# 16 Transmission reliability and planning

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| Key points |
| * Reliability settings for transmission networks in the National Electricity Market (NEM) are a key determinant of network design, performance and cost. * Setting reliability in transmission is complicated by inherent problems not present in distribution networks, such as network inter-linkages between regional service providers, difficulties observing latent levels of reliability and a high cost of failures. * The special features of transmission networks require that incentive regulation used in the NEM be complemented by reliability standards (instead of reliability targets as recommended for distribution networks) to achieve efficient outcomes. * There are three quite different reliability standards currently used in the NEM: deterministic standards, probabilistic planning and hybrids of the two. All involve inefficiencies. * Moving to a NEM-wide transmission reliability framework, underpinned by probabilistic cost–benefit informed standards is conservatively estimated by the Commission to generate large efficiency gains of $2.2 billion to $3.8 billion over 30 years. * The Commission’s proposed framework (the PC model), to be implemented NEM-wide, comprises: * A new NEM-wide reliability framework in which the Australian Energy Market Operator (AEMO), uses enhanced probabilistic planning methods and values of customer reliability to set cost–benefit based standards at the connection point level, and develops its National Transmission Network Development Plan. * Transmission service providers undertaking a robust cost–benefit analysis of large proposed augmentation and replacement investments (over a threshold value). * These would be pursued through an enhanced Regulatory Investment Test–Transmission process where revenue determinations are made by the Australian Energy Regulator (AER), with input from AEMO, prior to investments taking place. * Projects under the threshold would be funded through the general AER revenue allowance and be subject to the workings of incentive regulation. * AEMO acting as the planner of last resort where it considers underinvestment could put at risk efficient levels of reliability. * The benefits of the PC model would be severely undermined if standards were set at a jurisdictional level. If this were to occur, the AEMO planner model would yield greater gains than the proposed approach. |
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## 16.1 Introduction

The transmission network represents the ‘backbone’ of the NEM, and is the conduit through which most electricity is transferred from generators to distribution networks, and ultimately, to the consumer. It is therefore important that it is reliable.

There are two main concerns about transmission reliability.

First, there is a contemporary concern that, outside Victoria, reliability standards, combined with state-ownership of transmission network service providers (TNSPs), has led to excessive investment. Reliability settings are a major driver of the costs of investment in transmission networks (AEMC 2008a).[[1]](#footnote-1) The AER has been critical of reliability settings and, in particular, the:

... ambiguity inherent with deterministic reliability criteria, and the wide degree of scope this allows [transmission network service providers] to interpret and apply such standards ... [S]ignificant linkages exist between the standards and the regulatory processes used to set regulated revenues and to assess network performance. Poorly defined reliability requirements make it difficult for the AER to assess whether the capital expenditure proposals of [transmission network service providers] are genuinely required to meet reliability requirements. (AER in AEMC 2008a, pp. 14, 16)

Some have even called the capacity to use reliability standards as a basis for inefficient investment the ‘Trojan Horse’ strategy. Others, using less colourful analogies, have argued that:

… divergent transmission standards across the NEM result in … potential for undue influence and discretion for [transmission network service providers]. (The Group,[[2]](#footnote-2) cited in AEMC 2008a, p. 14)

Second, there is a concern to ensure that future arrangements result in adequately reliable transmission networks. There are three main risk factors that, unless tempered by an appropriate reliability framework, could potentially lead to underinvestment. These include the:

* desirable shift away from prescriptive deterministic reliability standards
* presence of more commercially TNSPs (whether achieved through privatisation or better governance of state-owned network businesses)
* ongoing application of incentive regulation.

There is already broad agreement among most stakeholders, including all governments, that the current reliability framework has provided scope for some TNSPs to make inefficient investments, with a shift away from prescriptive standards seen as desirable. Given this, the emphasis of this chapter is on the second concern focusing on reliability settings within future transmission planning frameworks.

Any assessment of reliability settings within future transmission planning frameworks must consider the:

* special features of transmission networks (section 16.2)
* broader planning context and economic regulation (section 16.3)
* appropriate criteria for making judgments about the most efficient framework (section 16.4).

The chapter then draws conclusions about the desirable characteristics of a new framework for transmission reliability in the NEM (section 16.5). Operational and performance standards are addressed briefly towards the end of this chapter (section 16.6). A summary of the proposed transmission planning reforms is then outlined in section 16.7. A proposed new approach for new connections and other separable investments is also put forward (section 16.8). The approach is underpinned by findings from detailed analysis of current and proposed (albeit fluid) models for transmission reliability and planning, which are presented in appendix F. Appendix F also contains a full description and analysis of existing systems, along with recent models proposed by the Australian Energy Market Commission (AEMC) and Grid Australia, the latter in response to the draft report of this inquiry.

## 16.2 The special characteristics of transmission networks

The approach to planning and reliability setting for transmission networks needs to overcome a number of inherent problems that are not present in distribution networks.

* The need for NEM-wide planning. This reflects that transmission investments and reliability settings in one jurisdiction can affect other parts of the network in that jurisdiction, and that investments to address constraints in one transmission business’ network might be more efficiently made by another TNSP in another jurisdiction.
* The difficulty of observing the *latent* vulnerability of the transmission system to major outages. The majority of power interruptions that customers experience within the NEM result from faults or failures in distribution networks. In contrast, transmission networks typically deliver high levels of reliability. Indeed, transmission networks are said to be ‘inherently reliable’ (AER 2011e, p. 2). However, the low number and short duration of outages at a given time can lead to false optimism about the inherent reliability of the network over time. Moreover, the scale of transmission networks mean that any prolonged network failures can have widespread and very costly effects (box 16.1). This means that a transmission system must be planned to reduce the risks of future major network failures. In that respect, concerns about transmission network reliability are akin to those relating to the safety of major chemical plants or nuclear power stations, where the goal is to prevent major incidents.

These characteristics mean that it is not possible to rely on conventional incentive regulation alone to ensure efficient outcomes in transmission as:

* TNSPs are set up on a regional basis and will have a tendency to only consider NEM-wide effects (or lack thereof) of investments to the extent they influence their business — and may not sufficiently account for the costs of cascading failures or the efficient location of investments within the NEM as a whole
* privately-owned TNSPs will likely plan for reliability based on the commercial risks they face from having to compensate customers for outages, the loss of reputation and the possible loss of their license to operate. But they have limited liability. This weakens their incentives to make very large investments to prevent extremely high cost, low probability events, whose costs would not be fully borne by the business. It seems unlikely that a business’ board would make the same decisions to mitigate the risk of an event that produced costs equivalent to the business’ market value and one that produced costs 10 or 100 times the business’ market value (creating a wedge between privately optimal investment and socially optimal investment)
* privately-owned TNSPs have an incentive to put forward large investment proposals to the regulator for ex ante revenue determinations and to then delay investments necessary for reliability purposes in order to increase their profits. It is difficult to distinguish between profits acquired from strong efforts by the business to minimise the costs of achieving a given reliability standard (the goal of incentive regulation) and profits acquired from the inefficient deferral of investments needed for maintaining the inherent reliability (or indeed safety) of the network
* it may be difficult to hold TNSPs accountable for failures in network reliability since some factors affecting system reliability lie outside the control of the network business (such as major natural disasters).

To overcome this, Australian governments have set reliability standards for transmission networks, rather than relying exclusively on incentive regulation. (Setting reliability standards brings with it a number of other issues — see below.) These characteristics also mean that the best approach to ensuring efficient levels of reliability within distribution networks is not transferable to transmission.

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| Box 16.1 The significant costs of unreliable transmission networks |
| Some of the most significant blackouts worldwide have resulted from inadequate planning, maintenance or operation of transmission networks in response to one or several contingencies (Cepin 2011, p. 16).   * A blackout in Italy and Switzerland (28 September 2003) which affected 56 million people for 48 hours was caused by the operational overloading of a transmission line in Switzerland on a hot day, causing the line to sag and arc to the trees below. Power flows on the inter-network connections between Italy and its neighbours were cut in response to the failed Swiss transmission line, causing the Italian power system to collapse. * Moscow (25 May 2005) experienced a blackout estimated to have caused damage to the value of $US 70 million, which resulted from the failure of two electrical transformers that were reported to be ‘exhausted’. A combination of old and damaged transmission infrastructure and mistakes by operational personnel are said to have been the cause of the blackout * Severe outages in the United States and Canada (14 August 2003) that affected 260 power plants and tens of millions of people (some for up to eight days), and caused 61 800 MW of lost load, were caused by a combination of factors, including inadequate real time information available to network operators, failure to manage tree growth in easements, and a failure to manage network effects across interconnected regional networks. * 10 million people across Germany, France, Belgium, Spain and Austria were without power on 4 November 2006 due to errors of a transmission system operator in Germany, inadequate system security procedures, lack of information relayed to system operators in connected networks, and inadequate redundancy in the networks * In late July 2012, India faced massive system failures that cut power to around 670 million people or around 10 per cent of the world’s population (Yardley and Harris 2012). * The economic cost of outages in some African countries amounted to around 6 per cent of their annual GDP (Foster and Briceno-Garmendia 2010). |
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## 16.3 The broader planning context and economic regulation

Reliability standards are just one component of a complex system of economic regulation and planning (including the Regulatory Investment Test For Transmission (RIT-T) — box 16.2 and chapter 17). Decisions about how to regulate reliability will have broader implications for economic regulation and investment planning (and vice versa) (figure 16.1, which applies to jurisdictions other than Victoria).

Economic regulation is centred on the revenue determination process, undertaken using the building block methodology (chapter 5). The outcome of the determination is an overall estimate of the efficient cost of operating a network over the upcoming regulatory period. It sets a ‘pool’ of allowed revenue for the TNSP, but does not require that the TNSP build any particular project.

Figure 16.1 Parallel processes — economic regulation and planning

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| Figure 16.1 Parallel processes – economic regulation and planning. This diagram depicts two separate timelines, one for the economic regulation of transmission, and another for the transmission planning process.   At the start of the transmission planning process, some of the information from it can be used to 'feed into' the revenue determination, but the two processes are otherwise separate. |

*Source*: Based on AER (per. comm., 20 September 2012).

