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Alternative Transmission Planning Arrangements: Ensuring Nationally Coordinated Decision-making

A Report prepared for the AEMC

May 2012

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Executive Summary

NERA Economic Consulting (NERA) and Allens have been asked by the Australian Energy Market Commission (AEMC) to develop an alternative transmission planning framework for the National Electricity Market (NEM). The focus of this alternative framework is on ensuring national coordination of planning across the NEM. Specifically, a nationally coordinated approach ensures that the choice of options being considered for investment includes all relevant options, and is not limited by jurisdictional boundaries.

We have not been asked as part of this assignment to assess the current arrangements for transmission planning. We therefore do not undertake an assessment of the status quo arrangements, nor have we considered potential enhancements to the current arrangements. Instead, the focus is to develop an *alternative* option for transmission planning, which can be compared to the current arrangements. However, in doing so we have had regard to the current institutional arrangements in place with respect to planning in the NEM, and the current roles and responsibilities carried out by those institutions.

Process for developing an Alternative Transmission Planning Framework

The focus of the alternative transmission planning framework is to ensure nationally coordinated decision-making. In developing the alternative transmission planning framework we have followed a five step process:

- **Step 1:** clarify the focus of the alternative planning arrangements;
- **Step 2:** develop a list of roles and responsibilities associated with transmission planning. The alternative framework needs to clearly identify the institutions that are responsible for each of these roles and responsibilities;
- **Step 3:** identify appropriate principles to guide the development of the framework;
- **Step 4:** consider different institutional arrangements for planning, and the extent to which each of these are likely to satisfy the identified principles; and
- **Step 5:** build upon the optimal institutional arrangement identified in step 4, and develop the alternative framework in detail, including approaches to implementation.

Step 1: Clarify the focus of the Alternative Planning arrangements

We have identified two key areas that the alternative framework should be focused on achieving, specifically:

1. ensuring that the investment options identified to meet a given investment need take into account *all* potential options, and are not limited by geography or jurisdiction; and
2. ensuring that the investment decisions made reflect the optimal option out of all of those identified, ie, that the national coordination in the identification of options is also reflected in the actual investment decisions themselves.

Step 2: Roles and responsibilities

The various roles and responsibilities connected with transmission planning can be grouped into five high-level areas, specifically:

1. Planning: long-term and short term;
2. Project specific planning/investment decision;
3. Implementation of investment;
4. Ownership, O&M and liabilities; and
5. Revenue regulation, compliance and reliability standards.

Step 3: Principles to guide development

We have identified eight principles to guide the development of an alternative transmission planning framework, as set out below.

Principle 1: Promote transmission system investment decision-making on a coordinated basis to maximise net market benefit (defined as the benefit to all those who produce, consume and transport electricity in the NEM).

Principle 2: Allow for both local input and a strategic perspective.

Principle 3: Allow the use of incentives to promote efficient investment decisions.

Principle 4: Minimise conflicts of interest.

Principle 5: Maximise net benefits from reform.

Principle 6: Allow risk to be allocated to the party that is best able to manage the risk.

Principle 7: Be clear and transparent in approach.

Principle 8: Does not create barriers to connection.

We note in relation to Principle 1 that coordination across NEM regions is not required for *all* network investments. In principle, different types of investments can be distinguished on the basis of whether the geographic spread of alternative options covers more than one region or jurisdiction (and therefore may require coordination) or whether all options will inevitably fall within the same region. However there is no ‘bright-line’ between these two types of investment, which means that the potential for coordination is a relevant consideration in all cases.

We also have regard to the following COAG principles in developing the alternative framework:

Accountability for jurisdictional investment, operation and performance will remain with transmission network service providers.

Where possible, the new regime must at a minimum be no slower than the present time taken to gain regulatory approval for transmission investment.

The new regime must not reduce or adversely impact on the ability for urgent and unforeseen transmission investment to take place.

Steps 4 & 5: Alternative Transmission Planning Framework: nationally coordinated decision making

The institutional arrangement that seems to best meet the above principles is that of a nationally-focused planning body (the National Transmission Planner (NTP)) interacting with and advising individual Transmission Network Service Providers (TNSPs) as part of their planning functions across the NEM.

Our alternative transmission planning framework builds on this arrangement, and includes three additional components specifically targeted at ensuring national coordination:

- a requirement for increased consultation between TNSPs, focused on ensuring that all relevant options are considered in planning decisions, regardless of jurisdictional boundaries;
- an enhanced role for the NTP in:
  - reviewing and commenting on the TNSP's draft Annual Planning Report's (APRs) and draft Regulatory Investment Test for Transmission (RIT-T) documentation, with the focus on ensuring that options in other regions are being adequately considered;
  - supporting a consistent approach to planning by providing demand forecasts to all TNSPs and undertaking advisory roles for planning and reliability standards; and
- an enhanced role for TNSPs in the development of the National Transmission Network Development Plan (NTNDP), to ensure that coordination between national and local issues occurs at the outset of the planning process.

Requirement for TNSPs to consider options in other regions

The alternative framework includes changes to the National Electricity Rules (NER) imposing a new requirement for consultation between relevant TNSPs in preparing their APRs, and undertaking RIT-T and non-RIT-T assessments.

When APRs are developed by TNSPs, they would need to set out whether there are options located either wholly or partly in other regions that could potentially address the identified need. These options would be identified and developed through consultation with neighbouring TNSPs. TNSPs would also be required to state in their APRs if they do not consider that options in other regions would meet the identified need for the investment, where that is the case, and the reasons why. The NTP could be required under the NER to develop guidelines on assessing whether an investment need could be met by an investment in another region.

This approach would follow through to project specific plans, with TNSPs being required to consider options in other regions in both their RIT-T and non-RIT-T assessments. Where such options are identified as relevant, they would then be considered in the evaluation of the particular investment. Again, where options in other regions are not considered relevant, this would need to be documented, and reasons given for why not.

If an option in another region was identified as being the preferred option under the project specific planning, the TNSP in the other region would need to agree to be the proponent of that option (or another provider, in the event that the investment could be treated as contestable). If the option did not have a proponent, then it could not be chosen as a preferred option by the TNSP.

It would also be important that the economic regulatory regime does not provide a disincentive for TNSPs to agree to be proponents. We consider that there are two potential economic regulation routes that could occur where this ‘other region’ TNSP is a proponent – either assets could be proposed as contingent projects, or could be treated under the existing capital expenditure allowance. In either route there are no financial disincentives on the ‘other region’ TNSP to be a proponent.

Enhanced NTP role

The second key element of the alternative framework is an enhanced role for the NTP, to facilitate increased coordination across the NEM, including in relation to the new NER requirements for TNSP-TNSP consultation discussed above.

Specifically, under the alternative framework:

- the NTP would review each TNSP’s draft APRs, and highlight to TNSPs where it appears that there would be a benefit from coordination;
- the NTP would comment on the draft RIT-T Project Specification Consultation Report (PSCR) prepared by the TNSPs, with a focus on highlighting those areas where options in one region may help in addressing an investment need in a different region; and
- the NTP would provide demand forecasts to TNSPs as a starting point for the forecasts adopted by the TNSPs in their APRs, RIT-T and non-RIT-T assessments;
- the NTP would provide an advisory role to the AER in relation to economic regulation and monitoring compliance with the RIT-T, and also to the institutions involved in the setting of reliability standards.

The NTP’s role in reviewing draft APRs, would be to highlight where it appears that individual TNSPs are planning investments which have complementarities, or where it appears that an investment need could potentially be met by investment options in other regions. This role would act as a check on the TNSP-TNSP consultation requirement in the NER, and would provide a further avenue for TNSPs to become aware of what others are planning. The NTP would flag with the TNSP that it should be consulting on a particular investment with neighbouring TNSPs.

The NTP’s role in highlighting areas where coordination is likely to be beneficial would be further pursued through a new role in advising on the consideration of investment options in neighbouring regions as part of the RIT-T process. The NTP’s role in relation to providing input into both the APR and RIT-T processes conducted by the TNSPs would be specifically targeted at identifying areas where coordination with other TNSPs should be occurring.

In addition, under the alternative framework the NTP would provide a standardised set of demand forecasts to TNSPs across the NEM. This would provide a consistent starting point for the demand forecasts used in planning across the NEM. TNSPs should be permitted to deviate from the NTP's forecasts where local knowledge suggests this is appropriate, including where the TNSP has more detailed information as a result of forecast demand provided by the relevant DNSPs. However the TNSP must clearly state how and why they have deviated from the NTP's forecasts.

Enhanced TNSP input into NTNDP

The final element of the alternative framework is a role for enhanced TNSP input into the NTNDP. This would ensure that coordination between national and local issues occurs right at the outset of the planning process.

This enhanced TNSP input would occur through a working group, comprised of TNSP representatives from all jurisdictions, being involved in advising the NTP in the preparation of the NTNDP. This working group would comment on, and provide input to, the NTP in the development and preparation of the NTNDP, with the ultimate responsibility for the NTNDP remaining with the NTP. This role would complement the NTP's role in commenting on aspects of the TNSP's APRs and RIT-T applications.

Roles and responsibilities under the Alternative Framework

Table E.1 sets out the roles and responsibilities for each of these five institutions under the alternative transmission planning framework.

There are five key institutions involved in the alternative framework:

- the NTP;
- the 'home' TNSP', ie, the TNSP in the jurisdiction where the need has been identified;
- the 'other region' TNSP' ie, a TNSP in a region other than that of the 'home' TNSP;
- the Australian Energy Regulator (AER); and
- an 'other body' (ie, the AEMC or jurisdictional regulators).

The alternative planning framework proposed in this report can be mainly implemented through the NER and does not require significant changes to the NEL.

We note that the alternative framework provides for an enhanced role for the NTP. One of the benefits of this enhanced role is that it provides a degree of oversight and review in the planning process, by allowing for the views of two different parties to interact. In Victoria, the NTP and the jurisdictional planning body are currently the same entity, ie, the Australian Energy Market Operator (AEMO). Accordingly, the benefits associated with the separation of these roles are not able to be delivered in the Victorian jurisdiction.

We consider that there are a number of institutional reforms that could be undertaken in order to address these issues, each of which would require the support of the Victorian Government. These options are:

- ringfencing – the part of AEMO that undertakes some or all of the Victorian declared network functions to be ringfenced within AEMO;
- new Victorian planning entity – the relevant planning functions in Victoria to be carried out by a body other than AEMO; or
- transfer TNSP planning functions to SP Ausnet – the declared network functions to be given to SP AusNet, providing for separation of the NTP from jurisdictional transmission planning activities in Victoria

Table E.1
Roles and Responsibilities: Alternative Transmission Planning Framework

Roles		NTP	'Home' TNSP	'Other region' TNSP	AER	Other Body
Planning						
Long term strategic plan: NEM-wide (NTNDP)	Development of plan	**✓**	✓	✓		
Short-term detailed plan: regional and cross-regional (APR)	Development of plan	✓	**✓**	✓		
Project specific planning/ investment decision						
Identification of need			**✓**			
Demand forecasts		✓	**✓**			
Development of scenarios		✓	**✓**			
Identification of options		✓	**✓**	✓		
Evaluation (RIT-T, non-RIT-T)		✓	**✓**	✓		
Investment decision			**✓**			
Implementation of investment			**✓**	*		
Roles and responsibilities						
Transmission asset ownership, maintenance and operation			**✓**	*		
Responsibility/liability			**✓**			
Regulation and Standards						
Revenue regulation	Economic regulation				**✓**	
	How is asset owner compensated? (ie, economic regulation or contract payment)		economic regulation	primarily economic regulation		
Compliance with network planning requirements in NER					**✓**	
Setting of network reliability standards						**✓**
Advisory role to economic regulator, compliance monitor on RIT-T and standards		**✓**				

Note: ✓= Primary responsibility; ✓=Also involved
* If the 'other region' TNSP was prepared to become the proponent for the investment, then these roles and responsibilities would shift to the 'other region' TNSP.
# Note that if the 'other region' TNSP was the proponent, the 'home' TNSP would still need to provide input into the detailed design of the investment in order to ensure that it meets the relevant jurisdictional standards.

1. Introduction

NERA Economic Consulting (NERA) and Allens have been asked by the Australian Energy Market Commission (AEMC) to develop an alternative transmission planning framework for the National Electricity Market (NEM). The focus of this alternative framework is on ensuring national coordination of planning across the NEM. Specifically, a nationally coordinated approach ensures that the choice of options being considered for investment includes all relevant options, and is not limited by jurisdictional boundaries.

We have not been asked as part of this assignment to assess the current arrangements for transmission planning. Instead, the focus is to develop an *alternative* option for network planning. We therefore do not undertake an assessment of the status quo arrangements,[1] nor have we considered potential enhancements to the current arrangements.[2] However, we have had regard to the current institutional arrangements in place with respect to planning in the NEM, and the current roles and responsibilities carried out by those institutions.

We note that NERA was also engaged to undertake an international review of transmission planning arrangements in four North American jurisdictions (specifically, New York, PJM, California and Alberta).[3] The findings of this review have informed our development of the alternative planning arrangements considered here.

The remainder of this report is structured as follows:

- Section 2 sets out our approach to developing an alternative transmission planning framework;
- Section 3 sets out the principles we have adopted to guide the development of the alternative framework;
- Section 4 discusses alternative institutional approaches;
- Section 5 discusses the key features of our alternative transmission planning framework;
- Section 6 sets out in more detail the specific roles and responsibilities under the alternative framework;
- Section 7 assesses the alternative framework against the principles we have adopted; and
- Section 8 discusses the implementation of the alternative framework.

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1 We note that the current planning arrangements for transmission in the NEM are relatively new and still developing in practice. For example, the National Transmission Planner (NTP) was established on 1 July 2009, and the Regulatory Investment Test for Transmission (RIT-T) has only applied since 1 August 2010.

