an independent agency.

All of the US states that restructured their electricity sector adopted the first approach, with the exception of the Southwest, Southeast, and Northwest regions. None of the US regions adopted the third approach.

As a consequence, independent, non-profit ISOs or RTOs were developed to operate, plan and control the transmission assets on a regional basis in most regions. They were also tasked with management of congestion on real time basis, and dispatch of energy resources following a security-constrained, bid-based economic procedure. The formation of ISOs enabled restructuring to proceed and ensured a coordinated regional transmission planning process, without requiring that utilities divest their transmission assets.[32]

[31] In California, the three major investor-owned utilities sold most of their generation assets but it was politically infeasible to require divesture of their transmission assets.

[32] We note that the formation of ISOs/RTOs occurred prior to the 2003 black-outs on the East Coast of the US, and was not a response to concerns about system failure. The 2003 black-outs led to a change in the status of the NERC reliability

The Southwest, Southeast and Northwest opted for the second approach. A considerable fraction of the transmission assets in the northwest and the southeast at the time of restructuring are owned and controlled by public entities like the Bonneville Power Administration, Western Area Power Administration, and the Tennessee Valley Authority.

While there were several proposals to create for-profit RTOs that would combine ownership and operation of transmission (third approach), these proposals met strong resistance from stakeholders. The most promising proposal for a regional for-profit Transco was "Alliance RTO" in the Midwest ISO, filed before FERC in June 1999. Although FERC initially approved the Alliance companies' development plan, it eventually rejected the plan, finding that the Alliance RTO lacked sufficient geographic scope to exist as a stand-alone entity.[33]

In 2005, FERC issued a Notice of Proposed Rulemaking (2005) that included, among other measures, incentives for utilities to divest their transmission assets to an independent Transco. Incentives included: allowing recovery of accumulated deferred income taxes[34] and allowing utilities to adjust the book value of transmission assets to remove the disincentive associated with federal capital gains tax liabilities. However to date, there have not been any further Transco proposals.

As an alternative, Independent Transmission Companies (ITCs) emerged as entities that consolidate transmission asset ownership but turn over operational control to an RTO to address any independence concerns. On January 1, 2001, shortly after most of the energy sector restructuring took place in the US, and after the development of ISOs, legislation enacted by the state of Wisconsin led to the formation of a for-profit transmission company, American Transmission Company (ATC).[35] ATC was required to become a member of the Midwest ISO (MISO), the not-for-profit RTO in the region where ATC operates. Currently there are three ITCs operating within MISO.

FERC stated that independent transmission entities, such as RTOs or ITCs must be operationally independent from market participants and has established standards to assure that independence is maintained. For example, FERC established narrow limits on the "active ownership" or voting interests any market participant could have in an RTO or ITC governance structure.[36]

4.2. Continuing vertical integration

Common ownership between transmission and generation entities continues to be a feature of the US electricity sector, in those markets where there are ISOs/RTOs.

standards (as discussed in section 5.1) and the introduction of penalties for non-compliance, rather than changes to the planning arrangements.

[33] See FERC 62,529-30 (2001). FERC found that the public interest would be better served if the Alliance companies placed their transmission facilities under the control of the Midwest Independent System Operator (MISO), which was approved that same year.

[34] There are tax provisions that allowed companies that sell transmission assets to defer the gain on the sale of those assets.

[35] ATC was formed through the transfer of assets primarily from investor-owned utilities and capital contributions by public-power entities in Wisconsin, Michigan, and Illinois. The latter have fractional ownership of the company. As electric transmission is ATC's only business, its only profits are through its earnings on transmission assets.

[36] FERC Order No. 2000 at 31,068-73.

For example, of the eight transmission owners in the NY-ISO area, the majority continue to also own generation assets. Similarly, in PJM although some transmission owners are now independent shareholder-owned companies, others remain part of a larger shareholder-owned utility that may also own generation, distribution, retail and other businesses. Although in all cases non-transmission affiliates are functionally-separated from transmission activities, it remains true that there remains a continuation of the common-ownership between transmission and generation activities which initially led to the introduction of the ISO/RTO model. This is a key difference between the US context and Australia, where transmission businesses have been separated from competitive generation and retailing activities.