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| Box 16.2 The role and application of the RIT-T |
| The RIT-T, as currently designed, has a narrow focus and is not equivalent to the cost–benefit analysis that AEMO carries out in the lead up to a network augmentation in Victoria for several reasons (discussed further in chapter 17).   * Benefits do not have to outweigh costs for a project to ‘pass’ if the augmentation is being built to meet a reliability standard. * The transmission business intending to undertake a project carries out the RIT-T — not an independent party. * The details of alternatives canvassed in the RIT-T (and their costs and benefits) cannot be rigorously tested by parties outside the business due to the information asymmetries that exist between the business and all others (except perhaps where AEMO is involved in an inter-regional project). * Other parts of the regulatory regime, as well as state ownership, can create incentives that cause businesses to prefer options that diverge from a true NEM‑wide efficient solution. These incentives will not be overcome by any requirements in the RIT-T. * There is no substantive consequence for the TNSP from producing an inadequate RIT-T.   The RIT-T also has little role in the AER’s revenue determination process for transmission. The only role of any RIT-T is that the business must include any augmentation option that has passed a RIT-T in its aggregate capital expenditure (capex) revenue proposal. (In fact, many capital spending projects do not require a RIT-T and a RIT-T may not have been undertaken at the time the AER makes its revenue determination.) The AER does not approve specific investment projects, but instead provides a revenue allowance that leaves the business with choices about the timing and nature of its overall portfolio of investments over the regulatory period. Under that approach, the business must build to meet any specified reliability standards, but if it can undertake the projects to achieve those standards at lower cost, it can retain the savings as profits. In that sense, the term ‘Regulatory’ Investment Test is a misnomer as it may have very little bearing on the aggregate capex revenue proposal and may make little difference to what would have been built had the Test not been undertaken.  This is not to say that the RIT-T has no impact or should be discarded. Even if it does not overcome all information asymmetries between the prospective investor and other stakeholders, the Test is still able to shed some light on egregious examples of gold plating, or unjustified preferences for network-based solutions, or intra-jurisdictional preferences. Further, it provides a platform for public consultation of possible alternative options, especially for demand management options. However, as discussed in chapter 17, there are strong grounds for improving the Test.  The ‘RIT-T’ as undertaken by AEMO in Victoria has a different role. In this case, it is an independent cost–benefit analysis that determines the nature of the solution (which might not be capex) and the required revenue to meet those costs. To have the RIT-T play the same role in other jurisdictions, the AER or some other body could use an objectively appraised RIT-T to determine required investments, but to do so effectively would require impartial advice on specifications, options, timing, costs and network-wide needs. |
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As shown in figure 16.1, information from planning processes (which include Annual Planning Reports and the RIT-T) feed in to the revenue determination process, but is only used to inform the process, and is not used in a way that ‘locks in’ any particular investment. In the example in figure 16.1, information from the RIT-T for project A (which is due to be built in the regulatory period) is available as an input into the AER’s revenue determination. It is not possible to use information from the RIT-T for project B as it has not been prepared at the time of the determination. Instead, the Annual Planning Report would identify a network need, for which reliability standards are a key determinant, and the estimated cost of efficiently meeting the need would be included as part of the overall figure set by the revenue determination.

Under incentive regulation, there is no requirement that expenditure proposals used to inform revenue determinations actually materialise. At the end of the regulatory period, it is the actual spending — rather than that predicted by the RIT-T or the planning report — that is entered into the regulatory asset base (RAB) for the next revenue determination. Indeed, neither the RIT-T, nor the planning process, directly determine the revenue allocated to a TNSP by the regulator.

## 16.4 An efficient transmission framework?

Within the NEM, each jurisdiction has a separate planning framework for setting reliability standards for transmission businesses (table 16.1). The frameworks vary in the:

* type of standards applied and the level of discretion businesses have when meeting them
* level of standards, both within jurisdictions where standards in central business district areas are usually higher than elsewhere, and between jurisdictions even for similar types of location and customer
* body responsible for setting standards and the instruments used to specify them, including codes, licence conditions, legislation and Network Management Plans.

Each planning framework is a reflection of the historical development of the electricity network in the particular jurisdiction prior to the NEM. The final report of the Council of Australia Government (COAG) Independent Review of Energy Market Directions in 2002 noted that it was ‘very much aware of community and hence government sensitivity to issues of supply reliability’ (MCE 2002, p. 8), which underpinned the reluctance of governments to relinquish control of reliability settings in their networks.

Table 16.1 Transmission network reliability standards under existing planning frameworks**a**

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| State | Type of standard | Standard | Source of standard |
| NSW | Deterministic | N-1 everywhere, except central business district of Sydney where it is N-2 | Contained in Transmission Network Design and Reliability Standard for NSW from the Department of Industry and Investment |
| Vic | Probabilistic planning | Standard depends on the value of customer reliability (VCR) used at each connection point. The higher the VCR, the higher the standard (Melbourne central business district has the highest VCR) | Sections 50C and 50F of the National Electricity Law |
| Qld | Deterministic | N-1 everywhere but also includes generation assets (sometimes expressed as N-1-G) | Transmission Authority (licence) issued under S.34 of the *Queensland Electricity Act 1994* |
| SA | Expressed as deterministic, but changes are made based on probabilistic analysis | Six (revised to five from July 2013) categories of standard specified at connection points ranging from N to equivalent N‑2 for line and transformer capacity. Categorisation depends on VCR at that point | Electricity Transmission Code administered by the Essential Services Commission of South Australia with advice from the AEMO |
| Tas | Deterministic and performance based, according to limits on size of load interrupted or duration of interruption | For intact system:  N-1 for connections >25 MW  No asset failure will interrupt >850 MW  No credible contingency will cause unserved energy >3000 MWh  For network element out of service, no credible contingency to cause unserved energy of >18 000 MWh | Regulations recommended by Tasmanian Reliability and Network Planning Panel of the Tasmanian Energy Regulator and issued by Tasmanian Government |

a Deterministic standards and probabilistic planning are described in appendix F and VCRs are discussed in chapter 14.

*Source*: AEMC (2008a, pp. 171‑4).

While significant variations between jurisdictions exist, it is possible to assign each jurisdiction’s planning framework for setting transmission network reliability standards into one of three broad categories:

* deterministic standards in New South Wales, Queensland and Tasmania
* probabilistic planning in Victoria
* hybrid standards in South Australia.

There has also been considerable debate around a possible national framework for transmission reliability. The final report of the AEMC’s 2008 *Towards a Nationally Consistent Framework for Transmission Reliability Standards Review* found that most parties agreed with a national framework, but differed in how they envisioned that framework, and most particularly, its scope to allow jurisdictions to set their own standards (AEMC 2008a, p. 13).[[3]](#footnote-3)

### Approach to assessing frameworks for reliability settings

The efficiency of reliability standards within transmission planning frameworks can be assessed in four main ways, including:

* their impacts on a TNSP’s efficient choices about the various options for meeting reliability standards and their optimal timing
* whether the standards are set using a methodology based on the value consumers place on reliability (chapter 14)
* their administrative and compliance costs
* the extent to which a reliability framework allows businesses to make excess profits that do not reflect innovation or efforts to minimise costs (termed windfall gains by Grid Australia (sub. DR91, p. 18)).

A comprehensive assessment also requires taking into account the innate characteristics of transmission networks as spelt out in section 16.2.

These characteristics require that the efficiency of reliability planning frameworks is assessed with a NEM-wide perspective including by considering how well the frameworks:

* assist with the national operation of the grid
* encourage neutrality in choices between intra- and inter-regional network and non-network solutions
* deal with network effects and the possibility of cascading failures through the NEM.

A further consideration is the degree to which the frameworks need to incorporate auditing of facilities and processes in transmission networks to assess the latent and actual reliability of networks. This reflects the difficulties in using current reliability performance as a guide to latent reliability (section 16.2). Therefore, the only way of accurately assessing the inherent reliability of such networks is to:

* specify in some way what needs to be done to achieve a given level of reliability
* utilise methods to confirm that the transmission business is actually doing what it is supposed to have done.

In this sense, there is an analogy to safety management systems where a set of risk reduction measures are agreed, but then there is an auditing process to confirm that these are in place and operating as intended. Just as for major failures with a transmission network, it is not acceptable to simply wait and see if a major safety problem eventually arises.

The broad planning frameworks in the NEM are therefore assessed in terms of the following six broad criteria:

* *efficiency in investments* — under- and over-investment, along with optimal investment timing
* *efficiency of standards* — whether standards are set by determining the level of reliability that provides net benefits for customers
* *minimising administrative and compliance burdens* *—* costs imposed on market participants and regulators
* *minimising windfall gains* — whether it is possible to avoid windfall gains (or losses) from ex-ante revenue settings reliant on demand forecasts that may not eventuate
* *NEM-wide effects —* whether efficient investment location in the NEM is considered, along with other NEM-wide risks such as cascading failures
* *auditing compliance to ensure reliability and efficiency in the long run* — overcoming the inability to observe differing levels of reliability and ensuring that, where circumstances have not changed, proposed investments take place*.*

### Current approaches vary and have drawbacks

There are no easy solutions for ensuring efficient transmission reliability and planning in the NEM (and indeed this is the experience internationally). A fundamental reason for this is that, unlike for distribution networks, it is impossible to rely upon output measures and leading indicators to regulate reliability for transmission networks. All arrangements involve ‘big brother’ in one form or another, whether it be governments, a confederation of network businesses, or a single body, and there are compromises and judgments that must be made. A combination of transparency, accountability, consultation, specialist knowledge, independent decision-making and giving pre-eminence to consumer preferences are the essential components of a workable arrangement. However all arrangements have their pros and cons — there is no single perfect solution.

Assessments of the current approaches to transmission reliability across the NEM (appendix F) reveal a number of shortcomings of the current approaches.