2 We note that the AEMC in its First Interim Report for its Transmission Frameworks Review identified a number of potential enhancements that could be made to the current arrangements. AEMC, First Interim Report: Transmission Frameworks Review, 17 November 2011, p.131.

3 NERA Economic Consulting, Planning Arrangements for Electricity Transmission Networks: An International Review, A Report for the AEMC, April 2012.

2. Development of an Alternative Transmission Planning Framework

In developing an alternative transmission planning framework, we have followed a five step process:

- **Step 1:** clarify the focus of the alternative planning arrangements (section 2.1);
- **Step 2:** develop a list of roles and responsibilities associated with transmission planning (section 2.2). The alternative framework needs to clearly identify the institutions that are responsible for each of these roles and responsibilities;
- **Step 3:** identify appropriate principles to guide the development of the framework (section 3);
- **Step 4:** consider different institutional arrangements for planning, and the extent to which each of these are likely to satisfy the identified principles (section 4); and
- **Step 5:** build upon the optimal institutional arrangement identified in step 4, and develop the alternative framework in detail, including approaches to implementation (sections 5 to 8).

We follow each of these steps in turn throughout this report. The remainder of this section discusses steps 1 and 2.

2.1. Focus of alternative planning arrangements

The focus of the alternative transmission planning framework is to ensure national coordination of decision-making. As a first step, we have therefore clarified what exactly we understand to constitute ‘nationally coordinated decision-making’.

In terms of ensuring nationally coordinated decision-making, we have identified two key areas which the alternative framework should be focused on, specifically:

1. ensuring that the investment options identified to meet a given investment need take into account *all* potential options, and are not limited by geography or jurisdiction; and
2. ensuring that the investment decisions made reflect the optimal option out of all of those identified, ie, that the national coordination in the identification of options is also reflected in the actual investment decisions themselves.

An approach which reflects national coordination of planning in the NEM would ensure that the choice of options considered for investment includes options in *all* relevant jurisdictions.[4] That is, the investment options considered should not be limited by geography or regional boundaries. For example, in some cases it is possible that a reliability standard in NSW could

[4] The DPI submission to the AEMC in response to the First Interim Report notes that “as TNSPs operate on a regional basis there is a risk that efficient inter-regional investment solutions will not be considered in their planning decisions.” See: Department of Primary Industries, Submission to the AEMC Transmission Frameworks Review – First Interim Report, 27 January 2012, p.11.

potentially be met by an option undertaken in either Queensland or in NSW. A nationally coordinated planning approach would ensure that both of these options are considered in determining the optimal investment.

Related to this, is the need to ensure that the investment decision itself reflects the most appropriate option, out of those identified. That is, not only are options in other regions identified and considered as part of the initial planning process, but they are also implemented where they are found to be optimal. Continuing the previous example, if an investment in Queensland can meet the NSW reliability standard and has a higher net market benefit than an investment in NSW to meet the same need, then the Queensland option should be chosen as the option for investment. This is important, since if the consideration of options across jurisdictions as part of the planning process is not also reflected in the outcome of investment decisions, then ensuring increased coordination at the planning stage will not serve any real purpose.

2.2. Roles and responsibilities

Given our clarification of the focus for the alternative framework (discussed above), we next consider the various roles and responsibilities associated with the network planning framework (step 2).

In identifying the various roles and responsibilities in connection with transmission planning, we consider that these can be grouped into five high-level areas, specifically:

1. Planning: long-term and short term;
2. Project specific planning/investment decision;
3. Implementation of investment;
4. Ownership, O&M and liabilities; and
5. Revenue regulation, compliance and reliability standards.

We discuss each of these areas in more detail below. The alternative framework needs to clearly set out those institutions that are responsible for each of these roles and responsibilities.

2.2.1. Planning

The first high level area is planning – Table 2.1 sets out the detailed roles and responsibilities associated with planning.

The planning role relates to consideration of the investment needs of the network in general terms, rather than specific investment decisions. Specific investments are likely to form part of the development of an overall network plan, particularly where the general plan has a shorter term focus. However we have distinguished between ‘planning’ undertaken at a broad level, and ‘project specific planning’, which relates to the detailed consideration of a particular investment (and is discussed in section 2.2.2 below). We note that this distinction is reflected currently in the roles and responsibilities in relation to planning in the NEM.

In terms of the general planning function, we have distinguished between long-term, more strategic planning, which is focused on the need for major new investments and has a longer-term focus (eg, more than ten years), and short-term planning, which is focused on the more near-term and driven by specific investment needs. We note that the distinction between long-term and short-term planning is again one which is reflected in the current planning arrangements in the NEM. It is also a feature of the planning frameworks adopted in other markets. For example, in PJM the Regional Transmission Expansion Plan developed by the Regional Transmission Organisation (PJM Interconnection LLC) assesses both the near-term (5-year) needs of the regional power grid as well as those over the long-term (15 years).

Currently the long-term strategic planning function for the NEM is carried out by the National Transmission Planner (NTP),[5] who produces the National Transmission Network Development Plan (NTNDP). The NTNDP is a long-term strategic plan which is designed to provide an overarching, strategic view for the network over the next 20 years. It provides a holistic view of the entire system, and considers the major national transmission flow paths (ie, those areas of the transmission network connecting major generation or demand centres).

Developing this long-term plan involves a number of activities. These include identifying the areas of the network that need investment (ie, identification of investment need) and the development of the different scenarios to be used for planning purposes. These scenarios can cover different economic and government policy outcomes, demand forecasts and also generation scenarios.

The high-level strategic plan guides and informs the more detailed planning of the network. Currently the detailed planning is led by the development of short-term (ie, two-three years) plans for particular regions in the network, reflected in the Annual Planning Reports (APRs) that are developed by the jurisdictional Transmission Network Service Providers (TNSPs). We note that in other markets where there is a single network planner, separate sub-plans for specific regions are still typically developed.[6]

Again, various activities are involved in this short-term planning. Although the starting point is to draw upon the high-level strategic plan, more specified drivers for investments need to be developed (ie, identification of investment need). Like the high-level plan, the short-term plans also consider different potential outcomes through development of different scenarios, and accompanying demand forecasts for each of these scenarios. These scenarios and demand forecasts will typically be at a higher degree of specificity than those in the high-level plan. This is because they are likely to need to reflect more detailed aspects of particular investment conditions. For example, in their APRs TNSPs currently either use ‘top down’ demand forecasts such as those developed by the NTP, or ‘bottom up’ forecasts that are required to be provided by Registered Participants (including DNSPs) under clause 5.6.1 of the NER. However, in general the scenarios used in the short term plans should be informed by the higher-level strategic scenarios and forecasts.

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[5] NER 5.6A.2.

[6] For example, in in California the CAISO performs a five-year Local Capacity Requirement study to provide visibility to stakeholders relating to local capacity requirements. In New York, the Comprehensive System Planning Process (CSPP) is initiated by individual Transmission System Operators, who start by developing comprehensive plans for their individual service territories, which then form inputs into the system plan developed by the NYISO.

Table 2.1
Roles and Responsibilities - Planning

Roles	
Planning	
Long term strategic plan: NEM-wide (NTNDP)	Development of plan
	Identification of need
	Demand forecasts
	Development of scenarios (incl. generation)
Short-term detailed plan: regional and cross-regional (APR)	Development of plan
	Identification of need
	Demand forecasts
	Development of scenarios

2.2.2. Project specific planning / investment decision

The second high level area is the project specific planning, and the investment decision – Table 2.2 sets out the activities associated with this specific area.

Project specific planning relates to a particular investment need, and culminates in a particular investment decision. In some other markets this project specific planning is undertaken as part of the development of the short term plans discussed above. For example, the Comprehensive System Planning Process (CSPP) conducted by the New York Independent System Operator (NY-ISO) results in the identification of specific investment projects.

In contrast, in the NEM there is a separate and distinct process for individual investment decisions, specifically the application of either the Regulatory Investment Test for Transmission (RIT-T) or an equivalent non-RIT-T assessment. In Alberta there is an equivalent 'project specific planning process', following on from the general planning process, which culminates in a Needs Identification Document (NID) for each investment.

In the project specific planning process in the NEM, a detailed cost benefit assessment is undertaken (ie, the RIT-T, or an equivalent process for non-RIT-T investments) to identify the investment option which has the highest net benefits. As part of this process, the first step is to again set out why the investment is needed ie, to identify the need. This can either be to meet a reliability standard or to deliver overall positive net market benefits. Different scenarios then need to be developed, under which the costs and benefits will be assessed. Demand forecasts are typically developed for each scenario. These may be informed by the scenarios and demand forecasts used in the planning function and described above.

Following the evaluation, the investment decision is made, ie there needs to be a decision as to which investment will be undertaken. This decision should reflect the investment option identified as optimal through the evaluation process.

Table 2.2
Roles and Responsibilities – Project Specific Planning / Investment Decision

Roles
Project specific planning/ investment decision
Identification of need
Demand forecasts
Development of scenarios
Identification of options
Evaluation (RIT-T, non-RIT-T)
Investment decision

2.2.3. Implementation of investment

The third high level area, following the investment decision, is the actual implementation of the investment – Table 2.3 sets out the related roles and responsibilities for this area.

The implementation of a particular investment involves a number of detailed activities in order to construct and then commission the asset. These activities include:

- obtaining planning permissions – relevant approvals need to be gained by the institution who is responsible for constructing the asset eg, from the relevant jurisdictional planning department or authority;
- obtaining easements – easements/wayleaves also need to be procured (either through purchase or leases) in order to enable the siting of the asset;
- outage planning – the construction of the asset is likely to require outages to other associated equipment, in order to connect it to the network. These outages need to be planned in order to ensure that the safety, security and reliability of the remainder of the system is not comprised;
- detailed design – the asset needs to be specified to a sufficient level of detail in order for it to be constructed;
- procurement of materials – the materials necessary for construction of the asset (eg, capital equipment, parts, etc) need to be procured, with this normally occurring through competitive tender managed by the asset owner;
- procurement of resources – the resources necessary for the construction of the asset (eg, labour etc) need to be procured, with this normally occurring through competitive tender managed by the asset owner;
- management of site works – while the asset is being constructed the site works around the construction of the asset needs to be managed, with this including controlling traffic flows etc; and
- commissioning – the final stage in the implementation of the investment is the commissioning of the asset, when it is placed into use.

Table 2.3
Roles and Responsibilities – Implementation of Investment

Roles
Implementation of investment
Obtaining planning permission
Obtaining easements
Outage planning
Detailed design
Procurement of materials
Procurement of resources
Management of site works
Commissioning

2.2.4. Ownership, O&M and Liabilities

The fourth high level group of roles and responsibilities relates to ownership, operation and maintenance (O&M) and liabilities – as set out in Table 2.4.

Once the investment has been constructed and commissioned, it is necessary to consider who owns, operates and maintains the asset over its life.

Transmission asset ownership is associated with the institution who 'owns' the asset. Importantly, this may be different to the institution that has *responsibility* for the asset. That is, the institution who bears the risks and liabilities associated with the asset (ie, the responsibility) may not necessarily own the asset. However, if these institutions are not the same, this separation of roles and responsibilities is typically managed through a contract between the asset owner, and the institution responsible for it.

These institutions may also be different to those that maintain and/or operate the asset. Maintenance of the asset ensures that it is kept in accordance with a specified set of standards. Operation of the asset ensures that it is operated in accordance with a given set of criteria.

Table 2.4
Roles and Responsibilities – Ownership, O&M and Liabilities

Roles
Ownership, O&M and Liabilities
Transmission asset ownership
Maintenance
Operation
Responsibility/liability

2.2.5. Revenue regulation, compliance and reliability standards

The last high level area relates to revenue regulation, compliance and reliability standards – Table 2.5 sets out the roles and responsibilities associated with this area.

Transmission services are natural monopolies, and so are typically subject to economic regulation of the revenues that they can earn. There needs to be arrangements determining how the asset owner is compensated, by whom and on what basis.

The type of compensation that the asset owner receives may depend on the institutional framework in place. If the business that owns the asset is also responsible for the provision of transmission services using that asset, then it will likely earn regulated revenue through receiving regulated Transmission Use of System Charges (TUOS charges) for the use of the asset. This is how economic regulation is currently applied in the NEM (as administered by the Australian Energy Regulator (AER)), for all jurisdictions apart from Victoria. If the asset owner is not also responsible for the provision of transmission services, then it may instead receive a contract payment from the individual who is (eg, a 'planner-procurer, such as AEMO in Victoria). This second body should then being subject to some form of economic regulation. We note that AEMO is not currently subject to economic regulation. However, 'planner-procurers' in other markets are subject to regulation eg, the California Independent System Operator (CAISO) in California, whose transmission planning processes and investment decisions are approved by the US Federal Energy Regulatory Commission (FERC).

There is also a compliance monitoring role, ensuring that network planning is undertaken in accordance with planning requirements as set out in the National Electricity Rules (NER) (including the application of the RIT-T) and any relevant jurisdictional regulations or instruments.

One of the key drivers of network investment is the need to meet network reliability standards. The setting of reliability standards is therefore a key activity as part of the overall planning framework.

There may also be an advisory role to those institutions responsible for regulation, compliance and standards. Such advisory roles may enable more detailed system planning knowledge to be provided to the institutions with primary responsibility in these areas, to assist them to fulfil their obligations more effectively. For example, the NTP currently provides an advisory role to the AER, who is responsible for economic regulation and compliance monitoring of RIT-T assessments in the NEM.[7] Similarly, in South Australia, the jurisdictional regulator (ESCOSA) sought input from the NTP as part of its review of reliability standards.

[7] Specifically, the AER in considering whether the operating and capital expenditure criteria are met in assessing regulated business proposals must have regard to (amongst other things) the most recent NTNDP, and any submissions made by AEMO on the forecast operating and capital expenditure. NER 6A.6.6(e) and 6A.6.7(e).