4.3. Governance and oversight of ISO/RTOs[37]

The Productivity Commission comments in its Draft Report that the effectiveness of its preferred model for transmission network planner (which has an expanded role for AEMO as a national, not-for-profit network planner) depends upon adequate resourcing and effective governance.[38] It also suggests that the planner should be subject to greater scrutiny, through a combination of AER oversight of the transparency and regular reporting of modeling parameters, assumptions and results, and data inputs, as well as periodic reporting to ensure that the planning framework was delivering optimal outcomes in line with the National Electricity Objective.[39]

The governance arrangements currently applying to AEMO differ materially from the arrangements applying to the ISO/RTOs in the US. In particular, the ISO/RTO governance and planning arrangements typically involve an increased, formal role for stakeholders/members (particularly in the case of PJM).

There is also a higher level of oversight of the ISO/RTO in the US. FERC has an approval role both in relation to the planning processes adopted by the ISO/RTO and also, as part of its role as economic regulator, in approving the individual investments resulting from the planning process.

The remainder of this section briefly summarises the governance arrangements applying to PJM, NY-ISO and CAISO, as well as FERC's oversight role.

4.3.1. PJM

PJM is an independent, not-for-profit organisation, incorporated as a limited liability company. PJM has a two-tier governance structure with an independent board and a members committee:

1. The Board is responsible for maintaining PJM's independence and, by exercising their prudent business judgment, ensuring that PJM fulfils its business obligations and legal and regulatory requirements, as well as preventing any market participants from having

[37] The material in this section, and in the following section 5.1, has been largely summarised from NERA's earlier report for the Australian Energy Market Commission, *Planning Arrangements for Electricity Transmission Networks: An International Review*, 12, April 2012, available at http://www.aemc.gov.au/Market-Reviews/Open/transmission-frameworks-review.html. Further detail in relation to the network planning arrangements in PJM, California and New York can be found in that report.

[38] Productivity Commission, Electricity Network Regulatort Frameworks, Draft Report, Volume 2, October 2012, p. 527.

[39] Op cit, p. 525.

undue influence over the operation of PJM or exerting market power in PJM markets. The members of the PJM Board must have no personal affiliation or ongoing professional relationship with, or any financial stake in, any PJM market participant.

2. The members committee provides advice to the Board by proposing and voting on changes and new programmes, with the Board having the final say. The committee is composed of five voting sectors representing the five PJM membership categories (transmission owners, generation owners, distribution businesses, end-use customers[40] and retailers[41]). Every member of PJM has a representative on the committee. Only one affiliate of a member corporate entity may vote in the committee. Other committees and groups meet on specific issues and report to the members committee.[42]

In addition, the Regional Transmission Expansion Planning (RTEP) process undertaken by PJM provides for input and review of the assumptions incorporated in the planning process by a number of PJM committees and working groups. The Transmission Expansion Advisory Committee (TEAC)[43] provides the primary stakeholder forum for the on-going exchange of ideas, discussion of issues and presentation of RTEP upgrades. The responsibilities of the TEAC include the provision of:

- Comments and recommendations on the scope and assumptions for RTEP studies, including economic/market efficiency analysis;
- Comments on the RTEP analysis at defined points throughout the RTEP process cycle;
- Comments and recommendations on the RTEP that will be proposed to the PJM Board for consideration and approval, as necessary; and
- Comments and recommendations on RTEP matters as requested by the PJM Board.

4.3.2. NY-ISO

NYISO is the ISO for the state of New York. NYISO is both system operator and market operator. It is an independent, not-for-profit corporation.

NYISO is governed by a 10-member Board of Directors, which includes the NYISO President & CEO. The Board is comprised of members with backgrounds in the electric power industry, finance, academics, technology, communications, and the law. The Board is required to be independent. Its members have no business, financial, operating or other direct relationship to any Market Participant or stakeholder.

NYISO staff report to the CEO, who in turn reports to the Board.

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[40] Normally large customers who wish to participate directly in the wholesale markets.

[41] This category is formally known as "other suppliers" and consists of other entities engaged in buying, selling or transmitting electric energy, capacity, ancillary services, financial transmission rights or other services.