* The deterministic standard systems used in New South Wales, Queensland and Tasmania provide weak incentives for TNSPs to adopt the cheapest solutions to address identified network constraints, are unlikely to identify efficient reliability standards and do not consider NEM-wide effects. However, they do have low administration and compliance burdens. Shifting away from deterministic standards towards a probabilistic cost–benefit framework could produce net present value savings in the realm of $2.2 billion to $3.8 billion over a 30 year period (appendix F).
* Victoria’s planner model performs well against many of the criteria. AEMO’s joint role as Victorian planner and operator means that NEM-wide effects are incorporated into investment decision making, albeit to a limited extent. The model should ensure that network constraints are resolved without over-investment, given independent cost–benefit analysis of prospective solutions to network constraints and the adoption of a probabilistic approach to standards. Contestability for separable investments (section 16.8) creates strong incentives for businesses to provide solutions at the lowest cost to customers. And for non-separable augmentations, once AEMO and the transmission business identify a required investment and have negotiated payments, cost savings by the business translate into higher profits, creating incentives for cost minimisation at the project level. However, the incentive regulations overseen by the AER do not apply for network augmentations in Victoria. Furthermore as a not-for-profit entity, AEMO does not face any direct financial incentives to find innovative ways of resolving network constraints without costly investments. On the other hand, it has no direct financial incentives to ‘gold-plate’ or defer necessary investments. Administration and compliance costs are also likely to be higher than the deterministic approach used in New South Wales, Queensland and Tasmania. Further, a number of improvements to the current probabilistic planning approach could be adopted.
* The hybrid approach used in South Australia is likely to reduce the risk of over-investment because of its use of probabilistic cost–benefit estimates for determining reliability standards. On the other hand, the approach may still risk some over-investment. First, it involves the translation of probabilistic estimates (based on Victorian customer reliability values) into deterministic standards that are expressed in excessively broad categories. Moreover, while the standards may rise as circumstances change, they cannot be revised down. Administration and compliance costs are likely to sit between the other approaches and, as in Victoria, AEMO’s involvement is likely to lead to NEM-wide effects being indirectly included in reliability planning.

None of the current approaches addresses concerns about auditing and compliance and, with the exception of Victoria, does little to minimise any windfall gains or losses from revenue determinations based on demand forecasts that may not eventuate. Outside Victoria, TNSPs have the incentive to attempt to justify inefficiently costly expenditures in order to meet reliability standards.

The assessment of the existing planning frameworks for transmission reliability against the criteria noted above provide a number of lessons for the development of a new national framework. These are outlined below.

### Efficiency of investments

* Commercially-orientated businesses with strong incentives to cost minimise (once committed to action rather than simply deferral) are more likely to identify efficient options for addressing a given reliability constraint. If these incentives are weakened, or business choices are influenced by other objectives, this will not necessarily be the case.
* Identifying which option should be adopted, how much it will cost, and when the project should occur is unlikely to be able to be undertaken with any level of certainty or efficiency years in advance of the project commencement. Technology changes, demand, external events and other cost drivers can all change significantly over the course of several years.
* Accurately specifying and costing projects close to their commencement, and approving the associated revenue allowances for projects based on this knowledge, can help deliver cost savings to customers.
* Competitive tendering of separable investments may reduce (net) costs and encourage innovation.
* Reliability can be enhanced using network and non-network solutions. Reliability settings (such as the type of standard) and regulatory settings (such as incentives) should not constrain or bias businesses in identifying the most cost‑effective solution and timing to deliver reliability benefits.
* Independent analysis of costs and benefits can provide greater assurance to governments and consumers of the value of investments.
* Transparency in assumptions and models helps generate confidence in investment choices.

### Efficiency of standards

* Levels of reliability are only likely to be efficient if they are identified within a cost–benefit framework.
* A cost–benefit framework requires a measure of the value customers place on reliability, which is a function of the costs they incur when an interruption occurs. VCRs that are robust, current, and disaggregated by relevant area and customer type should be the cornerstone of reliability settings.
* Incorporating VCRs in a planning context requires information on the probabilities of interruptions, and these probabilities must account for all foreseeable contingencies and their likely effects.
* The costs for transmission businesses of providing a reliable network and the costs to customers from interruptions change over time. Reliability settings need to be flexible to reflect the changing nature of the costs and benefits that underlie them.
* Planning standards and modelling should be transparent, with stakeholders able to query methods and results.

### Minimising administrative and compliance burdens

* Transmission businesses (and their owners) have a conflict of interest if they are responsible for both setting reliability standards and meeting them. Reliability settings for the NEM should be determined by an independent, non-conflicted, well-informed third party. Decision making about augmentation, replacement and maintenance should rest with TNSPs due to potential synergies in jointly planning these activities. There should, however, be external oversight of decisions for large projects. For smaller projects, there are grounds for TNSPs to undertake probabilistic analysis for determining the best way of meeting externally set customer-driven reliability standards without detailed external oversight of all augmentations due to the potential administrative costs involved.
* The process of setting reliability standards and for establishing efficient augmentation solutions should itself be as efficient as possible in terms of costs, timeliness and responsiveness.

### Minimising windfall gains

* A planning framework should avoid, where possible, large transfers that might arise from revenue determinations based on demand forecasts that do not eventuate while keeping the cost minimisation and innovation incentives of the incentive regulatory framework intact. Given the possible price and therefore consumption distortion effects of large transfers to TNSPs due to the large and lumpy nature of some augmentation investments, critical and contemporary reviews of major investment decisions should occur to minimise the potential for large windfall gains.

### Taking account of NEM-wide effects

* A planning framework should consider the costs and benefits of the effects that reliability settings in one area of the network can have on another (that is, network effects). As put by AEMO, a national planning approach ensures that interconnectors are viewed as part of the meshed intra-regional transmission networks that they connect (sub. DR100, p. 10).
* Desired levels of reliability should be delivered using a combination of intra-regional and inter-regional network and non-network solutions — that is, the net benefits should be maximised using a NEM-wide perspective.
* The risk of cascading failure across jurisdictions, the presence of network effects in increasingly interconnected transmission networks, and the importance of implementing inter-regional solutions to network constraints when beneficial to do so, suggests that the regulation of reliability in transmission networks in the NEM should be the responsibility of a NEM-wide authority, and not jurisdiction‑specific.
* This NEM-wide authority would be best placed to take responsibility for managing the national grid by developing and managing national transmission flow paths and reliability standards.

### Auditing compliance to ensure reliability and efficiency in the long run

* The difficulty of observing reliability outcomes in transmission networks is only addressed implicitly in the current frameworks. Economic regulations need to recognise the value of reliability and measure the latent and actual reliability of networks. If they do not, incentive regulations may lead to greater short-run profits at the expense of under-investment in reliability.
* Auditing compliance with reliability standards, including redundancy, and continuing to model the probability of interruptions, to the greatest extent possible, would be required to counter any such motivations, even with standards in place. Auditing whether networks meet deterministic standards would appear to be considerably easier than checking whether probabilistic criteria have been followed appropriately. In Victoria, this issue was addressed by appointing an independent planner (AEMO) with the appropriate resources and expertise. However, even in Victoria, there are grounds for auditing the delivery and performance of new investments, as well as maintenance and replacement projects.

## 16.5 The way forward

In the Commission’s judgment, the way forward for transmission reliability and planning frameworks in the NEM should be through some form of national framework that takes account of the characteristics identified above.

There has been a recent broad acceptance of the assessment that deterministic standards have an inherent potential to generate inefficient outcomes if not underpinned by a consideration of the value consumers place on reliability. This has led most stakeholders and governments, to varying degrees, to acknowledge the need to move to a reliability planning framework that is based on an economic cost–benefit framework — namely a probabilistic planning approach. For example, COAG stated that the national framework, developed by the AEMC should:[[4]](#footnote-4)

… incorporate values of customer reliability and differences arising from geographical location. (2012, p. 9)

Grid Australia also supported a national move to a framework where reliability standards were determined with consideration of their costs and benefits:

… there are many aspects of the Commission’s report that Grid Australia supports, including: … 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. (sub. DR91, p. 6)

This change, if adopted, should overcome inefficiencies in reliability standards. Indeed, in a high-level review of existing projects for 2012‑13 ($3 billion worth of projects) focusing on differences in investment timing between deterministic standards and those based on an economic cost–benefit framework, AEMO found that annual electricity bills for households in 2012‑13 could be at least $40 per customer too high:

AEMO compared the timing of augmentations proposed by the TNSPs, applying existing planning criteria requiring a specific reliability outcome, with investments that are timed to deliver a better price-service balance for customers. The high-level study into the benefits of an economic cost–benefit approach to network investment showed that there are significant savings that could be achieved.

The study indicated that 2012–13 electricity bills may be at least $40 per customer, on average, too high because current electricity investment is based on reliability in isolation of cost and the type of investment and would defer most augmentation timings.

AEMO believes that an economic approach is expected to deliver even greater savings to electricity consumers in the long term by providing more time to develop new generation and transmission solutions and technologies; and accommodate changes to demand profiles, acknowledging a more energy-conscious community. (sub. DR100, p. 5)

There is, however, some contention over the best way to implement a probabilistic planning approach. The principal debate relates to who undertakes the augmentation (and replacement) investment planning and puts forward the suggested options. (Under a probabilistic framework used to set standards the term ‘planning’ can become confusing — box 16.3.)

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| Box 16.3 The term ‘planning’ |
| Under probabilistic cost–benefit informed standards, what is meant by reliability ‘planning’ is not always clear. A significant degree of network planning must occur to identify the standards at a connection point level. This involves comparing the value of customer reliability with the costs of various investment options to achieve the most efficient reliability settings for the network.  Under such a system, certain planning activities are also conducted by TNSPs. To meet standards, TNSPs have to determine investment options, timing (subject to external review in some instances) and integration with other maintenance and replacement activities. These latter aspects have been termed ‘TNSP planning’ under the proposed model put forward in this chapter. |
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Grid Australia has argued that having TNSPs undertake network reliability planning subject to independently set standards would generate the greatest gains:

We maintain that electricity consumers are better served by adopting a nationally consistent arrangement involving transmission asset owners retaining responsibility for augmentation investment decisions in the shared transmission network. (trans., p. 289)

The AEMC also supported this view, stating that it:

… considers that financial incentives are likely to provide the most robust and transparent driver for efficient decision-making, as efficient outcomes can best be promoted by aligning the commercial incentives on businesses with the interests of consumers. (sub. DR89, p. 7)

AEMO agreed that arrangements along the above lines are likely to be a substantial improvement on the current situation (sub. DR100, p. 5). Nevertheless, AEMO’s preferred position (articulated most fully in its first submission (sub. 32)) is that planning should be undertaken by a NEM-wide central planner to ensure efficiency across the entire network:

Australia’s transmission regulation and planning regime must optimise network development on a national basis to deliver the most efficient response to the challenges of the future. … Independent planning coupled with the competitive provision of network services will deliver the most efficient outcomes. (sub. 32, p. 4)

In the Commission’s view, the most efficient model would draw on both the original AEMO and the new Grid Australia/AEMC approaches (a summary of the existing and proposed models is provided in table 16.2). Transmission businesses would be free to undertake augmentation (and replacement) investment planning subject to independently set national reliability planning standards, but with all planning underpinned by probabilistic cost–benefit assessments. This model corrects some of the deficiencies of the current approach in Victoria and that of the proposed AEMC’s hybrid[[5]](#footnote-5) and Grid Australia (sub. 91, pp. 10‑38) models. The relative costs and benefits of the proposed approaches, along with existing reliability planning models are assessed in appendix F.