Table 2.5
Roles and Responsibilities – Regulation and Standards

Roles	
Regulation and Standards	
Revenue regulation	Economic regulation
	Advisory role to economic regulator
	How is asset owner compensated? (ie, economic regulation or contract payment)
Compliance with network planning requirements in NER	Compliance monitoring
	Advisory role to compliance monitor on RIT-T
Network reliability standards	Setting of standards
	Advisory role in relation to standards

2.3. Summary

We have identified the key focus of an alternative transmission planning framework to be ensuring nationally coordinated planning and decision-making, by ensuring that options for investment are identified without being limited by jurisdictional borders.

The alternative planning framework needs to allocate roles and responsibilities over five high level areas associated with network planning and investment.

Given this focus, and having identified the relevant roles and responsibilities, we next consider the principles that should guide the development of an alternative framework (step 3). We discuss these principles in the following section.

3. Principles for Identifying an Alternative Transmission Planning Framework

We have identified eight principles to guide the development of an alternative transmission planning framework. We discuss each of these in turn below.

3.1. Principle 1: Promote investment decision-making on a coordinated basis to maximise net benefit

Principle 1: Promote transmission system investment decision-making on a coordinated basis to maximise net market benefit (defined as the benefit to all those who produce, consume and transport electricity in the NEM).

The first principle is to ensure that the framework results in investment decision-making occurring on a nationally coordinated basis, in order to maximise the net benefit to the NEM. To the extent that investment decisions are made by multiple parties, outcomes should be no different to decisions made by a single body (thinking the same way). In other words, under the proposed approach, investment decisions made by multiple parties under a given set of evaluation criteria and principles, should be the same to those made by a single party under the same set of evaluation criteria and principles.

This principle is focused squarely on ensuring that national coordination of planning and investment decision-making occurs. However it is helpful to consider just what would be taken as reflecting a 'coordinated outcome'. We therefore discuss in more detail what national coordination entails below (section 3.1.1).

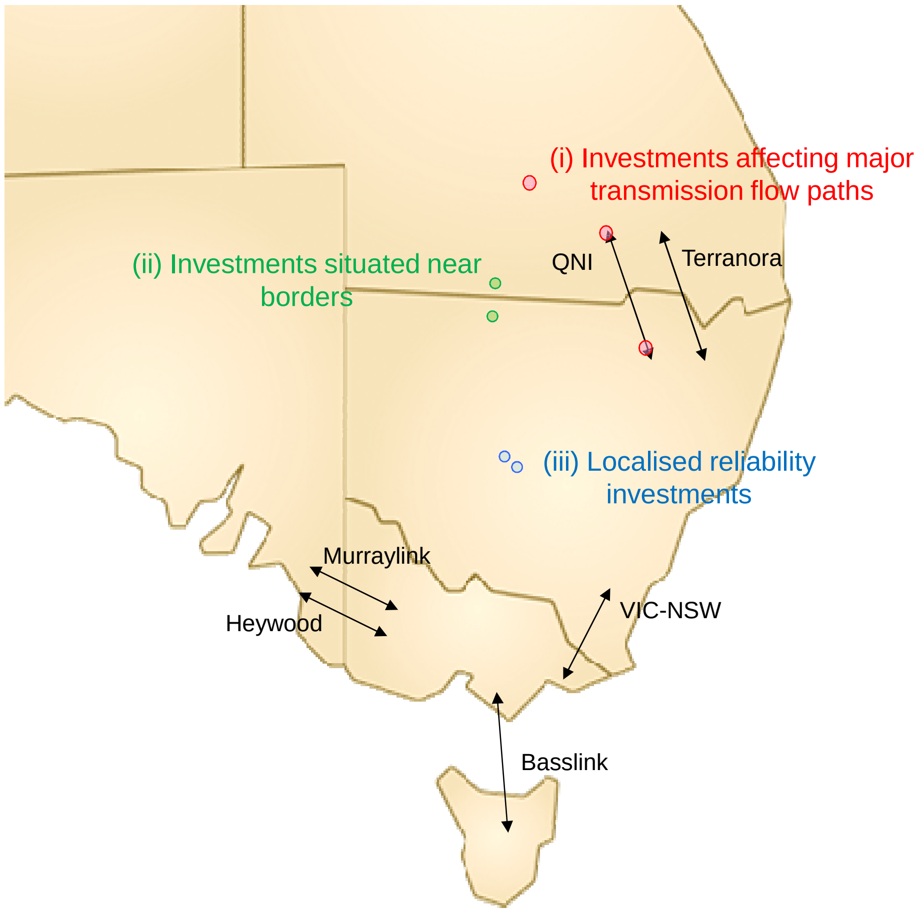
We note that the maximisation of net market benefit is consistent with the principles for investment decision-making set out in the NER in relation to the RIT-T, and is also relevant to investments not evaluated under the RIT-T. By taking into account the benefits associated with an investment decision, as well as the direct costs of the investment, the planning and decision-making process is better-aligned with identifying investments which will better meet the National Electricity Objective.

3.1.1. National coordination of investment decision-making

As discussed in section 2.1, we consider that 'national coordination' would be achieved where investment options in different NEM regions which may all address the 'identified need' for the investment are identified and considered as part of the planning process. That is, the options considered as part of the planning process are not limited to those within a particular geographic location.

Importantly, coordination of this type is not required across *all* investments. In principle, different types of investments can be distinguished on the basis of whether the geographic spread of alternative options covers more than one region or jurisdiction.

Figure 3.1
National Coordination of Investment Decision-making



In broad terms, we have identified three general types of investments, which are depicted in Figure 3.1:

- First are those investments that affect major transmission flow paths (including, but not limited to, interconnectors) – identified as the 'red' investments in Figure 3.1. These flow paths are used to transport significant amounts of electricity between generation centres, and major load centres.[8] Coordination is important for these investments, since the solution to an identified need could easily be one in another jurisdiction, or an investment which involves assets in multiple jurisdictions.
- Second are those investments near jurisdictional borders, where a credible option in another region may again address the identified need – ie, the 'green' investments shown in Figure 3.1. These can be either reliability-driven investments, or net market benefit

[8] AEMO, National Transmission Network Development Plan, 2011. We note that these investments are currently considered by the Australian Energy Market Operator (AEMO) in its National Transmission Network Development Plan (NTNDP).

investments. These also require coordination across jurisdictions, since the need for investment in one jurisdiction (eg, to meet that jurisdictions reliability standard) may potentially be addressed by an investment option in another region. For example, an investment in Queensland might be one option for meeting reliability standards in NSW. The need for coordination for these investments arises from the particular geographic location of the investments, more so than the type of investment being undertaken.

- Third are what can be considered purely ‘local’ investments – depicted by the ‘blue’ investments in Figure 3.1. These investments are ones for which all of the credible options are inevitably in the same region, eg, the need to maintain substation capability supplying Hobart. Coordination across regions in considering options for these investments is not important, since it is highly unlikely that the investment need can be met by an investment in another region. Indeed, if there were to be a single entity responsible for planning across the NEM, it is likely that these types of investments would only be considered by the ‘local planning division’ applying to that area, rather than also being considered by planners who also have a detailed knowledge of the network in other regions.

As a consequence, the key focus on nationally coordinated planning arrangements should be in relation to ensuring coordination for those investments affecting major transmission flow paths, and investments which are situated close to geographical borders.

However, importantly there is no “bright-line” between investments where options in other regions may be relevant, and ones where they are not likely to be relevant. More ‘extreme’ circumstances are likely to be easier to recognise. For example, where an investment is located close to a jurisdictional border, the likelihood of a similar investment the other side of the border also being a potential option is likely to be higher. Alternatively, a small upgrade to a transmission line in Cairns would likely not be met by an investment in another jurisdiction and so coordination is unlikely to be required. However, since these circumstances are likely to be few in number, the need for national coordination should be considered in all cases, and cannot be ruled out *a priori.*

We note that guidelines could potentially be developed on when options in other regions may be more relevant. We consider this further in section 6.1 below.

Lastly, we note that the type of national coordination to identify investment options which forms the focus on the alternative framework set out in this report differs from the ‘inter-regional impact’ / ‘inter-network impact’ which is currently required to be considered as part of the RIT-T. The RIT-T requires that the relevant TNSP should consider whether the credible option is reasonably likely to have a material inter-regional impact.[9] ‘Material inter-regional impact’ is not a defined in term within the NER, but it is has been generally assumed to be synonymous with ‘material inter-network impact’, which is a defined term.[10] This

9 NER 5.6.6(c)(6)(ii).

10 A material impact on another TNSPs network, which impact may include (without limitation): (a) the imposition of power transfer constraints within another TNSPs network; or (b) an adverse impact on the quality of supply in another TNSPs network.

NER, Glossary.

definition relates to technological constraints relating to the power system, which is different to considering options in other regions.

3.1.2. Net market benefit

We note that the maximisation of net market benefit is consistent with the principles set out in the NER in relation to the RIT-T, the purpose of which is to identify the option that 'maximises the present value of net economic benefit to all those who produce, consume and transport electricity in the market'. The maximisation of net benefit is also relevant for investments that are not covered by the RIT-T. The NER specify that these investments (with the exception of funded augmentations) must be planned and developed 'at least cost over the life of the investment'. In practice, TNSPs typically consider benefits (such as impact on losses) as part of these non-RIT-T assessments and so choose options based on the maximisation of net benefit.

In its development of the National Transmission Planning Arrangements, the AEMC considered that the definition of market benefits sufficiently allows for all national benefits to be assessed, ie, not just those focussed within a region of a TNSP.[11] This is consistent with ensuring a nationally coordinated approach.

We note that the scope of benefits to be considered in assessing electricity network investments, and in particular transmission investments, has been the subject of significant debate and development. The Australian Competition and Consumer Commission (ACCC) considered that the Regulatory Test (precursor to the RIT-T) should focus on those costs and benefits that are directly related to the proposed project ie, a partial equilibrium analysis. It maintained this position in its later review of the Regulatory Test. In the AEMC's subsequent review of the Regulatory Test principles, the AEMC expressed the view that "it would be inappropriate to discard the cost-benefit analysis framework that has already been well developed". We note that the assessment approach adopted in other markets also considers benefits in the context of those benefits accruing to the electricity market (rather than more broadly).[12]

3.2. Principle 2: Allow for both a local and strategic perspective

Principle 2: Allow for both local input and a strategic perspective.

Principle 2 is that the framework should allow for both local input and a strategic perspective as part of the planning process.

There is a need to ensure that there is sufficient 'local knowledge' as part of any planning framework. Network topography and local conditions vary substantially across the NEM. It is therefore important to allow for specialisation in planning across different areas. This specialisation may need to be even narrower than a whole NEM region.

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[11] AEMC, National Transmission Planning Arrangements, Final Report to MCE, 30 June 2008, p.46.

[12] For example, PJM, California and New York. See NERA Economic Consulting, Planning Arrangements for Electricity Transmission Networks: An International Review, A Report for the AEMC, April 2012.

Where planning is undertaken by a single body, it would still be likely have separate divisions or specialist planners for different geographies. For example, in Alberta the Alberta Electric System Operator (AESO) divides the Alberta Interconnected Electric System (AIES) into five regions that are differentiated based on distinctive load and generation characteristics, in order to assess transmission needs on a localised level.

The alternative planning framework should therefore aim to ensure that there remains sufficient 'local knowledge' in relation to specific areas of the network.

There is also a need to ensure that there is a 'long-term vision' for the network, which is not lost as a result of focus on more short-term investment drivers. We note that the earlier reforms which led to the establishment of the NTP had as a focus the need to ensure that the arrangements incorporated a long-term strategic outlook. Indeed, the Energy Reform Implementation Group (ERIG) concluded that a project by project assessment cannot be expected to deliver efficient, long term development of the national network and recommended that decision-making is not applied to an individual project in isolation, but rather from the perspective of the network as a whole.[13]

As discussed earlier, the planning frameworks in the North American markets we surveyed also incorporate both a short-term and long-term planning perspective, as well as ensuring that there is sufficient input to address localised planning issues.

3.3. Principle 3: Allow the use of incentives

Principle 3: Allow the use of incentives to promote efficient investment decisions.

Principle 3 is that the proposed framework should allow for the use of incentives in order to promote efficient investment decisions. That is, it should aim to align the private incentives of network planners and the other institutions involved in the planning process, with outcomes that are desirable from a market-wide perspective.

We note that incentives can be either positive or negative (eg, the application of penalties). Moreover, they can also be financial or non-financial (such as reputational incentives).

Financial incentives are generally considered to be the most effective and transparent form of incentive.[14] Financial incentives operate by exposing individuals to a share of the benefit or a share of the cost as a result of the outcomes of their actions. The NEM has adopted an incentive-based form of economic regulation, under which businesses are given the opportunity to make efficiency gains (and are exposed to the risk of cost over-runs), which are ultimately passed through to consumers. We note that some submissions received by the AEMC in response to the First Interim Report have raised concerns in relation to the effectiveness of financial incentives within the current regulatory framework in the NEM,

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[13] AEMC, National Transmission Planning Arrangements: Issues Paper, 9 November 2007, p.49.

[14] The Grid Australia submission in response to the AEMC's First Interim Report supported the use of well-designed financial incentives to promote the National Electricity Objective (NEO). Major Energy Users (MEU) also noted in its submission that financial incentives to do the "right thing" are better than incentives created through intrusive regulation.

such as the current incentive on TNSPs to defer capex to the end of the regulatory period.[15] We note that these concerns relate to the *current form* of financial incentives applying to the TNSPs under the NER, rather than relating to concerns with a fundamental principle of having financial incentives.