[42] Ex officio regulatory members, emergency customer load reduction program special members and associate members do not have voting rights in the members committee. Associate members do not have voting rights in any stakeholder activities, working groups or committees.

[43] TEAC membership and participation are open to parties as described in the PJM OA Schedule 6, Section 1.3(b): "…(i) all Transmission Customers, as that term is defined in the PJM Tariff, and applicants for transmission service; (ii) any other entity proposing to provide Transmission Facilities to be integrated into the PJM Region; (iii) all Members; (iv) the agencies and offices of consumer advocates of the States in the PJM Region exercising regulatory authority over the rates, terms or conditions of electric service or the planning, siting, construction or operation of electric facilities and (v) any other interested entities or persons."

In parallel there are two stakeholder committees – the Operating Committee[44] and the Business Issues Committee[45] – which contain representation from: transmission owners; generation owners; other suppliers; end-use consumers; and public power and environmental parties. These committees report to a Management Committee, which in turn reports to the Board.

4.3.3. CAISO

The CAISO is a non-profit "public benefit corporation" whose mission is to operate electric grid facilities in California for the purpose of ensuring efficient use and reliable operation of the transmission grid. The CAISO is in charge of developing state-wide transmission planning and assessing transmission proposals from transmission owners and other parties.

The CAISO is governed by a Board of Directors. The CAISO Board consists of five Governors nominated by the governor of California and confirmed by the Senate, that serve staggered three-year terms.

The Board selection process involving stakeholders is outlined in a FERC order issued July 1, 2005. The Board Nominee Review Committee is comprised of six stakeholders from each of the following member-class sectors: transmission owners, transmission-dependent utilities, public interest groups, end-users and retail energy providers, alternative energy providers, and generators and marketers. Each sector is responsible for selecting its own six members to serve on the committee. Typically, the Committee becomes active beginning late summer each year.

4.4. Oversight of ISO/RTO planning decisions

Under the North American arrangements, there is oversight of both the planning process conducted by the ISO/RTO, as well as the individual planning decisions which result from the process.

FERC approves the planning processes adopted by the ISO/RTO, and any subsequent amendments to those processes, with the exception of ERCOT which is not subject to FERC jurisidiction.

Of the three ISO/RTO arrangements reviewed in NERA’s earlier report, the FERC has an explicit approval role in relation to the transmission planning processes adopted in each of these arrangements, specifically:

- The RTEP process adopted by PJM
- The Comprehensive System Planning Process adopted by NY-ISO
- The Transmission Plan adopted by CAISO.

[44] The Operating Committee coordinates operations, develops procedures, evaluates proposed system expansions and acts as a liaison to the New York State Reliability Council (which is a third-level reliability organisation (NERA anc NPCC being the other two) whise scope is limited specifically to New York State.

[45] The Business Issues Committee establishes rules related to business issues and provides a forum for discussion of those rules and issues.

In the US, there is also explicit approval by FERC of the specific investment decisions made by the independent ISO/RTO. This oversight and approval function arises through FERC's specific role as economic regulator in relation to the transmission tariffs charged by the ISO/RTO, which in turn cover the cost of the specific transmission investments included in the transmission plan. The costs of local transmission facilities below 200 kV are generally recovered from PUC-approved tariffs that are charged to those customers connected to the transmission system in the TO's service territory. The investment-specific approval reflects the rate-of return regulatory approach adopted to determine transmission charges in the US.

5. Relationship between planning arrangements and reliability standards

5.1. Reliability standards

The reliability-standards applied in each of the ISO/RTO areas are in the main determined outside of the ISO/RTOs themselves. Specifically, the NERC develops and enforces reliability standards for the North American bulk power system. As a consequence, in the US there is a separation between the body that develops the reliability standard and the body which plans to meet that standard. Supplementary regional reliability standards may be developed by the ISO/RTO (for example PJM has developed regional standards).

FERC certified NERC as the national Electric Reliability Organization for the United States in 2006.[46] Prior to this, NERC's guidelines for power system operation and accreditation were referred to as *Policies*, for which compliance was strongly encouraged yet ultimately voluntary. Since 2006 (and as a direct result of the 2003 system blackouts in the North East),[47] NERC Policies have been revised into *Standards*, and now NERC has authority to enforce those standards on power system entities operating in the United States, as well as several provinces in Canada, by way of significant financial penalties for noncompliance (of up to $1 million per day per violation).