### The Commission’s national transmission probabilistic reliability standards model (the ‘PC model’)

The Commission’s proposed model — set out in greater detail in figure 16.2 —could overcome many of the issues identified with the current reliability planning approaches. The PC model seeks to improve national oversight of transmission planning, making TNSPs more accountable (a concern raised by AEMO (sub. DR100, p. 5) Grid Australia (sub. DR91, p. 10); and SP AusNet (sub. DR99, p. 3)).

Table 16.2 Current and proposed transmission planning models

|  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- |
|  | Deterministic standards model (NSW, Qld & Tas) | AEMO planner model (Vic) | Hybrid standards  model (SA) | AEMC hybrid  model | Grid Australia’s  model | PC model |
| Type of reliability standard or planning? | Deterministic | Probabilistic planning | Probabilistic planning informed deterministic standards (applied to 6 connection point categories) subject to no downward revision requirements | Hybrid standards for connection points | Probabilistic cost–benefit standards expressed deterministically | Probabilistic cost–benefit standards expressed deterministically or probabilistically |
| Standards contained in? | State-specific regulations and licence conditions | Not specified but most likely reliability to become a national function | Electricity Transmission Code administered by Essential Services Commission of South Australia with advice from AEMO | National template and/or jurisdictional instruments. Reliability to remain as a state and territory function | Reliability to become a national function | Reliability to become a national function |
| Who sets the standards? | Jurisdictions | AEMO | Jurisdiction | Jurisdictions with input from expert advisor | Independent body in consultation with consumer representatives and stakeholders | AEMO in consultation with transmission businesses |
| Who makes augmentation investment decisions? | Transmission businesses | AEMO | Transmission business | Transmission businesses | Transmission businesses with oversight of AEMO and AER | Transmission businesses with oversight of AEMO and AER |

(Continued next page)

Table 16.2 (continued)

|  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- |
|  | Deterministic standards model (NSW, Qld & Tas) | AEMO planner  model (Vic) | Hybrid standards model (SA) | AEMC hybrid model | Grid Australia’s  model | PC model |
| Process for planning or setting standards? | Set at level deemed appropriate by jurisdictional standard setting body | AEMO probabilistic planning process | Historical deterministic levels with upwards revision based on probabilistic analysis | AEMO to develop national template. Standards to be ‘informed’ by jurisdictionally appointed body | Independent body to apply best practice probabilistic cost–benefit assessment in consultation with consumer representatives and stakeholders | AEMO probabilistic planning process, based on ABS data, peer reviewed and designed to be international best practice |
| How is revenue allocated? | AER five yearly revenue determination process | Negotiation between AEMO and transmission business before start of non‑separable projects. Contestability for separable projects. | AER five yearly revenue determination process | AER five yearly revenue determination process | Combination of AER five yearly revenue determination process and contingent projects subject to ‘trigger’ criteria | Improved RIT-T process for large projects above threshold before start of project. AER five yearly review for below threshold projects |
| Independent cost–benefit analysis or RIT-T? | Businesses to conduct RIT-T (net costly augmentations possible if justified to meet reliability standards) | Independent cost–benefit analysis | Businesses to conduct RIT-T (net costly augmentations possible if justified to meet reliability standards) | Businesses to conduct RIT-T with scrutiny by AEMO | Businesses to conduct RIT-T with scrutiny by AEMO and oversight by AER | Business to conduct cost–benefit analysis through improved RIT-T with scrutiny from AEMO whose advice takes presumptive force and approval by the AER |
| Last resort planning power | AEMC | AEMC | AEMC | AEMO | AEMO | AEMO |

#### AEMO sets standards using a probabilistic approach

On a NEM-wide basis, AEMO should undertake probabilistic cost–benefit analysis using VCR estimates obtained from the ABS (recommendation 14.2) and input from distribution businesses on demand forecasts to develop a reliability standard at each connection point. The standards could be expressed in the same manner as existing deterministic standards (the N-x formulation). Alternatively, they could be expressed in other ways, such as the probability-weighted quantity of electricity at risk — the approach taken by Victorian distribution business (AEMC 2012k, p. 81). Distribution businesses should also be consulted on standards for the connection points that link their network with the transmission grid.

AEMO should revisit this analysis periodically. AEMO’s probabilistic analysis as currently used in Victoria, and to a lesser extent in South Australia, should be improved to include the following:

* Greater scrutiny over its process, through regular reporting of modelling parameters, assumptions and results, and data inputs to the AER. This would include releasing details of the estimated amount of load customers were willing to lose at any connection point, based on the estimated VCR, before any reliability increase or augmentation needed to be considered (AEMO, sub. DR100, p. 5). Periodic review would also be appropriate to ensure that the standard setting framework was delivering optimal outcomes in accordance with the National Electricity Objective (NEO).
* An enhanced process for probabilistic analysis — assessed through periodic peer review — to ensure that the analysis represents international best practice. One of the first steps is to identify the deficiencies in the data collected by network businesses and AEMO, and establish the required collection and reporting processes.
* The use of disaggregated VCR estimates, including by geographical location, customer type and interruption duration. Given the difficulties with estimating an accurate VCR and the fact that VCR is an aggregate of the differing preferences of many customers, adopting a VCR that is at the higher end of the reasonable range of possible values would be sensible. The ABS would be the most appropriate body to undertake the research required to reveal accurate VCRs (recommendation 14.2). The VCR surveys would be undertaken periodically, with AEMO’s annual probabilistic analysis and planning based on extrapolated data for periods between the survey dates.

Figure 16.2 The PC model

|  |
| --- |
| ABS Survey  of VCR  (  conducted  periodically  )  Stakeholder  input  (  TNSP  costs  ,  consumer  reps  ) (  conducted  periodically  )  Demand  forecast data  (  updated  annually  )  Optional firm  access  contracts  (  longer term  )  Probabilistic modelling  Review  /  transparency  reporting  **AEMO planning**  **/**  **standard setting process**  National Transmission Network  Development Plan  (  updated annually  )  Inputs into contingent  review decision process  TNSP identifies which standards can only be met by  large  (  contingent  )  projects that are above threshold  (  specific projects identified  )  Funded by AER revenue allowances  Revised or approved investments made  .  AEMO directed investments under planner of last resort powers  .  TNSP planning  Ex post review of investments that are over revenue allowance  .  Auditing of investments including timing  (  matched against national transmission plan  ).  **AER**  Re  -  expressed as deterministic  or probabilistic standards  (  set for  5  year regulatory  period  )  TNSP identifies which standards can be  met by projects that are below threshold  (  specific projects not necessarily identified  )  AER to review taking into account  AEMO advice  .  Probabilistic planning used for cost  –  benefit assessment with stakeholder  input that needs to be approved by  AER  (  expanded RIT  -  T  )  **AER**  **TNSPs**  **AER** |

#### An annual National Transmission Network Development Plan would guide TNSPs and the AER

The probabilistic planning approach that AEMO uses to establish reliability standards in the NEM should also form the basis of the annual National Transmission Network Development Plan (NTNDP). This would provide a critical input into the planning undertaken by TNSPs and in the assessments made by the AER. The probabilistic modelling would be undertaken in depth every five years, but with annual updates based on more simple analysis to test whether standards are too low or high at critical connection points.

#### Investment decision-making would depend on the scale of the investments

Once standards are set, TNSPs should undertake reliability planning of their networks with reference to the NTNDP. This would have two components.

Identified augmentation and replacement projects less than a certain threshold (see chapter 17 for details on what might be an appropriate threshold) would be undertaken by the TNSP without direct AEMO or AER oversight. The required revenue to fund these projects would be drawn from the aggregate revenue determination made by the AER at the start of the regulatory period. The TNSP would not be obliged to specify these projects in detail at the time of the revenue determination. Instead, as is currently the case, for any given regulatory period, the TNSPs would propose a set of capex and operating costs (opex) necessary to supply reliable power over the next five-year period, without any commitment to undertake any specific projects that might form part of its revenue proposal. However, at any time, it would be obliged to be able to demonstrate that it met the reliability standards translated from AEMO’s probabilistic analysis.

In contrast, the process for approving identified augmentation and replacement projects greater than the identified threshold would draw on aspects of the current arrangements for so-called ‘contingent’ projects.[[6]](#footnote-6) Investments would be assessed through an improved RIT-T process and revenue to fund the project would be determined and provided outside the general revenue determination process (as is currently the case for network augmentations in Victoria).

#### An improved RIT-T process

The improved RIT-T process would require a full probabilistic cost–benefit analysis of the investment, including an assessment of network and non-network options. The RIT-T would only be approved by the AER if projects were shown to generate net benefits estimated using current information (a shift from the process-based approval under the existing RIT-T). The AER would also determine the allowable revenue on a project-by-project basis. As the RIT-T is a full cost–benefit analysis, it would effectively reassess the reliability standard for that part of the network.