Non-financial reputational penalties can be important, particularly in providing a form of moral suasion. Finally we note that all bodies have incentives, whether financial or not. A not-for-profit body is not subject to financial incentives. However it will still be subject to other incentives, such as concerns with its reputation. Further, bodies with multiple roles, will have incentives stemming from these other roles. For example, the NTP is currently also the market operator. It may have an incentive to recommend increased investment in the network, in order to make its role in operating the market easier. In the case of a not-for-profit body, the alternative framework needs to consider the creation of incentives through the use of governance and effective oversight. In other markets where there are not-for-profit planner-procurers, they face oversight by regulators both in terms of their network planning processes, and their ultimate investment decisions.[16]

3.4. Principle 4: Minimise conflicts of interest

Principle 4: Minimise conflicts of interest.

The fourth principle is to minimise conflicts of interest amongst the institutions involved in transmission planning, to the extent possible.

There are a number of potential conflicts that are commonly mentioned in relation to transmission planning and which have been raised in submissions to the AEMC's First Interim Report. We discuss each of these in turn below.

3.4.1. NTP and Victorian jurisdictional planner

The NTP is designed to provide an independent high-level strategic plan for the NEM, with jurisdictional planners producing more detailed, short-term plans. Neither of these plans is bound by the other, but instead must have regard to each other.[17]

As a consequence, these arrangements in effect provides a degree of independent 'oversight' on each institution involved in the planning framework, and provides an additional view on

[15] The DPI submission notes that "the framework provides incentives on TNSPs to delay capital expenditure to the end of the regulatory period, rather than at a time in which investment might be required or justified by the wholesale market and generation developments. Further, the framework provides few incentives on TNSPs to make optimal trade-offs between network and non-network investment options, as investment-based augmentations are automatically rolled into the asset base."

See: Department of Primary Industries, Submission to the AEMC Transmission Frameworks Review – First Interim Report, 27 January 2012, p.11.

[16] For example, California and PJM. See NERA Economic Consulting, Planning Arrangements for Electricity Transmission Networks: An International Review, A Report for the AEMC, April 2012.

[17] NER 5.6A.2(b)(3)(i).

each of the plans being developed.[18] Under the current arrangements, different institutions are involved in long-term and short-term planning. This ensures that there is an appropriate tension, and check on the planning role within the market.

The AEMC noted as part of its earlier review of the National Transmission Planner Arrangements that:

> The NTP, as a highly informed participant, has the potential to add considerable value to the RIT-T process by providing independent views on whether an investment option or programme put forward by a TNSP is consistent with the efficient long term development of the network. This should strengthen incentives for TNSPs to consider the broader market benefits of the alternatives they put forward under the RIT-T assessments.[19]

We note that in other markets a single body is responsible for both long-term strategic planning and short-term localised planning. However the establishment of a separate body to undertake the high-level strategic plan was a conscious decision by COAG and the Ministerial Council on Energy (MCE) (now the Standing Committee on Energy and Resources (SCER)) following the ERIG review. This was reflected in the Terms of Reference given by the MCE to the AEMC for its report on the National Transmission Planner Arrangements.

The current exception to this arrangement is Victoria, where AEMO has both the NTP and jurisdictional planner role. We understand that there is no ring-fencing in place within AEMO between these functions.[20]

Importantly, even if AEMO is operating as an independent body, it cannot provide independent advice to itself.[21] Although it can be debated as to whether this is a ‘conflict of interest’, it is clear that under this arrangement there is only a single body involved in developing both the long-term strategic plan, and the short-term plan.

We consider that the current separation of roles in the other NEM regions provides benefits in the planning process by providing the oversight and tension noted above. We suggest that this would also be desirable as part of the alternative planning framework, and would ideally be implemented in all jurisdictions.

3.4.2. NTP and market operator

The second potential conflict of interest that has been raised is AEMO’s current role as both NTP and market operator.

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18 InterGen noted in its submission to the AEMC’s First Interim Report that the independent check of the TNSPs investment plans by the NTNDP is an important component of the current planning regime.

19 AEMC, National Transmission Planning Arrangements: Final Report to MCE, 30 June 2008, pp.14-15.

20 AEMC, First Interim Report: Transmission Frameworks Review, 17 November 2011, p.141.

21 AEMO, Submission to Transmission Framework Review First Interim Report, 20 February 2012, p.46.

Having both of these roles located in the same institution represents a potential conflict. It is possible that the NTP may have an incentive to recommend increased investment in the network, in order to make its role in operating the market easier.

We note that in practice concerns about this conflict of interest could be addressed via the specific planning arrangements adopted, and in particular the criteria applied in identifying the optimal investment option. In the NEM the evaluation criteria that must be applied to the investment are set out in the NER (ie, the specific circumstances that must be met under the RIT-T).[22] Investments proposed purely to make the operation of the market easier, and which do not provide other market benefits, would not pass the RIT-T. Similarly, in other markets where the same body has the market operator and planner role (eg, California, PJM), there are clear, criteria, approved by the regulator, which must be applied in identifying required investment.[23]

We also note that currently TNSPs are not bound by the recommendations of the NTP in the NTNDP. While the NTP (being informed by the market operator) could suggest increased investment in the NTNDP, the TNSP makes the final investment decision. This provides a further safeguard against inappropriate investment decisions being driven by this potential conflict of interest. The exception is Victoria, where AEMO has the roles of market operator, NTP and jurisdictional planner. As a consequence, although there is still the RIT-T safeguard, the additional safeguard provided by separation of roles does not exist.

We therefore do not consider that this potential conflict of interest is a material feature of the current planning arrangements, outside of Victoria. However, it is important that an alternative planning framework does not create this conflict.

Finally, we note that the market operator could potentially have valuable insights into how the network should be planned, as a consequence of its experience in operating the market, and in particular identifying areas where there is substantive and prolonged congestion. However this input could be provided through a consultation role, without it being necessary for the same entity to undertake both planning and market operation functions.

3.4.3. Conflict of interest between TNSP as asset owner and planner

A third perceived conflict is between a TNSP making an investment decision, while also owning the asset.[24] The concern here is that the TNSP may have an incentive to 'gold plate' its network planning decisions, as it then gets to construct more assets on which it will earn a return.

We note that under the current framework, TNSPs bear liability associated with the assets they own and are subject to financial incentives. The return earned by the TNSP on its assets

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22 NER 5.6.5B.

23 See NERA Economic Consulting, Planning Arrangements for Electricity Transmission Networks: An International Review, A Report for the AEMC, April 2012.

24 The Clean Energy Council in its submission to the AEMC's First Interim Report noted that a for-profit business will act in its own interest, rather than to the benefit of the NEM, and so will distort the market and create a barrier to the realisation of the National Electricity Objective (NEO).

reflects the opportunity cost of the capital it has invested, as well as a return on the risks it is bearing. The TNSP's planning and investment decisions are therefore motivated by the liability they bear, rather than representing a conflict of interest.

The AER's economic regulation role provides oversight and financial incentives to guard against 'gold plating' by TNSPs.[25] Additionally, the RIT-T process specified in the Rules sets out procedural requirements which must be followed by the TNSP prior to it making an investment decision, and the evaluation criteria which it must apply. This provides a further oversight on the TNSP's investment decision-making.

Alternative planning arrangements should guard against giving TNSPs too much discretion in relation to the planning arrangements themselves eg, determining the evaluation criteria for investment, or advising on the reliability standards that the TNSP is required to operate under. For example, if TNSPs are advising on what the reliability standards should be, they may have incentives either to establish more lenient standards (so they can be more easily met) or, conversely, to establish more stringent standards (to justify more investment). Limiting the TNSP's discretion in relation to these matters means that the boundaries within which investment decisions are made are subject to determination by parties other than the asset owner, further reducing the scope for conflicts of interest.

3.4.4. Conflict of interest where TNSP also owns generation

There may potentially be a conflict where there are shareholders who have an ownership stake in both transmission and generation assets. In this circumstance, there is a concern that transmission decisions may be biased in favour of the generators owned by the same owner, impacting competition in the generation market.[26]

This situation has recently been considered by the MCE's (now SCER) Standing Committee of Officials (SCO) which released a consultation regulation impact statement (C-RIS) on the possible anti-competitive behaviours associated with cross-ownership of transmission and generation within the NEM.[27] While the C-RIS does not represent the final views of SCER, it examined the adequacy of current legislative protection against possible market failure and reduced generation competition that may result from cross-ownership. The C-RIS concluded that cross-ownership is not a problem currently in the NEM, and it is difficult to foresee whether it will become an issue in the future.

The C-RIS notes that is unclear whether current mechanisms in the NEM (eg, the Competition and Consumer Act (CCA)) would provide adequate protection against these

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[25] We note that the recent debate in the context of the AER's rule change proposal regarding the lack of *ex post* regulation of TNSP's actual capital spend, relates to the effectiveness of the current financial incentives in the NER, rather than a criticism of the fundamental regulatory approach (ie, under which financial incentives are applied to TNSPs through periodic price reviews).

[26] For example, through increasing the price of transmission, reducing quantity and quality of localised transmission, and reducing timeliness of transmission to competitor generators. Ministerial Council on Energy Standing Committee of Officials, Consultation Regulation Impact Statement: Separation of generation and transmission, 11 August 2011, p.iv.

[27] Ministerial Council on Energy Standing Committee of Officials, Consultation Regulation Impact Statement: Separation of generation and transmission, 11 August 2011.

competition concerns. For example, recent common law (eg, AGL v ACCC, 2003) suggests that the ACCC may face difficulties in proving 'likely' harm under the CCA before a court.

The C-RIS concludes by considering three potential options to deal with future cross-ownership concerns including: maintaining the current arrangements relying on CCA and NER; enhancing current transmission ring fencing guidelines; or inserting a generation/transmission provision in the NEL. We understand that a final RIS has not been finalised or released, as it is dependent on a number of review processes currently underway, including the AEMC's Transmission Frameworks Review.

3.5. Principle 5: Maximise net benefits from reform

Principle 5: Maximise net benefits from reform.

The fifth principle is that any alternative framework should maximise the net benefits from reform. That is, the benefits achieved from the reform less the costs associated with implementing reform should be maximised.

This principle implies that simpler reforms are preferable, since they will have lower implementation costs. It also implies that reforms should be no more than necessary to address the issue being targeted: ie, the coordination of planning to ensure that the identification of investment options is not limited by jurisdictional boundaries.

It is also important that implementation costs should be considered in the light of the status quo. This includes that fact that there are currently five TNSPs operating in the NEM on a for-profit basis, under a range of ownership structures, including government ownership (TransGrid, Powerlink and Transend) and private ownership (SP AusNet, ElectraNet). Consideration of the status quo includes that there is a division between the NTP responsible for long term strategic planning, and jurisdictional planners responsible for short-term detailed planning. It also means we need to have regard to the alternative planning model which has been adopted in Victoria, where AEMO is an independent, not-for-profit planner-procurer and SP AusNet does not have a planning role.

It is important to recognise that arrangements cannot be designed from a clean slate. We note that this may present insurmountable obstacles in the options contemplated.

3.6. Principle 6: Allocate risk to the party best able to manage risk

Principle 6: **Allow risk to be allocated to the party that is best able to manage the risk.**

The issues that arise from this principle for the party to which a risk has been allocated are:

- whether that party has adequate resources (including through insurance) to bear the risk;
- the party's ability to manage the risk is affected where other parties are involved in decision making relevant to the management of that risk;
- however, where risks are removed or diluted, this affects the incentive for the party to effectively manage that risk.

In the context of network planning, the following considerations arise:

- TNSPs face risks of legal liability in relation to the operation of their networks;
- decisions regarding network planning will (or at least should) flow through to transmission investment decisions, which investments in turn determine (and therefore constrain) the assets and options available to a TNSP to operate its network;
- this liability is imposed on the TNSP as the asset owner or operator, and in most cases it would be difficult to seek to impose liability in respect of earlier planning decisions.

The following paragraphs in this section set out the main types of legal liabilities faced by TNSPs and the limitations on these.

Broadly, there are four types of legal liabilities to which a TNSP is exposed.

3.6.1. Failure to meet a regulatory/legal standard

Jurisdiction-specific reliability standards are located in different types of instruments in each jurisdiction, and breach of such standards has different consequences under different state laws, as discussed in section 6.5.2.

Additionally, the NER contain a number of provisions regarding compliance with technical standards:

- NSPs (AEMO in Victoria) must comply with the power system performance and quality of supply standards described in schedule 5.1 and in accordance with a connection agreement (r 5.2.3(b), Sch 5.1);
- NSPs must notify AEMO where provisions of a connection agreement vary the technical requirements set out in the schedules to NER Chapter 5 (r 5.2.3(c));
- NSPs[28] must operate their part of the grid to standards specified in rule 5.2.3(e1)) ;
- NSPs have certain obligations regarding equipment standards (r 5.2.3(g)).

Each of the above provisions is a civil penalty provision, meaning a civil penalty of up to $100 000 must be paid by a corporation that breaches it, plus up to $10 000 for every day during which the breach continues.[29]

NSPs must also comply with 'applicable regulatory instruments' (r 5.2.3(f)).[30] By virtue of this provision, certain reliability standards imposed in state jurisdictions (i.e. those which fall

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[28] In Victoria, paragraphs (1), (3) and (4) of rule 5.2.3(e1) apply to SP AusNet by virtue of rule 5.1.2(g)(1), such that SP AusNet must arrange for: (1) the management, maintenance and operation of its part of the national grid; (3) the management, maintenance and operation of its network to minimise the number of interruptions to agreed capability at a connection point; and (4) restoration of the agreed capability at a connection point on or with that network as soon as reasonably practicable following any interruption. But paragraph (2) of that rule does not apply to SP AusNet (it is not clear whether it therefore applies to AEMO by virtue of rule 5.1.2(d)(2) – we think it must): NSP must arrange for operation of its network such that the fault level at any connection point on or with that network does not exceed the limits that have been specified in a connection agreement. Rule 5.2.3(e1) is a Civil Penalty Provision.