NERC's role is to oversee the reliability and security of the bulk power system in North America. To achieve that, NERC develops and enforces mandatory minimum transmission reliability standards, monitors and enforces compliance with those standards, assesses resource adequacy (done annually via a 10-year forecast) and provides educational and training resources as part of an accreditation program to ensure power system operators remain qualified and proficient.[48] NERC also investigates and analyses the causes of significant power system disturbances in order to help prevent future events.

NERC is governed by a twelve-member independent Board of Trustees.

5.2. Distinction between reliability and market-benefit investments

The ISO/RTO planning process in PJM, New York and California all continue to include a distinction between reliability and market-benefit investments. Reliability investments are those needed in order to ensure that the network meets required reliability standards, which are predominantly those determined by NERC (as discussed above).

The RTEP process adopted by PJM involves the identification of reliability upgrades, based on PJM's baseline reliability analysis. In addition to these upgrades, PJM also consider

[46] FERC was given the authority to do this under powers obtained in the Energy Policy Act of 2005, following the 2003 Northeast blackout.

[47] Making the NERC standard mandatory was a recommendation set out in the U.S.-Canada Power System Outage Task Force, *Final Report on the August 14th Blackout in the United States and Canada*, April 2004, available at https://reports.energy.gov/.

[48] Included in NERC's certification was a provision to delegate authority for the purpose of proposing and enforcing reliability standards by entering into delegation agreements with regional entities. These regional entities are distinct from the ISO/RTOs, and there is not a one-to-one correspondence with the geography of RTOs/ISOs.

whether there may be transmission investments which could be justified on the basis of the reduction they would achieve in losses and transmission congestion, even if they do not contribute materially to reliability improvements. The optimal mix of upgrades is found which addresses the reliability violations and, as a secondary priority, improves market efficiency.

Under the Comprehensive System Planning Process adopted by the NY-ISO, it first undertakes a comprehensive reliability planning process (CRPP) to identify whether there is a need to undertake 'backstop' investments to address reliability needs. It also adopts a separate economic analysis (the Congestion Analysis and Resource Integration Study (CARIS)), which identifies the three congestion elements or paths of the grid which would have the highest production cost savings if the congestion were mitigated. NY-ISO then calls for proposals to address this congestion, and evaluates alternative proposals put forward by the market.

Finally, CAISO also draws a distinction in its Transmission Planning Process between reliability-driven transmission projects, economic transmission projects (ie, those driven by market benefits) and policy-driven projects (including those relating to renewable energy).[49]

[49] CAISO also considers some additional categories of investment: Locational Constrained Resource Interconnection Facilities (LCRI) Long-term congestion revenue rights (CRR) feasibility projects and merchant transmission projects.

Appendix A. Glossary

AESO	Alberta Electric System Operator
ATC	American Transmission Company
AUC	Alberta Utilities Commission
CAISO	California ISO
CARIS	California Analysis and Resource Integration Study
CCN	Certificate of Convenience and Necessity
CREZ	Competitive Renewable Energy Zones
CRPP	Comprehensive Reliability Planning Process
CSPP	Comprehensive System Planning Process
CTI	Critical Transmission Infrastructure
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
ISO	Independent System Operator
ISO-NE	Independent System Operator New England
ITC	Independent Transmission Company
MISO	Midwest ISO
NERC	North American Electricity Reliability Corporation
NESCO	New England State Committee on Electricity
NYISO	New York ISO
OTP	Open Transmission Project
PAC	Public Advisory Committee
PJM	Pennsylvania, Jersey, Maryland RTO
PUC	Public Utilities Commission - Texas

ROFR	Right of First Refusal
RTEP	Regional Transmission Expansion Planning process (PJM)
RTO	Regional Transmission Organisation
RTPP	Revised Transmission Planning Process (California)
SPP	Southwest Power Pool
TEAC	Transmission Expansion Advisory Committee
TO	Transmission Owner
TSP	Transmission Services Provider

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