It would be important to mirror the current risk sharing arrangements present in general revenue determinations to avoid cost-shifting between large projects and those covered by the general revenue allowances. Accordingly, if a business were able to undertake a large project at less than the negotiated cost, then it would be able to keep a proportion, but not all, of the gains (as is the case in general revenue determinations — chapter 5). Similarly, if a TNSP were to spend more than the negotiated amount for a large project, it would be penalised by a share of the cost overrun. TNSPs would also be potentially subject to an ex post review process by the AER if its expenditures exceeded those set out in the approved RIT-T. In the case where the AER identified investments that exceeded the approved capital and were built too early (for example, an investment that was built to a higher capacity than would have been required to efficiently meet the constraint), inclusion of the higher capital costs in the RAB should be deferred until such time that the investment would have been beneficial. For cost overruns, only efficient investment expenditure would be included in the RAB.

The AER must also accept the advice from AEMO about the need for, timing, scale, choice and costs of the project, unless the TNSP could provide sufficient evidence to refute its finding (that is, AEMO’s advice would have presumptive force). Projects approved through the improved RIT-T process would have an allowed revenue approved for the current regulatory period, with the value of the assets (less any depreciation) rolled into the RAB at the commencement of the next regulatory period (provided there were no inefficient cost overruns disallowed by an ex post review — see chapter 17 for more details on the improved RIT-T process).

#### A safety valve to ensure a reliable system

AEMO should become the planner and procurer of last resort and seek to augment the transmission network if it identified investments to meet reliability standards that were *net beneficial* for the NEM and were not being undertaken by the regional TNSPs. AEMO would have the power to direct a TNSP to act or seek to procure from the market an augmentation to satisfy any reliability constraint identified. The AER would be the arbitrator of any disputes between TNSPs and AEMO.

### The costs and benefits of the proposed approach

The proposed PC model is *designed* to score well against the assessment criteria for an optimal reliability framework (table 16.3).

Table 16.3 How proposed transmission reliability planning models score against the assessment criteria

Indicative NEM-wide result

|  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- |
|  | Efficiency of investments | Efficiency of standards | Minimising admin and compliance costs | Minimising windfall gains | Taking account of NEM-wide effects | Auditing compliance to ensure reliability and efficiency |
| AEMC  model |  |  |  |  |  |  |
| AEMO planner model (Vic) |  |  |  |  |  |  |
| Grid Australia model |  |  |  |  |  |  |
| PC  model |  |  |  |  |  |  |

*Source*: Based on analysis in appendix F and this chapter.

* *The model reduces the risk of under-investment for large reliability driven investments.* Several factors are pivotal in achieving this outcome. First, as TNSPs no longer access revenue at the start of a review period for large projects, there are no benefits from deferring large investments needed for reliability purposes. The enhanced RIT-T approach would provide flexibility to shift the timing of investments when circumstances change, as the standard itself, and therefore investment need, is reviewed just prior to project commencement. Only net beneficial projects, assessed with current information, would be approved — a form of a ‘real options’ approach to planning.[[7]](#footnote-7) Second, explicit standards provide clear guidance about what standards must be met. Finally, AEMO’s last-resort planning and decision-making powers provide a safety valve in case of significant mistakes by TNSPs. An Achilles’ heel of the model may be that it does not necessarily guarantee sufficient investment for projects below the threshold. However, the TNSPs would still be obliged to meet standards and to meet the costs of system failures if it did not do so.
* *Standards are efficient*. The determination of standards based on probabilistic cost–benefit analysis at the connection point minimises the ‘lumpiness’ of applying standards compared with models that make use of a limited number of connection point categories to which standards are uniformly applied (as exists in AEMC’s proposed model and in South Australia’s current approach). It therefore reduces the risk of inefficiently high reliability investments. Further, standards would be allowed to rise or fall over time depending on VCR, overcoming the issues that exist with South Australia’s hybrid model. Looked at in isolation, the PC’s model *appears* to permit some inefficiency in standards for the smaller projects. Such small projects are not subject to the contingent projects regime and so do not entail full cost–benefit analysis using updated information at the time close to project commencement (below). However, a major reason for having a threshold in the first place was in recognition of the fact that applying a full cost–benefit analysis to every project would involve excessively high transactions costs. Accordingly, from a broader perspective, the standards would still be efficient.
* *Incentives to cost minimise and innovate are maintained*. For projects under the chosen threshold, there are strong incentives for a profit-motivated TNSP to seek the least‑cost solution to meet the standard. For projects above the threshold, the public RIT-T process should help identify innovative solutions, and as revenues are then determined for specific projects, profit-motivated TNSPs have strong incentives to cost minimise. For both, the retention of planning responsibilities with TNSPs enables them to capture any economies of scope that come with combined augmentation, replacement and maintenance planning. Grid Australia claimed that this was a significant benefit (sub DR91), though it provided little evidence about the magnitude of those benefits. Moreover, TNSPs may also be better placed to implement ‘firm access’ requests under the optional firm access (OFA) model (which is also subject to regulatory controls — chapter 19) as they would be able to manage both market based (generator led) and reliability required investments. (The AEMC has suggested that if OFA is adopted, generator led investments will likely reduce the amount of reliability planning undertaken in the NEM (sub. DR89).)
* *The opportunity for windfall gains is minimised*. Large lumpy projects over the threshold, for which timing is critically affected by factors such as forecast demand that is subject to error (Grid Australia, sub. DR91, p. 18) are assessed independently, with updated information prior to commencement. This means that TNSPs are not provided revenues upfront for projects that are delayed or even deferred to the next regulatory cycle. However, limited risks remain for below threshold projects. This could potentially be overcome by ‘clawing back’ any windfalls gains (or correcting for losses if projects need to be brought forward) (box 16.4) through an efficiency benefit sharing scheme. An efficiency benefit sharing scheme is now permitted by the Rules, but is yet to be developed by the AER (AEMC 2012r, p. v and chapter 5).
* *NEM-wide effects are considered*. NEM-wide effects are incorporated through the NTNDP, the standards themselves and AEMO’s role as planner and procurer of last resort. Further, with stronger incentives created by the recent Rule changes, businesses are more likely to seek out cheaper inter-regional options than previously. However, the PC model does not guarantee that the smaller investments made by TNSPs would fully account for NEM-wide effects. In that sense, it is possible that the PC model would provide a more ad hoc set of solutions to network effects than that of a centrally planned model. However, there are also offsetting advantages of relying more on local knowledge and the benefits of the synergies with general operating and maintenance decisions for smaller projects. This suggests that, on balance, the PC model would not result in significant costs associated with its slightly weaker consideration of NEM-wide effects.
* *But there are some additional administration and compliance costs.* The PC model requires AEMO to plan nationally when setting the standards, provide input into the RIT-T process and act as the planner and procurer of last resort. There would also be a number of additional costs in embedding the necessary ‘checks’ in the system to ensure efficient investments take place and in funding AEMO to undertake its significantly expanded role. These include:
* the ongoing enhanced development of both annual NTNDPs and NEM-wide cost–benefit probabilistic modelling to set standards by AEMO
* the additional review of proposed TNSP investments by the AER and AEMO as part of the ‘contingent projects’ approach to investments over the threshold
* however, removing large projects from the revenue determination process may generate some savings
* the requirements placed on AEMO to discharge its responsibilities as planner of last resort.

|  |
| --- |
| Box 16.4 Minimising windfall gains or losses for below threshold projects |
| Grid Australia (sub. DR91, pp. 18‑9) and SP AusNet (sub. DR99, p. 5) suggested that a scheme to ‘claw back’ allowed revenues provided for projects which did not go ahead (or were deferred) due a divergence of actual demand to that which was forecast at the time of the AER revenue determination would eliminate windfall gains. The same scheme could be used to make up for losses related to additional projects that were brought forward in instances where demand increased.  The approach would be an attempt to determine the windfall gain (or loss) element related to demand changes from that of the efficiency savings made by a profit motivated business (through a re-evaluation of the revenue determination using actual instead of forecast demand). This would be done at the end of the regulatory period with windfall gains returned to the AER (or additional revenues to cover losses approved).  Similar approaches have been used elsewhere, both in Australia and other countries. For example, the Essential Services Commission Victoria has applied an analogous approach to the gas sector where windfall gains were netted out allowance for efficiency savings. Under the arrangements, an ‘efficiency carryover mechanism’ is used to provide financial rewards (or penalties) for both opex and capex efficiency gains relative to the benchmarks (ESC 2008, p. 570). This is adjusted to take account of difference between forecast and actual work undertaken due to changes in demand (for example, new connections) (ESC 2008, pp. 573‑4). The UK Office of the Gas and Electricity Markets also makes use of adjustments based on actual versus forecast demand in its uncertainty mechanisms to aid in determinations of the efficiency incentive rate it provides to network businesses (Ofgem 2012, p. 31).  The Commission understands that with the recent Rule changes (AEMC 2012r, p. v), the AER could pursue such an approach under the range of existing tools used to provide incentives to reduce capital expenditure. |
|  |
|  |

Grid Australia (sub DR91) has also suggested that a model with explicit standards makes reliability planning more transparent and TNSPs more accountable for any breaches in reliability requirements than the central planning model used in Victoria. Such a model avoids concerns over who is liable if an outage occurs. However, in terms of transparency, both approaches are similar if modelling is made public and auditing takes place. As both models are underpinned by probabilistic assessments of costs and benefits, knowing ‘*why the standard (or investment) is what it is*’ will be the same and relies on AEMO making public its modelling. Knowing ‘*what the standard is*’ and ‘*whether the standard is being met*’ is informed by public reporting of investment auditing.

Applying the proposed planning framework will also generate benefits for investment and replacement projects not related to reliability. The ‘contingent project’ approach provides greater incentives for TNSPs to pursue ‘market driven’ projects, which may get delayed under the existing arrangements. Under incentive regulation alone, networks have the incentive to propose market driven investments and to have the associated revenues included in their revenue allowances, but then defer these projects. This arises as external parties generally have difficulty in assessing whether this deferral was efficient or not (they cannot be judged against specific standards). Under a contingent project approach, no such incentives exist as the network can only access the revenue at the commencement of a project.

#### Is the PC model robust to changing circumstances?

The regulatory solutions to the problems posed by reliability requirements depend on other regulatory settings and the behaviour of the network businesses. The Commission considers that its model is relatively robust under different regulatory contexts.