[29] Civil penalty provisions referred are identified in the National Electricity (South Australia) Regulations (cl 6(1), Schedule 1) (***NESA Regulations***) for the purposes of the definition of 'civil penalty provision' contained in the NEL s 58 at para (i).

[30] The definition of 'applicable regulatory instruments' includes: 'All laws, regulations, orders, licences, codes, determinations and other regulatory instruments (other than the *Rules*) which apply to *Registered Participants* from time to time, including those applicable in each *participating jurisdiction* as listed [in the definition], to the extent that they regulate or contain terms and conditions relating to access to a *network*, *connection* to a *network*, the provision of

within the definition of an applicable regulatory instrument) are enforceable under the NER, and failure to comply with such standards is a civil penalty provision.

3.6.2. An actual service interruption (caused by transmission)

In respect of service failures relating to the operation of the transmission network, TNSPs as operators of the transmission network may be liable (other than in respect of a breach of the NER):

- to pay damages under contracts with distributors, generators or large customers if there has been a breach by the TNSP of an obligation provided for in such contracts;
- to pay damages in negligence for breach of any duty of care owed to a person (breach of an NER performance standard or a jurisdictional reliability standard may be indicative of a breach of common law duty).

However, such liability is subject to statutory exclusion of liability for:

- AEMO in respect of any AEMO function under the NEL or NER (i.e. including its declared network functions in Victoria), unless done in bad faith or through negligence (subject to statutory liability caps[31]) (NEL s 119(1));
- NSPs in respect of any acts or omissions in the exercise of 'a system operations function or power',[32] unless done in bad faith or through negligence (subject to statutory liability caps[33]) (NEL s 119(2)); and
- a registered participant (including a TNSP) for any failure to supply electricity, unless done in bad faith or through negligence, to the extent any such exclusion or cap on liability has not been modified or excluded by contract (NEL ss 119(5), 120(2)).

In respect of any legal action in negligence or contract as a result of service failures in the operation of the transmission network, it is the TNSP in its capacity as operator of the electricity assets that would be the primary risk-facing entity. Liability of TNSPs for service interruption is typically provided for in connection agreements and is therefore (in addition to any negligence action in tort that may be available) a contractual matter between the relevant

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network services, *network service* price or *augmentation* of a *network*' (NER Ch 10). The definition goes on to list certain jurisdiction-specific instruments, which would incorporate at least some of the jurisdiction-specific instruments discussed in section 6.5.2.

31 Any liability of AEMO under NEL section 119(1) or NSPs under section 119(2) for negligence is capped (other than in the case of death or bodily injury) at an amount of $2 million for each person who suffers loss, or a greater amount if applicable subject to an annual limit on the NSP's aggregate liability for negligence events of $100 million: (NEL s 119(3)-(4); NESA Regulations reg 14(1)(c)-(e)).

32 A 'system operations function or power' is defined to mean 'a function or power prescribed as a system operations function or power' (NEL s 119(7)). The only functions or powers so described in the NEL or NER are those described in the section of the NER entitled 'Power system operations', which encompasses AEMO's obligations to:

> 'manage the day to day operation of the *power system*, using its reasonable endeavours to maintain *power system security* in accordance with [Chapter 3, subject to Chapter 4]' (NER cl 3.2.3(a)); and
>
> 'perform *projected assessment of system adequacy processes* (*PASA*) in accordance with rule 3.7, *publish* the details of these assessments in accordance with rule 3.13 and implement an escalating series of *market* interventions in accordance with [Chapter 3] to maintain *power system security*' (NER cl 3.2.3(b)).

33 See footnote 31, above.

participant and the TNSP (the above statutory limitations would apply to any such contractual liability to the extent they have not been modified or excluded as per NEL ss 119(5) or 120(2)). It is not uncommon for TNSPs to seek to exclude all liability for negligence on their part.

By contrast, an entity engaged in a transmission network planning function is unlikely to be found liable (in that capacity) for service interruptions:

- in negligence, because the ‘advisory’ nature of planning functions under the NEL and NER (i.e. TNSPs need only take account of relevant plans in making investment decisions) would make it difficult for a downstream customer who suffers loss to prove that the entity owed them a duty of care (in their capacity as a network planner) and/or that any breach of duty caused their loss;
- in contract, because there would not be any relevant contracts in place between a customer and the relevant planning entity (if different from the TNSP).

3.6.3. Breach of an NER provision

Aside from system performance and reliability standards (referred to above), the NER contain many obligations applicable to: TNSPs in a planning capacity;[34] the NTP; and TNSPs in relation to investment decisions and operations. Some such provisions are civil penalty provisions.[35]

3.6.4. Payment increment/decrements under the STPIS incentive scheme

TNSPs are also exposed to payment increments and decrements in respect of certain performance obligations imposed pursuant to the Service Target Performance Incentive Scheme (STPIS) incentive scheme.[36] The current STPIS scheme has two components:[37,38]

- service component – covering network availability and reliability parameters; and
- market impact component – designed to provide an incentive to improve the availability of the transmission system at times and in relation to those elements of the network that are most important to determining spot prices.

Importantly, the payment increments and decrements under the STPIS are subject to caps. TNSPs can receive:

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34 In Victoria, such obligations are split between SP AusNet and AEMO as part of AEMO's declared network functions.

35 See footnote 29, above and surrounding text.

36 NER 6A.7.4.

37 AER, Electricity transmission network service providers: Service target performance incentive scheme, March 2011.

38 We note that both the service and market impact components currently apply to SP AusNet in Victoria, despite the difference in the roles and responsibilities of SP AusNet compared with TNSPs in the other NEM jurisdictions. SP AusNet has previously commented that it has a “more limited ‘toolkit’ for responding to incentives than TNSPs in other states who may make planning as well as operational changes to improve network performance and reliability in response to the STPIS”. In addition to the STPIS, SP AusNet is also subject to the Availability Incentive Scheme (AIS), which is applied by AEMO. SP AusNet has commented that there is “considerable overlap between AIS and both the service and market components of the STPIS in terms of the performance measures and operational behaviors that are targeted.” See: SP AusNet, Transmission STPIS Issues Paper Submission, 11 November 2011.

- a financial bonus/penalty of up to +/-1 per cent of its Maximum Allowed Revenue (MAR) under the service component; and
- a financial bonus of up to 2 per cent of its MAR under the market impact component (ie, it cannot face a penalty under this component).

3.7. Principle 7: Be clear and transparent in approach

Principle 7: Be clear and transparent in approach.

Principle 7 is that any proposed transmission planning arrangements should be clear and transparent in approach. The arrangements should explicitly incorporate a culture of transparency and clarity. This facilitates participation (and therefore contributes to coordinated outcomes), since clarity ensures that people are more likely to understand the planning process, and so participate.

Clarity and transparency also ensure that it is easier to assess whether coordination is being achieved or not. Given that this is the focus of these arrangements, it is important to make sure this can be assessed.

Related to this is the need to ensure that procedures to deal with any disputes that may arise are clearly set out. Every institution in the planning framework may not agree with each other (indeed, this is likely as a result of the desirable tension), but it is important for any disagreements to be public and transparently resolved. This allows independent oversight and monitoring of these disputes.

3.8. Principle 8: Does not create barriers to connection

Principle 8: Does not create barriers to connection.

Principle 8 is that the alternative planning framework should not create barriers to connection, for either generators or large customers. Connection should be timely for both of these parties.

Planning arrangements are likely to better facilitate timely connection, where there is a single point of contact, rather than the connecting parties having to deal with multiple parties.

3.9. COAG Principles

We note that there are also Council of Australian Governments (COAG) principles that are relevant to the development of an alternative transmission planning framework. These principles were developed following the recommendation from ERIG that a NTP be established. Following the ERIG review, COAG agreed to ask the MCE to (amongst other things) develop a detailed implementation plan for the establishment of a national transmission planning function. COAG agreed to the following principles, which were also contained in the ToR that the MCE (now SCER) provided to the AEMC, resulting in the detailed development of the NTP.[39,40,41]

Accountability for jurisdictional investment, operation and performance will remain with transmission network service providers.

Where possible, the new regime must at a minimum be no slower than the present time taken to gain regulatory approval for transmission investment.

The new regime must not reduce or adversely impact on the ability for urgent and unforeseen transmission investment to take place.

We have had regard to these COAG principles in developing the alternative framework.

3.10. Summary

In summary we have identified eight principles that have guided our development of an alternative transmission framework, specifically:

1. ***Promote transmission system investment decision-making on a coordinated basis to maximise net market benefit (defined as the benefit to all those who produce, consume and transport electricity in the NEM);***
2. ***Allow for both local input and a strategic perspective;***
3. ***Allow the use of incentives to promote efficient investment decisions;***
4. ***Minimise conflicts of interest;***
5. ***Maximise net benefits from reform;***
6. ***Allow risks to be allocated to the party that is best able to manage them;***
7. ***Be clear and transparent in approach; and***
8. ***Does not create barriers to generator investment.***

Additionally, we also have regard to the following COAG principles:

Accountability for jurisdictional investment, operation and performance will remain with transmission network service providers.

Where possible, the new regime must at a minimum be no slower than the present time taken to gain regulatory approval for transmission investment.

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39 MCE, Terms of Reference to AEMC on National Transmission Planner, 3 July 2007.

40 COAG, COAG National Reform Agenda, Competition Reform April 2007.

41 Note that the COAG also agreed that: the roles of VENCorp in Victoria and ESIPC in South Australia, in regard to those jurisdictions, need not be changed and the new arrangements will not impose inefficient restrictions requiring additional resources; and the commercial arrangements relating to Basslink in its capacity as a merchant interconnection should not be altered.

The new regime must not reduce or adversely impact on the ability for urgent and unforeseen transmission investment to take place.

Next we consider several, alternative institutional structures which could be reflected in the alternative transmission planning framework, and consider the extent to which the above principles are likely to be met under each of these structures (step 4).

4. Alternative Institutional Approaches

The AEMC's First Interim Report[42] identified four preliminary options for alternative transmission planning arrangements. These options represent a range of different approaches to assigning the institutional roles and responsibilities associated with network planning.

As the next step in identifying an alternative planning framework, we have considered the appropriateness of a number of different institutional approaches, drawing on the AEMC's earlier options as a guide. Specifically we have considered:

- a for-profit joint venture, comprised of all current TNSPs;
- a not-for-profit organisation, comprised of representatives from all current TNSPs;[43]
- a NEM-wide, not-for-profit transmission planner and procurer; and
- a national body interacting with individual TNSPs across the NEM.

We consider the appropriateness of each of these different institutional approaches below, and in particular how well each approach may be expected to meet the principles set out in section 3.

4.1. Joint Venture

Submissions to the AEMC's First Interim Report generally viewed the joint venture option as difficult to implement, but possibly a long term goal for the planning and operation of the inter-connected transmission network.

4.1.1. Rationale for joint ventures

Joint ventures are used commonly in large resources projects and other investments as a means for parties to pool their resources in order to undertake an investment that an individual party would not have been prepared to undertake on its own, for example due to the size of the investment, risks involved or expertise required. The parties to the joint venture will share in the product produced by the joint venture or the profit which is generated by the joint venture.

Each party to a joint venture will have an ownership interest in the joint venture (either through shares or direct ownership in the assets on an undivided basis, depending on the joint venture structure). The ownership interest will reflect the respective investments made by the joint venture parties. The ownership interest will, in turn, determine for each joint venture party its ability to influence decisions and its share of the products or profits generated by the joint venture.

The joint venture's governance and decision making arrangements are areas for negotiation between majority and minority joint venture parties, but commonly many decisions of the

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42 AEMC, First Interim Report: Transmission Frameworks Review, 17 November 2011.

43 This institutional approach could be considered a 'hybrid' of options 1 and 4 identified by the AEMC in its First Interim Report.

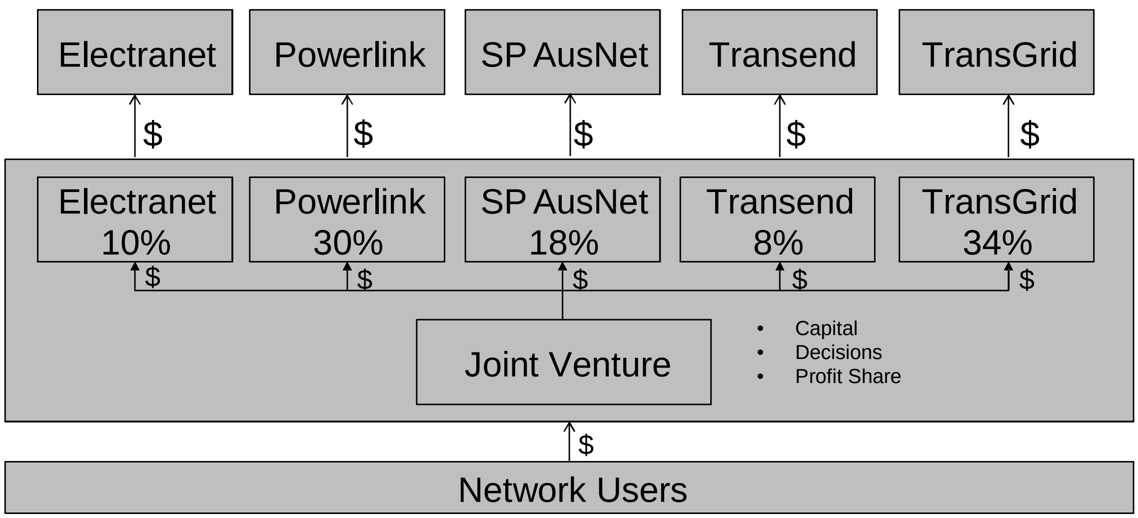
joint venture will be made on a simple majority basis, which may give one of the parties the ability to control those decisions, with only certain decisions reserved for a higher threshold (such as 75% or 90%) to provide protection to minority participants.

4.1.2. Joint venture structure

There are many different ways in which a TNSP joint venture could be structured.