However, a major caveat to the above conclusion exists. It is critical that the right governance model be chosen to implement the PC’s model. In particular, the benefits of the PC’s model would be reduced were the states to appoint their own regional planners to undertake the probabilistic analysis (as recommended by the AEMC for its own model) because:

* the administrative and compliance costs would be high given duplication
* there would be questions about different methodologies (and therefore accountability) and the quality of the analysis
* the consideration of NEM-wide effects would, at best, be clumsy
* there would be concerns that political preferences, which are rarely accurate approximations of true VCRs, and can vary frequently, could be brought to bear on the standards.

Accordingly, the Commission considers that any probabilistic analysis and general planning be NEM-wide and undertaken by one body (preferably AEMO).

### Transition costs in implementing the reforms

Moving to the PC model will impose some transition costs on the jurisdictions and electricity market participants. These will relate, in part, to the pace at which reform occurs.

The regulatory determination periods place some natural constraints around the implementation of any reforms to transmission reliability planning. Regulatory periods vary across the NEM, with the next determination period being 1 July 2013 for ElectraNet in South Australia, compared with 1 July 2017 for Powerlink in Queensland.

These arrangements are further complicated by the presence of the latest Standing Council on Energy and Resources (SCER) directed review being conducted by the AEMC (SCER 2013b). This report is not due to be completed until November 2013 and, if agreement is reached at SCER on its recommendations, an implementation plan (but absent any Rule changes) would not be considered until mid-2014.

Both these factors would delay the implementation of any reforms to transmission reliability planning arrangements. Due to these and other concerns over the timeliness of reform within the NEM, the Commission has made a number of recommendations, which would accelerate the reform process (chapter 21). However, even if the decision-making processes were overhauled and accelerated, state and territory governments and the relevant TNSPs would still have an extended period to plan the implementation of the new recommended framework. The proposed reform will not be a disruptive and sudden shock to existing planning arrangements for most jurisdictions, and therefore there should be few transition costs.

In Victoria, the desired transition timetable is more complex than some others. On the one hand, Victoria’s reliability framework is already close to that recommended by the Commission and therefore the degree of regulatory change for Victoria is much less than other jurisdictions. On the other hand, Victoria might be reluctant to shift given the tradeoff between the resulting smaller benefits of reform for that State and any transitional costs. Nevertheless, given the long-run benefits, there remain strong grounds for Victoria to move to the Commission’s proposed framework, but there is a weaker imperative to fast-track reform in that State. The Commission’s proposed timetable for reform in this area is set out in chapter 21.

## 16.6 Delivering reliability in the shorter term

Augmenting networks according to a detailed planning process is one facet of network quality. Network businesses also need to:

* operate their networks safely
* maintain their networks in good working order and make repairs
* deal with possible causes of faults where possible, such as removing vegetation growing close to equipment
* respond quickly to restore supply when an interruption occurs.

#### Service Target Performance Incentive Scheme

The AER developed the Service Target Performance Incentive Scheme (STPIS) for transmission to encourage transmission businesses to maintain network reliability through actions other than building in redundancy.

The STPIS sets targets for:

* circuit availability — the proportion of time that all elements of the network are working and available
* the frequency of outages
* average outage duration
* market impact — designed to encourage businesses to improve availability at times, and on those elements of the network, that are most important to determining spot prices.

Businesses incur penalties (rewards) if they perform below (above) their targets, which are calculated as a percentage of their maximum annual revenue (MAR), referred to as ‘revenue at risk’. The maximum reward or penalty for the three service components of the STPIS in total is 1 per cent of MAR, while it is 2 per cent for the market impact component. The targets, weights for each criterion, and total revenue at risk are unique for each business with rewards and penalties not required to be symmetric. In general, targets are set using an average of historical performance over the previous five years, although businesses can propose an alternative target to the AER.

Following a review of the STPIS for transmission businesses, the AER has made amendments to the scheme. These include an additional network capability component to encourage transmission businesses to ‘deliver benefits through increased network capability, availability or reliability through the development of one-off projects that can be delivered through low cost operational and capital expenditure’ (AER 2012r, p. 9).

The AER has also decided to include a:

* circuit outage rate parameter as part of the service component to measure the number of unplanned faults on transmission networks
* reporting only parameter to measure the number of times that protection and control equipment fail to operate correctly.

The amendments are intended to strengthen the incentives contained in the STPIS and encourage more efficient use, operation and augmentation of the network.

The AER has suggested that the new measures are lead indicators of possible future reliability issues. If so, such indicators would provide useful information to AEMO in assessing current levels of reliability in the NEM when setting standards.

Transmission businesses appear to have responded positively to the incentives offered under the STPIS (AER 2011e), suggesting that the costs of improving performance have been less than the rewards available. This type of incentive regime, in theory, removes the need for benchmarking these elements of reliability performance, because as long as the potential rewards (penalties) are large enough, a profit-motivated business would have an incentive to search for efficiency gains to meet the reliability targets. However, if rewards were too high, customers would pay more for reliability improvements than they cost to achieve.

In the context of the PC’s reliability and transmission planning model, the STPIS would become an important driver of reliability performance for several reasons.

* Probabilistic planning to set standards is likely to reduce redundancy specifications in at least some parts of the NEM (including reducing the potential for overbuilding), which might increase the risk of more and longer interruptions to supply unless businesses manage their maintenance, operation and response outcomes in an appropriate way.
* Less redundancy in the network might lead to increased congestion on some lines at certain times, especially if the business is carrying out maintenance on that part of the network, which would increase the relative importance of the market impact measure.

Any future changes to the STPIS to reflect the increasing importance of operational, maintenance and performance outcomes under a new national planning framework should consider the evaluation criteria already used by the AER in its recent review (2011e, p. 12) to ensure that businesses retain the incentive to provide a reliable network up to the point that it is efficient to do so.

#### Dynamic and static equipment ratings

Transmission businesses determine how much power can flow through their equipment at any time. They ensure that they meet the network security standards set out in the Rules by specifying the maximum load that a line or other equipment can carry (so-called equipment ratings).

Network elements can carry different loads in different ambient conditions. In hot, still weather, lines heat up more quickly and droop further, increasing the likelihood of arcing.[[8]](#footnote-8) To recognise that, on average, safe loads can be higher in winter than in summer, and at night than in the middle of the day, transmission businesses vary the maximum load (rating) that lines and equipment can carry. This is currently achieved in two ways.

Static ratings set out the loads that lines or other equipment can carry at different times of the day in different seasons and in some cases, in specific months. These ratings are based on the ambient conditions expected to occur (not those that actually occur) at each time, plus a margin of error for unseasonably high temperatures.

Dynamic ratings measure the ambient temperature around equipment and sometimes the wind speed, and relay this information to operators so that the maximum safe load for that specific point and time can be utilised. On average, lines and equipment with dynamic ratings are used to a higher capacity than those with static ratings. For example, a line with a static rating on a cool, windy night in summer will likely have spare capacity on it.

Ratings that fail to utilise this dynamic approach can be costly where they lead to:

* higher cost generators being dispatched along other parts of the network due to lines reaching their maximum static (but not dynamic) load
* network businesses augmenting their networks earlier than necessary because lines are running close to their specified maximum static (but not dynamic) loads.

Static ratings may lead to significant underutilisation of network assets compared with dynamic ratings (with some estimates suggesting that utilisation for some assets could be improved by around 65 per cent for a period of time without any loss of safety). This appears to be one area where large cost savings could be made without sacrificing reliability outcomes.

There has been some adoption of the technologies required to implement dynamic ratings, but the take up has been uneven across the NEM. Victoria has the highest proportion of its network operating with dynamic ratings. It is not clear why the rate of adoption of dynamic ratings has been slow, although the distortions created by the incentives in the regulatory regime (chapter 5) could be one explanatory factor.

## 16.7 Changes to transmission reliability

As the discussion above illustrates, there are many complex issues involved in the setting of reliability standards, their application in the transmission planning process, and other influences on the delivery of reliability in the short term.

Unsurprisingly, there is no single, ‘silver bullet’ solution. Accordingly, the Commission’s proposed improvements for transmission reliability (set out below) span a range of measures, including technical settings of reliability, responsibility for and transparency in planning and interaction with incentive regulation. These should not be considered on an individual basis, but rather taken as a package of reform for transmission reliability.

Recommendation 16.1

***The Standing Council on Energy and Resources should, in consultation with the Australian Energy Market Operator and the Australian Energy Market Commission, develop a National Electricity Market-wide transmission reliability framework in which reliability settings would be determined by customer preferences (recommendation 14.1).***

This framework should replace all jurisdiction-specific transmission reliability settings.

Recommendation 16.2

A new approach to transmission reliability planning should be adopted. The Australian Energy Market Operator (AEMO) should carry out probabilistic   
cost–benefit transmission planning for all transmission networks in the National Electricity Market in order to set reliability standards and demand forecasts at each connection point. AEMO should:

* use Values of Customer Reliability (as obtained through recommendation 14.2)
* use best practice probabilistic processes in its cost–benefit analysis of efficient standards
* make public all methodologies, parameters, data and other inputs used in the analysis
* work closely with each of the transmission companies concerned to make sure that their experience and input is fully understood and, where mutually agreed, appropriately incorporated into the analysis
* work closely with the relevant distribution companies in determining demand forecasts and cross checking the reliability settings for each connection point
* use its best estimate of peak demand forecasts, having sought input from all relevant stakeholders
* set standards reflecting the probabilistic analysis at the connection point level throughout the National Electricity Market.

Recommendation 16.3

The regional transmission network service providers should plan necessary augmentation and replacement investments with reference to the reliability standards set by Australian Energy Market Operator (AEMO) and the National Transmission Network Development Plan. This should have two components.

For augmentation and replacement projects below a threshold value:

* the regional transmission network service provider should submit plans and seek funding for investments to meet reliability standards as part of the ex ante revenue determination process with the Australian Energy Regulator (AER), but could, ex post, decide to solve reliability problems in any way it decided was most efficient.

For augmentation and replacement projects above a threshold value:

* the regional transmission network service provider should submit details and seek funding of investments to meet reliability standards as part of the improved Regulatory Investment Test for Transmission process under which the AER would approve the allowable expenditure, having taken advice from AEMO.

At the next regulatory reset, the actual capital spent on such projects should be included in the transmission business’s Regulatory Asset Base, subject to any ex post review if expenditures exceeded the allowable revenues as set out in the approved Regulatory Investment Test for Transmission. If an ex post review identified instances of over‑expenditure linked to inefficiently timed capacity increases, inclusion of the over-expenditure in the Regulatory Asset Base should be deferred until such time that the additional capacity would have been net beneficial. For cost overruns, only the efficient investment spend should be included in the Regulatory Asset Base.

Recommendation 16.4

The Australian Energy Regulator should ensure that, in the Australian Energy Market Operator’s role as a transmission standard setter, its public reporting and planning processes are adequate, transparent and meet the National Electricity Objective.

Recommendation 16.5

The Australian Energy Market Operator (AEMO) should review and, where necessary improve, the technical aspects of its probabilistic processes, particularly those relating to low-probability, high-risk events. In undertaking the review, AEMO should closely consult with network businesses and seek independent peer review of its technical methods.

Recommendation 16.6

Where necessary, the Australian Energy Market Operator should assist the Australian Energy Regulator in its compliance and auditing of transmission networks, to ensure that the agreed projects are completed, appropriate maintenance and operational standards are being achieved, and intrinsic network reliability is maintained.

Recommendation 16.7

The Australian Energy Market Operator (AEMO) should act as the planner of last resort where it considers that underinvestment could expose the network to serious reliability problems, with the right to direct investment should AEMO believe that not to do so could seriously compromise the reliability of the National Electricity Market. The Australian Energy Regulator would act as an arbitrator in any disputes.

Recommendation 16.8

The Australian Energy Regulator should review the Service Target Performance Incentive Scheme for Transmission to ensure the incentives and targets are consistent with the recommended National Electricity Market-wide reliability framework.

Recommendation 16.9

Transmission businesses not already using dynamic capacity ratings on all critical equipment should transition to this approach.

## 16.8 Contestability in new connections and other separable transmission investments

Currently, Victoria is the only jurisdiction that has introduced contestability into some augmentations of the transmission network — those of separable investments likely to cost over $10 million.[[9]](#footnote-9) (The future introduction of the OFA arrangements[[10]](#footnote-10) discussed in chapter 19 may introduce an element of competition between TNSPs that could compete to provide firm access to existing generators.) Contestability in the provision of separable investments has been seen as a means to reduce market power and overcome information asymmetries:

Transmission services need to be procured efficiently given their high costs. Where possible, this should be achieved through competitive tendering of the construction and ownership of major network investments. Effective competition has the capacity to reduce market power and overcome information asymmetry problems. (AEMO, sub. DR100, p. 6)

Most concerns expressed relating to TNSP market power and information asymmetries have been raised in the context of new connections — a subset of separable investments. This section examines the case for introducing contestability into new connections (with possible extension to other types separable projects, such as interconnector investments, if benefits are proven) and recommends a model for this to occur throughout the NEM.

### New connections to the transmission network

New generator connections to the network are generally regarded as additions ‘outside’ of the shared network. However, they also often require upgrades to the shared network itself.

Concerns have been raised about the possibility for TNSPs to exploit their market position in dealings with the connection of new generators to the NEM. For example, the Clean Energy Council argued that:

… some areas where new entrant generation interacts with networks is done so without sufficient regulation. The CEC [Clean Energy Council] believes that in almost all of these cases networks behave in the exact ways that the Commission describes that an unregulated monopoly would behave. (sub. DR97, p. 4)

And that:

… the current negotiating frameworks are failing to produce efficient outcomes as a result of market power held by TNSPs. New generators are unable to connect efficiently and, ultimately the increased cost is distributed to consumers. (sub. DR97, p. 9)

Monopoly behaviour can manifest in delays, lack of information provision and passing on (greater than efficient) costs to new generators. Further, where new connections also require upgrades in other areas of the shared network to deal with issues such as higher loads being transferred, it is difficult for new generators to objectively assess whether or not they are paying for just the required upgrades, or whether additional costs are also being passed on (AEMO, sub. DR100, p. 9).

The Victorian Government has long held concerns in relation to this, stating that:

Under current connection arrangements there are insufficient regulatory controls on TNSPs to ensure that connection applicants receive ‘fair and reasonable’ treatment. The outcome of any given connection process is highly dependent on the willingness of the TNSP to proactively engage, and on the TNSPs providing the required information to the applicant to enable them to negotiate on the basis of full information. Unfortunately, this fair treatment is often not forthcoming. (DPI 2012b, attachment p. 13)

Outside Victoria, access arrangements under the Rules are delivered as negotiated transmission services. However, as put by the Clean Energy Council, an efficient outcome from this arrangement requires the connecting party to have countervailing market power (sub. 97, p. 7).

Concerns have also been raised over the Victorian arrangements. In regard to AEMO’s role in Victoria as a ‘procurer’, some participants have expressed concerns about the costs involved for businesses submitting tenders, for the incumbent transmission business, for the generator, and for AEMO when carrying out the tender process. Some participants (for example, the National Generators Forum, sub. DR93) have also claimed that the process in Victoria creates requirements to negotiate many contracts with different parties, creating significant additional transaction costs. Similar sentiments were expressed by AGL Energy (trans., p. 223) which saw the involvement of AEMO in Victoria as adding few benefits but adding delays, cost and complexity. While remaining concerned about the market power of TNSPs, AGL Energy maintained that when seeking new connections they would prefer to deal directly with the relevant TNSP.

### Proposed reforms

As part of the Transmission Frameworks Review, the AEMC is considering reforms to the connections process. In order to deal with the issues of monopoly behaviour identified above, the AEMC’s second interim report (AEMC 2012j, p. 84) recommended reforms designed to strengthen the negotiating framework. These include:

* requiring TNSPs to publish a standard connection contract, and ‘design standards and philosophies’ for analogous distribution connections
* requiring TNSPs to provide connection applicants with detailed cost, assumption and calculation information and evidence
* a power for the AER to develop and enforce guidelines on specific information that TNSPs must provide to applicants.

The AEMC also sought to provide connection applicants with a greater role in the tendering process for connections (a process which would be run by the TNSP), by requiring TNSPs to provide applicants with:

* all contractors’ responses to the tender
* a detailed business case for the choice of contractor, including demonstrating that the TNSP has considered the applicant’s preferences in selecting the winning contractor.

Separately to *connections*, the AEMC also sought to clarify the rules to allow a connecting party to tender for an *extension*, in whole or part (the AEMC’s delineation between connections and extensions is depicted in figure 16.3). They noted that TNSPs could participate in the tender, but that the applicant can request that the TNSP provide the extension as a negotiated (that is, regulated) transmission service. Finally, the AEMC considered that, due to competition concerns, controlling ownership of both generation and shared transmission assets should not be allowed.

The AEMC’s proposed reforms essentially followed the principle that ‘competition for services will lead to the most efficient outcome, where it can be effectively implemented’ (AEMC 2012j, p. 87). In implementing this principle, the AEMC has proposed contestability for extensions, but have stopped short of this in the case of connections, relying on increased transparency to curtail monopoly power.

The AEMC argued that connections should remain the responsibility of TNSPs because:

… they are responsible for security and reliability of the shared network, which could be impacted by the design and construction of the connection. … There is an inherent tension between the desire for a connecting party to minimise its costs of connecting to the transmission system and the advantage to a TNSP of having the most reliable and long-lasting transmission assets possible. (AEMC 2012j, pp. 86‑7)

Through the course of the Transmission Frameworks Review, AEMO put forward an alternative contestability framework (detailed below, and in AEMO 2013d). Essentially, AEMO agreed with the objectives of introducing competition for services where practical, and maintaining the security and stability of the network. However, AEMO differed from the AEMC’s model in two key respects:

* defining the boundary between those services, which could be subject to contestability and those that could not (depicted in figure 16.3). While the AEMC considered that contestability should only apply up to the ‘substation fence’, AEMO argued it could apply up to the interface with an existing transmission line
* the means for ensuring system security. Rather than simply retaining responsibility with the TNSP, AEMO argued that they could stipulate technical requirements at the connection to ensure system security. The construction of new assets, by the incumbent or any other successful tenderer, would be required to meet these specifications.

While the difference in boundary definition could seem minor, the Commission received confidential information that typically the sub-station component alone represents more than half of the capital cost required for a new connection, and could be as large as 80 per cent for some connections. This suggests that any gains from contestability will also be proportionally larger if they include sub-station works.

Figure 16.3 The boundary of a contestable connection

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| Figure 16.3 The boundary of a contestable connection. This figure shows what components of a new connection are contestable and non-contestable. |

*Data sources*: Based on AEMC (2012j); AEMO (2013d).

While the AEMC’s approach to connections covers several other aspects of the process (such as clarifying the National Electricity Rules, and transitioning extensions to shared network when other parties connect), the Commission agrees with the AEMC, in that reform should focus on introducing competition, where practical. The Commission’s suggested approach for connections reform is detailed below.

### Introducing contestability into new connections

A new ‘specifications’ based contestability model for the NEM, based on the broader contestability framework proposed by AEMO (sub. DR100, pp. 9‑10), could be adopted to introduce contestability into new connections (and possibly eventually to other separable projects should net benefits be proven). The approach overcomes the criticism to the current Victorian arrangements.

* Applications for connection to the network are made to AEMO who determines the required specification to upgrade and augment existing network infrastructure to accommodate the new connection. Unbiased information about the range of shared network upgrades that would be required to accommodate the connection is then provided by AEMO in an open and transparent manner. While this would require that TNSPs provide information to AEMO, it would be appropriate for a central body, with no financial interest at stake from any particular interpretation of the information, to provide this information to the market. Indeed, provision of this information meshes well with AEMO’s other functions. This was noted by the Clean Energy Council which suggested ‘… as AEMO has the ultimate responsibility for system security and constraint management, there should not be any barriers to [it] having access to all the necessary information’(Clean Energy Council 2013, p. 4).[[11]](#footnote-11) This process would go some way to alleviating the information asymmetry held by TNSPs over new generators and ensure that the safe operating state of the network will be maintained.[[12]](#footnote-12)
* Generators are then free to tender the separable component of the connection, subject to the published specifications to interested parties — including the incumbent TNSP. This aspect allows for third parties to compete for the building and ownership of the connection assets. Unlike the current practice in Victoria, AEMO would not be involved in any commercial negotiations. This will help to delineate lines of responsibility between the generator, the successful tenderer and AEMO and thereby improve accountability if an issue were to arise.
* The AER would oversee the process through the development and enforcement of a national negotiating framework (including guidelines for the provision of information by TNSPs), as envisaged by the AEMC (2012j, p. 86). The AER would also continue its present role of selecting a commercial arbitrator from the options put forward by the parties (if called on by the parties to do so).