For the purposes of this report, we have developed a 'strawman', to demonstrate the type of fundamental issues that would need to be considered in relation to establishing the TNSP joint venture. The strawman is illustrated in Figure 4.1 and discussed in more detail below.

Figure 4.1
Potential Structure of Joint Venture



The AEMC's First Interim Report indicated that some of the basic features of the joint venture would be that:

- the joint venture would contract with distributors, generators and customers for the provision of transmission services;
- the joint venture would have full responsibility for both network planning and making investment decisions;
- the joint venture would operate on a for-profit basis, would be subject to revenue regulation by the AER and would be responsible for ensuring that all obligations, including reliability standards were met;
- individual TNSPs would retain physical ownership of the networks, would be responsible for design and delivery of investments and would provide network services to the joint venture to enable the joint venture to provide network services to the network users.

Accordingly, the joint venture itself would not own the physical assets comprising the transmission network. Rather the underlying assets of the joint venture would be the service contracts with each TNSP, which would provide the joint venture with the ability to earn revenue by contracting with network users.

One way of considering the formation of the joint venture would be to treat each TNSP's RAB as its initial investment in the joint venture, thus determining its respective ownership interest in the joint venture. For illustration purposes only, we have used the opening RAB for each TNSP's most recent revenue determination to derive the percentage interests set out in Figure 4.1 (noting the inconsistency arising from the current staggered timetable for TNSP revenue determinations). We have also limited the strawman to the five main TNSPs, but consideration would also need to be given to the involvement of the owners of Murraylink, Directlink and any contestable transmission works constructed in Victoria to date, as joint venture participants and/or service providers to the joint venture.

As noted, the ownership interests have implications for decision making and profit share earned by the TNSPs.

4.1.2.1. Decision making

The percentage interests set out above provide an indication of how decision making may operate within the joint venture.

None of the TNSP participants has a clear majority, so even for decisions requiring a simple majority vote, it would be necessary for at least two of the TNSPs to vote in favour of that decision. For example, TransGrid and Powerlink would have a combined interest of more than 50%, and TransGrid and SP AusNet would have a combined interest of more than 50%; therefore, TransGrid may be able to control decision making, assuming it is able to negotiate support either generally or on a case by case basis from either Powerlink or SP AusNet. In contrast, if Powerlink or SP AusNet did not have TransGrid's support for a decision, they would need to have the support of not only each other but also of either ElectraNet or Transend. ElectraNet and Transend would not have the ability to block decisions at either a 75% or 90% threshold, and would therefore only have a veto right over any decisions requiring unanimity. However, an approach requiring unanimity on all investment decisions would be extremely time consuming.

Depending on where the thresholds are placed, a deadlock breaking mechanism may also be appropriate – for example, an investment decision may be made with 75% approval, but if 50% approval is given then the investment decision can be referred to an independent expert, and if the expert considers the investment should be made, it may proceed. Again, this would add time and complexity to the process.

Another approach would be to provide that, within the joint venture, investment decisions for each jurisdiction are to be made by the TNSP which owns the assets in that jurisdiction after consultation with the other TNSP participants, but the costs and revenues associated with that investment would then be shared by all TNSP participants according to their proportionate ownership interest. Such an approach would not depart significantly from the current arrangements in respect of decision making, other than by providing a forum for consultation, but would effectively require all TNSPs to be bound to the cost and revenue consequences of a decision in respect of which their role is limited to a right of consultation.

4.1.2.2. Profit sharing

Under the strawman joint venture structure described in Figure 4.1, TNSPs would earn revenue from two sources.

The first source would be the revenue earned from providing services to the joint venture using the physical network owned by the relevant TNSP. This revenue would remain linked to the value of the TNSP's particular assets. However, it is to be expected that the return on investment would be less than the return allowed by the regulator for the joint venture, on the basis that, as a profit making enterprise, the joint venture will seek to ensure that its costs (including the service fees paid to the TNSPs) are less than its revenue.

The second source of revenue to TNSPs is through a share in the profit of the joint venture. If the joint venture is structured so that each TNSP shares in the costs and revenues of the joint venture on the basis of its respective proportionate interest, these interests would not change over time as a result of the investment made in the particular TNSPs' networks. This would lead to a divergence over time between the value of the TNSP's network and its profit share in the TNSP joint venture.

While a different structure could be adopted, such as requiring the TNSP joint venture participant to bear all of the costs of, and derive all of the revenues associated with, investment in its region, this would move away from the benefit of a shared approach to the transmission network which would be sought to be achieved through implementation of a joint venture.

Accordingly, depending on the way in which fundamental aspects of the joint venture are structured, this option could result in TNSPs profitability being quite different to the profitability that they might expect under the current individual ownership structures.

4.1.3. Joint venture implementation

A joint venture as described above could be implemented by agreement between the TNSPs and their shareholding Governments.

The extent to which the TNSPs and Governments have an incentive to do so would depend upon development of the proposed joint venture structure and an analysis by each party of the advantages and disadvantages of the structure from their perspective.

We have not given detailed consideration to the way in which this structure would operate in Victoria, given the current division of roles between SP AusNet and AEMO. SP AusNet's role may be similar to the TNSP service provider in the strawman set out above, expect that SP AusNet currently earns a full regulated revenue for its investment. However, AEMO operates on a not for profit basis and, as such, does not sit well in the proposed structure which envisages a profit making body to plan and make investment decisions.

It may be possible for the participating jurisdictions, if they all agree with the approach, to legislate in order to require the establishment of the joint venture. However, this potentially gives rise to sovereign risk issues in Victoria and South Australia, where the TNSPs have been privatised under the current model of individual ownership. We have not investigated this issue which we consider is beyond the scope of this report, but note it would require detailed consideration if this option was to be pursued other than on the basis of agreement between all parties.

4.1.4. Application of principles

We consider that this proposed structure fails to meet principle 5, which is to maximise the net benefits of the reform on the basis that:

- it goes further than we consider necessary in order to address the relevant issues ie the coordination of planning to identify all relevant investment options (including those in other regions) and removal of current conflicts of interest (primarily the role of AEMO as both the NTP and Victorian jurisdictional planner); and
- implementation costs are likely to be very high.

In terms of the other principles, we consider it may also fail to meet:

- principle 7 (be clear and transparent in approach) – as the planning and investment decisions would be undertaken within the joint venture structure, rather than facilitating transparent coordination between TNSPs as in the alternative structure proposed in this report; and
- principle 8 (does not create barriers to connection) – connection for a network user is likely to require the involvement of both the joint venture and the individual TNSP that is making any necessary investment. The involvement of multiple parties in the connection process adds to its complexity, affecting the timeliness of the connection process and creating potential barriers to investment.

4.2. A not-for-profit 'joint TNSP' body

We have identified a number of practical difficulties associated with the establishment of a full, for-profit, joint venture body. Given these, one alternative would be to establish an alternative form of 'joint TNSP' body. This could be a non-incorporated, not-for-profit joint TNSP body.[44] This would be easier to establish, and so would mitigate some of the difficulties detailed above.

This form of joint TNSP body could be established by means of a requirement set out in the NER (ie, a rule requiring all TNSPs to participate in this joint body). It would therefore be administratively simpler to establish that the for-profit joint venture. The joint body could comprise representatives from all TNSPs within the NEM, in an institution akin to a 'joint committee' or 'Board of Governors'.

One possible allocation of responsibilities under this approach would be for the joint TNSP body to be responsible for short-term planning (ie, the APRs) and project specific planning (eg, the RIT-T). The NTP, as a continuing separate entity, could still undertake the long term strategic planning (ie, the NTNDP). The individual TNSPs would continue to own the network in their region.

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[44] We note the previous existence of the Inter Regional Planning Committee (IRPC). The key goal of the IRPC was to coordinate inter-network planning in the NEM. It was comprised of members of NEMMCO (the predecessor to AEMO), a representative for each jurisdictional planning body and any other members invited by NEMMCO. See: Inter-regional Planning Committee, Terms of Reference.

The establishment of a not-for-profit joint body would circumvent some of the problems identified above with a for-profit joint venture. As the individual TNSPs would retain ownership of their individual networks, there would be no need to determine issues such as the capital structure and profit share for the joint body. However, this form of institutional approach still raises a number of practical difficulties.

First, is deciding which institution would have responsibility for the investment decision. There are at least two possibilities. One is that the joint TNSP body could be given responsibility for investment decision-making. However, given the proposed nature of the body, it would not seem appropriate for it to assume risk and liability for the performance of the network. Rather, under this approach the individual TNSP would still retain liability, even if it was not the party formally making the investment decision. This is inconsistent with principle 6 – ensuring that risks are allocated to the party best able to manage those risks.

An alternative is for the TNSP itself to make the investment decision. However, this introduces a disconnect between the party undertakes the planning function (ie, the joint TNSP body), and the party making the investment decision. This has the potential to result in less than optimal outcomes, in the event that the TNSP chooses to make a different investment decision to that implied by the project-specific planning conducted by the joint body. This is inconsistent with principle 1 – ensuring that national coordination of planning occurs to maximise net benefits.

Relevant to this point is the issue of how decisions would be made within the joint TNSP body. There are three broad options for how joint decision-making could be addressed:

1. consensus – all TNSPs involved in the joint body would need to agree;
2. affected TNSP overrule – the TNSP that owns the network in the jurisdiction where the investment is to occur would have the final say in relation to all planning and investment-related decision in relation to their network; and
3. majority – the majority of TNSPs would need to agree.

Each of these different decision-making options has their own potential problems.

Requiring consensus could be expected to prolong planning times, in order for all TNSPs to come to an agreement. This would contravene one of the COAG principles ie, planning times should take longer than those currently.

Allowing for an ‘affected TNSP overrule’ would likely result in the same outcomes as currently. This is because the same individual TNSP that currently makes the decisions in relation to planning and investment would continue to make the decisions under this approach, albeit with the benefit of consulting with the other TNSPs through the forum provided by the joint TNSP body. However, to the extent that there is a concern that planning decisions do not currently achieve national coordination, this would not necessarily be addressed by this approach.

Finally, a requirement for a majority agreement has a number of possible outcomes. Note that in this case we have contemplated that a ‘majority’ is based on one vote per TNSP (compared to the majority based on ownership interests as discussed above), therefore requiring 3 TNSPs to agree for any investment decision to proceed. Status quo decisions may be made – to the extent that TNSPs may decide not to actively participate in the process outside of their own jurisdiction, and to instead simply agree to whatever is proposed in relation to other jurisdictions. Alternatively, TNSPs may agree to swap support – that is, TNSP A could agree to support everything TNSP B proposes, in return for TNSP B supporting projects that TNSP A wants to undertake. Both of these outcomes would result in no change from the status quo in terms of planning and investment decisions.

Majority decision-making could also result in potentially distorted outcomes. For example, TNSPs in other regions who lack detailed local knowledge could decide to take an active interest in all aspects of planning and investment decision-making in another region. This has the potential to result in an outcome being pursued that it is not in fact optimal, given local conditions. This approach would therefore not ensure that sufficient weight is given to local input – principle 2. It would also not be consistent with the COAG principle that accountability for jurisdictional investment remains with the TNSPs.

A final issue is the potentially limited incentives for the TNSPs to actively participate in this form of non-profit joint body. Planning resources are typically stretched within TNSPs, and it is important to recognise the network planning skills are a finite resource. Since the joint TNSP body is not-for-profit and non-incorporated, there would be no way to provide positive financial incentives in order to incentivise participation in the joint body. Financial penalties could be placed on the TNSPs, by making non-participation a breach of NER requirements. However this would not necessarily ensure *effective* participation by TNSPs; requiring TNSP representatives to attend meetings of the joint body does not ensure that the quality of participation at such meetings. It is therefore likely that it would be difficult to meet principle 3 – ensuring that appropriate incentives are provided – under this approach.

In summary, there appear to be a number of problems with assigning planning functions to a non-incorporated, not-for-profit joint TNSP body. As a result it is likely that arrangements involving such a body would not maximise the net benefits from reform (principle 5). Importantly, the creation of such a body would also not by itself achieve the intended focus of an alternative framework, ie, ensuring that all relevant options (regardless of geographic location) are considered as part of planning activities. It would therefore be necessary to combine this institutional approach with additional, specific measures to ensure this outcome.

4.3. Single, NEM-wide, not-for-profit transmission planner and procurer

A further alternative institutional arrangement would be to establish a single NEM-wide, not-for-profit, national transmission planner and procurer. Under such an approach, the national planner/procurer could be responsible for:

- all transmission network planning across the NEM (both long- and short-term);
- all investment decisions in the NEM (both RIT-T, non-RIT-T); and
- procurement of new transmission services (including non-network services), including potentially through a competitive tender process.

Under this institutional arrangement, the planner/procurer would have responsibility and bear liability for the planning and operation of the network. As a not-for-profit organisation, this would be managed through insuring against the risks of disruption. The planner/procurer could additionally manage its risk through contractual arrangements that partially shift risk to other market participants.

The transmission network would continue to be owned by the TNSP in each region, with the potential variation that, where competitive procurement of new investment is pursued, the owner of that new investment would be the successful contractor (ie, the party who won the tender).

Currently AEMO operates as a planner/procurer for Victoria, and undertakes competitive procurement for new investment where appropriate. This model would therefore in effect roll-out the current arrangements in Victoria across the NEM. We note that not-for-profit planner/procurers are also a feature of other markets internationally, including in California, PJM, New York and Alberta. In all of these markets, the planner-procurer (known either as the Independent System Operator (ISO) or the Regional Transmission Organisation (RTO)) undertakes long-term and short-term planning functions and identifies investment needs. Once the need for the investment has been established, in PJM, New York and Alberta[45] the ISO/RTO directs transmission owners in the relevant region to undertake the investment (ie, there is no contestable process). In California the ISO also directly assigns new investment projects to regional transmission operators in the majority of cases, but does also consider competing providers in specific circumstances.[46]

It would be important under a planner/procurer approach to ensure that there is effective oversight of both the planning process and the investment decisions made by the planner/procurer. This role would be most likely filled by the AER. Even though the planner/procurer would be not-for-profit, and therefore not subject to financial incentives, it would still be subject to non-financial incentives, which may be less transparent. The governance structure adopted for the planner/procurer may go some way to ensuring that its incentives are aligned with achieving optimal outcomes for the market. However, appropriate governance is typically also combined with appropriate oversight arrangements.[47] Our international review has highlighted that not-for-profit planner/procurers in other markets are subject to regulator oversight and approval, for both their planning process and ultimately

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[45] In September 2011 the Alberta Electricity System Operator filed a proposal with the Alberta Utilities Commission (AUC) to establish a competitive process to determine who is eligible to apply for the construction and operation of investment which has been designated by the Lieutenant Governor as Critical Transmission Infrastructure. The AUC is expected to decide on the proposal in June 2012.

[46] Specifically, the California ISO (CAISO) directs specific transmission owners to undertake investment in their region where the investment is a reliability-driven project. For economically-driven or policy-driven investments, if only one project sponsor has submitted a proposal to finance, construct and own an asset included in a final Transmission Plan, and the CAISO determines that the project sponsor is qualified to do so, then the project sponsor must commence the process of constructing the asset. Where two or more project sponsors have submitted proposals, and the CAISO determines that they are both qualified, then the CAISO will engage an expert consultant to assist with the selection of the project sponsor.

[47] The AER commented in its submission to the AEMC that it was concerned about the lacks of checks and balances under this approach, since planner-procurer activities are not exposed to regulatory reset processes. AER Submission to First Interim Report: Transmission Frameworks Review, 27 January 2012.

their investment decisions. For example, in California the Federal Energy Regulatory Commission (FERC) approves the transmission planning processes of CAISO and also approves the specific investments identified by CAISO, as a consequence of its role in approving CAISO's Transmission Access Charge. We note that currently this oversight role of the planner/procurer is largely absent in Victoria – see Box 4.1.

We have identified a number of limitations associated with the single NEM-wide transmission planner/procurer model.

First, this model does not promote the minimisation of conflicts of interest – principle 4. Under this institutional arrangement there would no longer be the 'tension' that the MCE earlier determined was desirable between the longer-term strategic planning function, and the shorter-term, detailed project-specific planning. The single NEM-wide transmission planner/procurer would undertake both of these roles. As a consequence, there would be no independent 'check' on the development of the plans, and the benefit of incorporating alternative viewpoints would be lost. Importantly, as discussed in section 3.4, even though the planner/procurer would be an independent body, it would not be able to provide independent advice to itself.

Moreover, if the planner/procurer model were to be established in the NEM currently, the most likely institution to take on this role is AEMO. AEMO is also the market operator. The adoption of this model would therefore remove the current mitigation of the potential conflict of interest between the NTP and the market operator roles. The planner/procurer would make the investment decisions, and may potentially be influenced by its market operator function. This issue would need to be addressed through the governance and oversight arrangements adopted for the planner/procurer.

The second issue is the incentives on the planner/procurer. The non-profit nature of the planner/procurer means that it cannot be made subject to financial incentives, and therefore is less likely to meet principle 3. As discussed in section 3.3, all institutions have incentives. Not-for-profit institutions are still subject to non-financial incentives, which are likely to be less transparent, and may ultimately be less effective, requiring a greater degree of oversight.

Finally we note that this model would require generators and large customers wishing to connect to the network to deal with both the planner/procurer and the transmission network owner. This has the potential to create barriers to connection for both generation and customers (principle 8). We understand that currently the need to negotiate multiple connection contracts significantly prolongs the connection process.[48]

[48] These issues were noted in the NGF's submission to the AEMC's Directions Paper, and were subsequently recognised in the First Interim Report. In particular, the NGF had concerns with the complexity of multiple connection agreements – noting that up to sixteen connection agreements could be required for a single connection point. AEMC, First Interim Report, 17 November 2011, p.149.

Box 4.1
Economic Regulation in Victoria

Victoria currently operates under a planner/procurer model. Specifically, the transmission network is planned and procured by AEMO, which is a not-for-profit organisation. AEMO is not subject to a revenue determination by the AER (in contrast to its predecessor, VENCorp). AEMO is however required to submit other components of a transmission determination for AER approval, including a pricing methodology. SP AusNet, which owns and operates the bulk of the transmission network in Victoria, is subject to a revenue determination by the AER. However, this applies only to those transmission services that are for replacement/refurbishment.

At a high level, there are three types of investment expenditure that may occur under this model:

- contestable transmission services related to augmentation;[49]
- non-contestable transmission services related to augmentation; and
- replacement or refurbishment investments.

For contestable transmission services, AEMO tenders for parties to construct the relevant assets. In this case, SP AusNet (the incumbent TNSP) competes with other parties for the contract. These investments are 'non-regulated' transmission services.

The majority of augmentation transmission services are treated as non-contestable. Here, AEMO will apply the RIT-T to decide what investment is required. It then directs SP AusNet to provide the augmentation, on a non-contestable basis. AEMO and SP AusNet negotiate a contract in order for SP AusNet to carry out the work. During the regulatory period in which the asset is constructed, SP AusNet is provided with funding for the investment via contract payments made by AEMO (with the payments based on TUOS charges) and the costs and revenues sit outside the revenue cap for SP AusNet. These non-contestable projects are then added to SP AusNet's Regulated Asset Base (RAB) at the start of the next regulatory period.[50] The appropriate return on and of the investment then forms part of SP AusNet's revenue cap for prescribed services from the next regulatory period onwards.

In the case of replacement or refurbishment investments, these are treated the same for SP AusNet as for other TNSPs. SP AusNet submits a revenue proposal to the AER that details these capital investments, with the AER either approving the forecast capital expenditure allowance, or substituting its own estimate. SP AusNet is then entitled to include the approved investments in its maximum allowed revenue for the regulatory period, with actual investment rolled into the RAB at the start of the next period.

In summary, the planner/procurer model does not meet a number of the principles which we consider should guide the development of an alternative transmission planning framework. It is also likely to have significant implementation costs, given the current structure of TNSPs

[49] Projects can be constructed through competitive tendering if the capital cost of the augmentation is reasonably expected to exceed $10 million, and it can be provided as a distinct and definable service and will not have a material effect on an incumbent network asset owner.

[50] NER 11.6.21(b).

in the NEM, and would therefore be unlikely to represent the alternative which maximises the net benefits from reform (principle 5).

4.4. National body interacting with individual TNSPs across the NEM

The final institutional approach that we have considered is to have a single, national body (ie, the NTP) interacting with all individual TNSPs across the NEM. This option does not require any new institutions to be set up, since the existing NTP could expand its role to fulfil the interaction envisaged under this approach. This approach would be similar in many respects to the way in which the NTP and ElectraNet currently interact in South Australia.

The institutional approaches discussed in the previous sub-sections all involved planning decisions across the NEM being taken by a single, national body. Under this fourth approach, national coordination and national consistency would be achieved as a result of a single national body interacting on planning issues with each of the TNSPs in turn.

Under this institutional structure, the NTP could remain responsible for the long-term, strategic NEM-wide plan (ie, the NTNDP). It could also provide input to the individual TNSPs' short-term plans, specifically through providing demand forecasts and scenario inputs. The TNSPs would undertake project specific planning, and would be responsible for investment decisions. The NTP could provide advice and comment in relation to these short-term and project specific plans, targeted at ensuring national coordination. However the TNSPs would retain the ultimate responsibility for these plans, and would maintain ownership of the resulting assets and retain liability. Further, the NTP could have an advisory role in relation to economic regulation, compliance with the RIT-T and reliability setting.[51, 52]

This institutional option would have minimal implementation costs, since no new institutions would need to be created (principle 5). Some improvement in coordination across the NEM could be expected under this approach, simply as a result of having a single, nationally focused body providing advice to and interacting with all individual TNSPs. It is likely therefore that some variant of this approach would be likely to maximise the net benefit associated with moving to an alternative framework.[53]

However, this approach would be likely to be more effective in ensuring national coordination if it were to be combined with additional measures targeted specifically on the key aspects of enhanced coordination (principle 1). We also note that under this approach, the NTP and Victorian planning role would still be undertaken by a single body (AEMO),

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51 We note that AEMO advised the Essential Services Commission of South Australia (ESCOSA) in 2010 in the setting of reliability standards.

52 Grid Australia comments in its submission to the AEMC's First Interim Report that this approach would maintain independent third-party input by the NTP into investment decisions, via participation in revenue setting decisions and providing inputs into RIT-T assessments.

53 Grid Australia notes in its submission to the AEMC's First Interim Report that this type of arrangement would simplify a future move to a joint venture, if that was determined to be desirable in the future. The Major Energy Users (MEU) expressed similar sentiments in its submission ie, a regime based on the South Australian approach would provide considerable benefits with minimum costs and changes, and would also allow for potential greater change in the future (if required).

and so the benefit of having a separate body with an independent national focus could potentially be lost for that jurisdiction (principle 6).

In summary, we consider that this institutional approach appears to best meet a majority of the principles adopted to guide our assessment, and so should be considered further. However it would need to be combined with additional measures in order to effectively meet the key aims of an alternative framework.

4.5. Summary

We have considered a number of different institutional arrangements that could be adopted for the alternative planning framework. Importantly, all of these options all have limitations, including that none of them are specifically targeted at ensuring increased national coordination. In all cases, therefore, it would be necessary to combine these institutional arrangements with additional measures.

The institutional arrangement that seems to best meet the principles is that of a nationally focused planning body interacting with and advising individual TNSPs as part of their planning functions across the NEM. This approach has the benefit that it involves minimal implementation costs, since it does not require the establishment of a new institution.

We consider that, in combination with other targeted measures, this structure could achieve the specific focus of the alternative transmission planning framework, and meet the principles set out in section 3. We discuss the key features of this alternative framework in the following section (step 5).

5. Alternative Transmission Planning Framework: Nationally Coordinated Decision Making

In this section we set out at a high-level an alternative transmission planning framework, focused on ensuring nationally coordinated decision-making.

The framework builds on the institutional arrangement discussed in the previous section, of a single, national planning institution (the NTP), interacting with individual TNSPs across the NEM. The alternative framework also includes three additional components targeted at ensuring national coordination:

- coordination across TNSPs focused on ensuring that all relevant options are considered in planning decisions, regardless of jurisdictional boundaries;
- an enhanced role for the NTP in reviewing and commenting on the TNSP's draft APR's and draft RIT-T documentation, with the focus on ensuring that options in other regions are being adequately considered; and
- an enhanced role for TNSPs in the development of the NTNDP, to ensure that coordination between national and local issues occurs at the outset of the planning process.

We discuss these three components in turn below. Section 6 then discusses the allocation of roles and responsibilities under the alternative framework in detail.

5.1. Coordination across TNSPs to consider options in other regions

At a high-level, the alternative framework would include NER changes aimed at ensuring nationally coordinated decision-making by imposing a new requirement for consultation between relevant TNSPs in preparing APRs, and undertaking RIT-T and non-RIT-T assessments. This requirement is targeted at ensuring that where there are investment options that may involve assets in other regions, that these are identified and considered as part of a TNSP's planning activities.

Under this approach, when APRs are developed by TNSPs, they would need to set out whether there are options located either wholly or partly in other regions that could potentially address the identified need. These options would be identified and developed through consultation with neighbouring TNSPs. TNSPs would also be required to set out as part of their APRs if they do not consider that options in other regions would meet the identified need for the investment, where that is the case, and the reasons why. The NTP could be required under the NER to develop guidelines on assessing whether an investment need could be met by an investment in another region. These would be similar to the current guidelines on material inter-network impact, which have been produced by AEMO (and is discussed in further detail in section 6.1). TNSPs would be required to summarise in their APRs the consultation and interaction which has occurred with other TNSPs in developing their plans.

This approach would follow through to project specific plans, with TNSPs being required to consider options in other regions in both their RIT-T and non-RIT-T assessments. Where such options are identified as relevant, they would then be considered in the evaluation of the particular investment. Again, where options in other regions are not considered relevant, this would need to be documented, and reasons given for why not.

If an option in another region was identified as being the preferred option under the project specific planning, the TNSP in the other region would need to agree to be the proponent of that option (or another provider, in the event that the investment could be treated as contestable). If the option did not have a proponent, then it could not be chosen as a preferred option by the TNSP. The public identification of alternative options in other regions would be expected to provide incentives for the TNSP in the neighbouring region to agree to be a proponent for such investments. It would also be important for the economic regulatory regime to provide an incentive for TNSPs to agree to be proponents for such investments (or, as a minimum, not to provide a disincentive). This is discussed further in section 6.5.1.

We note that these suggested changes have existing precedents in the NER. There is currently a requirement in the NER for TNSP-DNSP joint planning, and for TNSPs and DNSPs to conduct annual planning reviews, in order to determine options that can address identified constraints within the network.[54] Moreover, the suggested changes are also similar to the current requirement on TNSPs to consider non-network options in the RIT-T.[55]

5.2. Enhanced NTP role

The second key element of the alternative framework is an enhanced role for the NTP, to facilitate increased coordination across the NEM, including in relation to the new NER requirements for TNSP-TNSP consultation discussed above.

Specifically, under the alternative framework:

- the NTP would review each TNSP's draft APRs, and highlight to TNSPs where it appears that there would be a benefit from coordination;
- the NTP would comment on the draft RIT-T Project Specification Consultation Report (PSCR) prepared by the TNSPs, with a focus on highlighting those areas where options in one region may help in addressing an investment need in a different region;
- the NTP would provide demand forecasts to TNSPs to be used as a starting point for the forecasts adopted by the TNSPs in their APRs, RIT-T and non-RIT-T assessments; and
- the NTP would provide an advisory role to the AER in relation to economic regulation and monitoring compliance with the RIT-T, and also to the institutions involved in the setting of reliability standards.