AEMO (2013d) raises the possibility of cross-ownership of the transmission assets (including the substation) by other registered transmission operators (not the local incumbent). In the case of sub-stations, the degree of complexity involved, and the potential effects on the broader network from deficiencies with the operation of a sub‑station, suggest that cross-ownership is unlikely to have substantial net benefits. Therefore, the Commission proposes that the connection assets related to the sub‑station could be constructed under a ‘build and transfer’ arrangements where asset ownership was transferred to the incumbent TNSP, if it is in the owners commercial interest to do so.[[13]](#footnote-13) Ultimately, the details of such a transfer would be a commercial decision for the parties involved. If the incumbent TNSP won the tender, the generator would avoid the additional transaction costs of transferring ownership at the completion of works. This would represent one inbuilt advantage for the incumbent, and a consideration for the generator in selecting the winning bid. This allows the generator, a commercially motivated party (in a workably competitive market), to select the model it believes delivers the best value to it.

In relation to ‘extensions’ (works between the sub-station and the generator itself), the Commission agrees with the AEMC (2012j, pp. 100‑4) that provided a third party or the generator is either a licenced TNSP, or obtains an exemption from the AER, it could own the extension. Such exemptions should be subject to conditions including provision for third party access. Over time, some extensions can be accessed by other parties, or could be reclassified in such a way that they effectively become part of the shared network. The process for transitioning extensions into the shared network is being considered in some detail by the AEMC (2012j, pp. 101‑3).

The competitive disciplines placed on TNSPs should overcome a number of the concerns raised, such as delays, over pricing and possible risk transfers from TNSPs to generators that can arise in transactions with monopolists.

Further, using AEMO to set the specifications for the connection projects prevents the possibility for delay or opportunities to frustrate the process if it were left to the incumbent TNSP to complete. It will also ensure generators can be confident that they are not paying for upgrades to shared network infrastructure that are not related to their connection. Indeed some generators have already expressed support for AEMO’s model, and argued that it would ‘make significant enhancements to the efficiency of new connections’ (Clean Energy Council 2013, p. 5).

Implementation of this approach, however, could be hampered by other regulatory barriers that restrict competition. In their submission to the AEMC’s *Transmission Frameworks Review* (2011f and 2012j) Transmission Operations Australia raised concerns over barriers created by licensing arrangements:

There are competition barriers in jurisdictions such as NSW and Queensland. However, these competition barriers are not due to the inherent nature of the electricity transmission market but rather due to imposed legislative and regulatory barriers. For example, in NSW TransGrid is a legislated monopoly and in Queensland the process for obtaining a transmission license is not transparent. (TOA 2012, p. 3)[[14]](#footnote-14)

Accordingly, in order to implement this new approach, all jurisdictions in the NEM would have to ensure that their licensing regimes (and other regulatory imposts such as environmental and planning approval) are transparent and do not contain any unnecessary barriers to the competitive provision of the transmission augmentations needed for new connections.[[15]](#footnote-15)

Grid Australia has also raised concerns over the ability of AEMO to determine connection specifications that ensure system security without specifying the details of the actual configuration of the connection assets (Grid Australia, pers. comm., 27 February 2013). If the detailed configuration is specified, Grid Australia argued that all that will be tendered is the procurement and construction component of the connection, much as a TNSP would do under the current arrangements. This would limit the benefits from contestability, albeit the benefits arising from having the generator undertake the tender would remain. However, in an analogous augmentation to the network, AEMO has shown that it can indeed tender based on specifications that do not extend to being prescriptive over the configuration of assets required — in its network support and control ancillary services tender of 2012.

Recommendation 16.10

The Australian Energy Market Operator (AEMO) should oversee the technical details of connection of new generators to the National Electricity Market to allow for contestability. AEMO should:

* on receipt of an application for connection from a generator determine, in consultation with the relevant transmission business, the details of the augmentation and upgrades to shared network infrastructure that would be required to implement the connection, as well as the detailed specifications that ensure that the safe operating state of the network is maintained. This would complement information provided by the transmission business. The transmission business would have the opportunity to review and provide commentary on AEMO’s proposed specifications but AEMO would make the final decision on the required specifications
* provide the specifications to enable the generator to seek tenders to build the connection assets.

The Australian Energy Regulator should provide guidelines on the provision of information from transmission businesses to new connection applicants.

This framework should replace the existing arrangements in Victoria immediately and be implemented elsewhere in the National Electricity Market once Victorian arrangements are finalised and any regulatory barriers have been overcome.

1. For example, the AER recently approved more than $2 billion in capital expenditure for load driven augmentations and replacements in Powerlink’s latest revenue determination (2012 to 2017). [↑](#footnote-ref-1)
2. ‘The Group’ includes Loy Yang Management Company, AGL Hydro, International Power Australia, TRUenergy and Flinders Power. [↑](#footnote-ref-2)
3. In the final stages of preparing this report the AEMC released an issues paper for it review of National Frameworks for Transmission and Distribution Reliability (AEMC 2013c) which canvasses many of the issues discussed in chapter 14, 15 and this chapter. [↑](#footnote-ref-3)
4. SCER issued the AEMC with a terms of reference for a review to develop new approaches for the regulation of electricity distribution and transmission reliability across the NEM which incorporate the value customers place on reliability on 14 February 2013 (SCER 2013b). [↑](#footnote-ref-4)
5. This was set out in the second interim report of the Transmission Frameworks Review (AEMC 2012j) and the Transmission Reliability Standards Review (AEMC 2010a), the latter of which was largely endorsed by the MCE (2011). [↑](#footnote-ref-5)
6. Under the Rules, a contingent project is defined as a project assessed by the AER as reasonably required to be undertaken, but which is excluded from the ex-ante capital expenditure allowance in a revenue determination because of uncertainty about its requirement, timing or costs (AER 2007c). The Commission recognises that the current contingent project arrangements were designed for a different purpose than that envisaged by the Commission for large reliability-related expenditures. In particular, under the Commission’s proposed arrangements, there is no requirement for any uncertainty about the costs, timing or need for the project. Accordingly, a large project would still be treated as ‘contingent’ even if at the time of the regulatory determination, AEMO’s NTNDP suggested that it was *certain* that the project would be needed some time in the coming regulatory period. The required revenue for such a project would be appraised in a process separate from the general revenue determination process, and at a time close to the investment process commencing. [↑](#footnote-ref-6)
7. A real options approach in the context of transmission planning allows investment decisions for reliability, once a potential constraint has been identified, to be delayed past the start of the regulatory period until the time that they are needed. The benefits of this approach are twofold. Firstly, if predictions about the level of reliability that customers value turn out to be incorrect, the required investment path can be altered. For example, if an industrial estate closes down, the level of reliability that the remaining customers desire would fall. The second benefit arises from being able to take advantage of technology improvements or changing financial conditions or other network augmentations built in neighbouring regions. Delaying the decision about exactly what to build and how much it will cost until closer to the time of the project starting, allows the most recent developments to be taken into account. [↑](#footnote-ref-7)
8. Arcing is when electricity flashes over from one piece of equipment to another, or something else, such as a tree, creating a fault on the network. [↑](#footnote-ref-8)
9. A separable project is one that can readily be identified as distinct from the rest of the network. Further, while it will require connection to the broader network, to be categorised as ‘separable’, a project must not materially interfere with the incumbent transmission business’s ability to run existing infrastructure. To date, 15 separable projects have gone to tender in Victoria (of which the incumbent transmission business, SP AusNet, has been awarded 13). The outcomes of these tenders are currently commercial in confidence and are not communicated to the AER, and the capital expenditure is therefore not incorporated into SP AusNet’s RAB at the start of the next regulatory period. [↑](#footnote-ref-9)
10. OFA arrangements are targeted at providing firm access for generators to downstream markets. The arrangements, through proposed price controls, also include regulation that seeks to limit the potential for TNSPs to exploit any market power over incumbent generators when providing firm access — chapter 19. Broader issues of market power and transmission businesses are being examined by the AEMC’s Transmission Framework’s Review (AEMC 2011f and 2012j). [↑](#footnote-ref-10)
11. To the extent that the acquisition, compilation, analysis and publication of the additional information would require additional staff and resources for AEMO, these costs should be recovered from connection applicants (who benefit from the information), rather than ‘spread’ as network charges. [↑](#footnote-ref-11)
12. There may be elements deep within the shared network where the information asymmetry in favour of the TNSP is effectively insurmountable due to, for example, complex network interactions or specific local knowledge (of topology or local regulation). Improving transparency by both AEMO and the TNSP providing information to the applicant would go some way to ‘shedding light’ on this work but, as noted below, there are some areas where it is best that the TNSP conduct the work. [↑](#footnote-ref-12)
13. Once the asset ownership has been transferred to the TNSP, as a ‘negotiated transmission service’, it would not be counted as part of the RAB (National Electricity Rules, clause 6A.6.1(a)). [↑](#footnote-ref-13)
14. In a submission to the AEMC, TransGrid (2012) obtained legal advice suggesting that ‘any company’ can build own and operate extensions to the transmission network. However, in order to obtain compulsory acquisition powers (to acquire easements over land), a company must apply to the relevant New South Wales Minister for an order under the *Electricity Supply Act 1995* (NSW). To date, one company (Directlink) has been granted such an order (TransGrid 2012, attachment, p. 2). [↑](#footnote-ref-14)
15. In considering the presence of entry barriers for generator ‘extensions’, the AEMC (2012j) examined the state-based licensing requirements and land acquisition powers across the NEM. It concluded that South Australia, where ‘third parties can readily obtain transmission licenses and own and operate extensions’ (AEMC 2012j, p. 143), had the most competition for the provision of extensions. A full examination of barriers to entry would also need to consider if broader government approvals (such as environment and planning) afford any competitive advantages to incumbents. [↑](#footnote-ref-15)