We note that this proposed role builds upon the current NTP role in South Australia.[56]

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[54] NER 5.6.2(b)

[55] NER 5.6.5D(b)(5).

[56] In South Australia AEMO provide demand forecasts to ElectraNet. AEMO also advised the Essential Services Commission of South Australia (ESCOSA) in 2010 on its review of reliability standards.

The NTP's role in reviewing draft APRs, would be to highlight where it appears that individual TNSPs are planning investments which have complementarities, or where it appears that an investment need could potentially be met by investment options in other regions. This role would act as a check on the TNSP-TNSP consultation requirement in the NER, and would provide a further avenue for TNSPs to become aware of what others are planning. The NTP would flag with the TNSP that it should be consulting on a particular investment with neighbouring TNSPs. We note that the NER requires all APRs to be produced by the end of June.[57] The consistency in APR timeframes across jurisdictions would facilitate this overview role by the NTP, as it would be able to review all the APRs at the same time and provide consistent comments across the NEM.

The NTP's role in highlighting areas where coordination is likely to be beneficial would be further pursued through a new role in advising on the consideration of investment options in neighbouring regions as part of the RIT-T process.

We note that the NTP's role in relation to providing input into both the APR and RIT-T processes conducted by the TNSPs would be specifically targeted at identifying areas where coordination with other TNSPs should be occurring. This targeted approach is consistent with the view previously expressed by the AEMC that the NTP should not be 'at large' to involve itself in all RIT-T proposals by TNSPs, as this would not be an efficient used of its limited resources and may affect the timeliness of the regulatory approval process.[58]

In addition, the NTP should provide a standardised set of demand forecasts to TNSPs across the NEM. This would provide a consistent starting point for the demand forecasts used in planning across the NEM. These would be in addition to the 'bottom up' demand information that is currently required to be provided by Registered Participants under clause 5.6.1 of the NER.[59] TNSPs would not be required to use the NTP forecasts, and would be able to deviate from them where local knowledge suggests this is appropriate, provided that they clearly state how and why they have deviated from the NTP's forecasts.[60] For example, TNSPs may have more specific knowledge about a particular load area or potential customer connections than is reflected in the NTP's forecast.

We note that the current practice in the NEM has been for jurisdictional governments to decide upon the question of who is responsible for demand forecasting in each jurisdiction (ie, whether it is the NTP or the TNSP or another individual). However, the rationale for government involvement in this area is not clear. It appears more appropriate for the role of

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57 NER 5.6.2A(a).

58 AEMC, National Transmission Planning Arrangements: Issues Paper, 9 November 2007, p.49.

59 We note that as part of AEMO's current additional advisory functions in South Australia it produces the South Australian Supply and Demand Outlook (SASDO) report. This provides 'top down' demand forecasts for South Australia, which AEMO then compares with the 'bottom up' demand forecasts that are produced by ETSA Utilities and ElectraNet.

60 This is similar to the current practice in South Australia. ElectraNet adopts demand forecasts from ETSA Utilities (the South Australian distributor) in its APR and RIT-T assessments, and supplements these with particular information about load and customer connections. It notes in both its APR and RIT-T assessments where this has occurred. ElectraNet also notes in its APR that it compares both the NTNDP and the SASDO demand forecasts for South Australia with the ETSA Utilities' forecasts.

demand forecaster to reside with a single national body (ie, the NTP), in order to ensure a consistent national approach in developing load forecasts.

5.3. Enhanced TNSP input into NTNDP

The third key element of the alternative framework is a role for enhanced TNSP input into the NTNDP. We understand that this would be a formalisation of existing practice. This would ensure that coordination between national and local issues occurs right at the outset of the planning process.

This enhanced TNSP input would occur through a working group, comprised of TNSP representatives from all jurisdictions, being involved in advising the NTP in the preparation of the NTNDP. This working group would comment on, and provide input to, the NTP in the development and preparation of the NTNDP. This role would complement the NTP's role in commenting on aspects of the TNSP's APRs and RIT-T applications.

6. Roles and Responsibilities under the Alternative Framework

This section details who would be responsible for undertaking the detailed roles and responsibilities relating to planning (as set out in section 2.2) under the alternative framework.

There are five key institutions involved in the alternative framework:

- the NTP;
- the 'home' TNSP', ie, the TNSP in the jurisdiction where the need has been identified - eg, if the need is to meet a reliability standard in Queensland, Powerlink would be the 'home' TNSP;
- the 'other region' TNSP' ie, a TNSP in a region other than that of the 'home' TNSP;
- the AER; and
- 'other body' eg, state regulator, AEMC etc.

6.1. Planning

The first 'high level' area is planning – Table 6.1.

Table 6.1
Roles and Responsibilities: Alternative Framework - Planning

Roles		NTP	'home' TNSP	'other region' TNSP	AER	Other body
Planning						
Long term strategic plan: NEM-wide (NTNDP)	Development of plan	**✓**	✓	✓		
	Identification of need	**✓**				
	Demand forecasts	**✓**				
	Development of scenarios (incl. generation)	**✓**				
Short-term detailed plan: regional and cross-regional (APR)	Development of plan	✓	**✓**	✓		
	Identification of need	✓	**✓**			
	Demand forecasts	✓	**✓**			
	Development of scenarios	✓	**✓**			

Note: ✓ = Primary responsibility; ✓ = Also involved

Under the alternative framework, the development of the long-term strategic plan (ie, the NTNDP) would be undertaken by the NTP, as currently. The NTP would be responsible for the development of the plan, identifying the need, undertaking demand forecasts and developing scenarios (including generation). This development could be informed by a working group of TNSP representatives, to ensure that coordination between national and local issues occurs right at the outset of the planning process.

These roles and responsibilities are indicated in Table 6.1. The 'black ticks' represent the institution that has the ultimate responsibility for each task. The 'grey ticks' represent that the institution has input into the task, but only in an advisory capacity. For example, the NTP is responsible for producing the NTNDP ('black tick'), but a working group of TNSPs representatives would advise on the development of the plan ('grey tick').

Short-term strategic planning (ie, the APRs) would be undertaken by the relevant TNSP, the same as currently. The NER would however include a requirement for TNSPs to consult with other TNSPs in developing their APRs, in order to identify whether an option in another region could also meet identified needs for investment in their own region. TNSPs would be required to summarise in their APRs the consultation and interaction which has occurred with other TNSPs in developing their plans, including where consultation has not ultimately led to identification of options.

The NTP would also have a role in commenting on the draft APRs. This includes commenting on the proposed options, and suggesting where an investment need may be able to be met by an investment in a neighbouring region, or where coordination between regions on specific investments appears likely to be beneficial. If the NTP considered that a particular investment could potentially be met by an investment in another region, and that this was not currently being considered in the APR process, it would flag this with the relevant TNSPs. This provides a check to ensure that the coordination across regions is in practice being undertaken by TNSPs, in accordance with the NER requirement. If the TNSP disagreed with the NTP's comments, it would need to include a statement in its APR setting out why it does not consider that investments in other regions are relevant in meeting a particular investment need.

The consideration of the potential for investments to be met by options in another region could be informed by guidelines. These guidelines could be developed by the NTP. Such guidelines would be similar in nature to the current guidelines that AEMO is required to publish for assessing whether a proposed transmission network augmentation is likely to have a material inter-network impact.[61] These guidelines are required under the NER to be developed in accordance with guiding objectives and principles set out by the AEMC.[62] These criteria allows for the use of professional judgment to determine whether or not there will be a material impact – however, if any level of doubt exists, then a screening process

[61] NER 5.6.3(b). These guidelines were developed by the Inter Regional Planning Committee, and are still listed as current on the AEMO website. See: IRPC, Final Determination: Criteria for Assessing Material Inter-Network Impact of Transmission Augmentation, October 2004.

[62] NER 5.6.3(c)

should be applied.[63] Considering that there is no "bright line" between when investments in other regions may be relevant and when they are not relevant, it is likely that a similar sentiment could be reflected in guidelines applied to assist this identification.

Under this alternative framework, the NTP would provide demand forecasts to the TNSP to be used as the starting point for the demand forecasts in the TNSP's short-term plans, together with load information provided by Registered Participants. The TNSP could depart from using the NTP forecasts, provided they are transparent in their APRs about doing so. This is similar to the current approach within South Australia, where ElectraNet adopts demand forecasts from ETSA Utilities (the South Australian distributor) in its APR and RIT-T assessments, and supplements these with particular information about load and customer connections. It notes in both its APR and RIT-T assessments where this has occurred. ElectraNet also notes in its APR that it compares the NTNDP and South Australian Supply and Demand Outlook (SASDO) demand forecasts for South Australia prepared by AEMO with the ETSA Utilities' forecasts.

6.1.1. Last Resort Planning Power

Another planning function that currently exists in the NEM is the Last Resort Planning Power (LRPP). This is an oversight power which has the objective of ensuring timely and efficient inter-regional transmission investment, for the long term interests of consumers of electricity.[64]

Currently, the AEMC is responsible for the LRPP. The LRPP is designed to "provide transparency and to encourage TNSPs to identify areas of the network which may need reinforcement or augmentation and test potential new transmission projects".[65] Under the LRPP the AEMC may direct one or more participants to apply the RIT-T to a potential transmission project.[66] The AEMC is required to report on the LRPP annually.

In exercising its power, the AEMC must have regard to the NTNDP for the past two years, the APRs produced by the TNSPs and any advice provided by AEMO.[67] In effect, the LRPP acts as a confirmation of the extent of coordination which is occurring between the various elements of the planning arrangements, in that it requires reconciliation between the NTNDP produced by AEMO and the later APR and RIT-T processes adopted by the TNSPs. In its 2011 report on the LRPP, the AEMC noted that each jurisdictional planning body appears to be progressing projects which adequately address all the relevant inter-regional planning issues or opportunities identified by AEMO. As such, the AEMC concluded that there was no material need for the exercise of the LRPP in 2011.[68]

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[63] IRPC, Final Determination: Criteria for Assessing Material Inter-Network Impact of Transmission Augmentation, October 2004, p.18.

[64] NER 5.6.4(b).

[65] AEMC, Transmission Frameworks Review Issues Paper, 18 August 2010, p.24.

[66] NER 5.6.4(c).

[67] NER 5.6.4(g)(2).

[68] AEMC, Last Resort Planning Power Review 2011 Decision Report, November 2011, p.ii.

We propose that under the alternative framework, the NTP would become responsible for the LRPP, rather than the AEMC. This re-allocation of roles appears appropriate, as under the alternative framework the NTP has a role in commenting on the TNSPs' draft APRs, and so will already be undertaking a review of the TNSPs' plans. In addition, the NTP itself has relevant planning expertise (through its role as NTP) which is likely to provide it with the practical experience to better direct other parties to undertake RIT-Ts.[69,70]

We note that if the LRPP role was given to the NTP, this would require a separation between the NTP and the Victorian planning function, in order for the LRPP to have applicability for Victoria. We consider this further in section 8.3.

6.2. Project specific planning/investment decision

The second high level area is project specific planning and the investment decision – Table 6.2.

Table 6.2
Roles and Responsibilities: Alternative Framework – Project Specific Planning / Investment Decision

Roles		**NTP**	**'home' TNSP**	**'other region' TNSP**	**AER**	**Other body**
Project specific planning/ investment decision						
Identification of need			✓			
Demand forecasts		✓	✓			
Development of scenarios		✓	✓			
Identification of options		✓	✓	✓		
Evaluation (RIT-T, non-RIT-T)		✓	✓	✓		
Investment decision			✓			

Note: ✓ = Primary responsibility; ✓ = Also involved

For project specific planning, the 'home' TNSP would identify the need and develop associated demand forecasts and scenarios for both the RIT-T and non-RIT-T assessments. These would be based on the scenarios developed by the NTP in the higher level planning documents (ie, NTNDP). However, the TNSP could depart from these where they have more detailed knowledge of the issues which should be taken into account (eg, where they have particular knowledge of specific load conditions or connection enquiries). TNSPs would be required to note where they have departed from the NTP's demand forecasts and scenarios.

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69 Alinta Energy set out similar sentiments in its submission to the AEMC's First Interim Report. It considered that the AEMC should give further thought to an NTP independent of AEMO holding the LRPP. It considered that the safeguards desired by the Victorian DPI would be in place through a not-for-profit planner; however, the advantages of financial incentives and local decision-making would be retained.

70 We note that currently the AEMC may request advice from AEMO (and so draw upon its planning expertise) in relation to the exercise of the LRPP. NER 5.6.4(e),

The NTP would comment on all the draft documentation throughout the RIT-T. This would include commenting on the Project Specification Consultation Report (PSCR), and the Project Assessment Draft Report (PADR). A specific process would be included for the NTP to comment on the PSCR, and the NTP may (as is already envisaged) participate in the consultation process for the PADR. The NTP's review role would focus on advising on the demand forecasts, scenarios and the consideration of investment options located in other regions. The TNSP would not be bound by the NTP's comments, but would be required to consider them in its final documentation.

In terms of developing options, the 'home' TNSP would be ultimately responsible for developing the different options for assessment in both the RIT-T and non-RIT-T assessments. As discussed in section 5.1, there would be a new NER requirement for the TNSP to consider investments located in other regions that may also address the identified need, ie, for investments affecting major transmission flow paths or reliability driven investments situated near jurisdictional borders. If the TNSP considers that an investment need may be met by an option in another region, then it will consult with that 'other region' TNSP. Accordingly, the 'other region' TNSP may advise on potential options. Alternatively, the 'other region' TNSP could also propose potential options to the 'home' TNSP. If an 'other region' TNSP option is considered appropriate, the 'other region' TNSP may be involved in the more detailed development of the option for assessment, including providing information on the costs of the options.

We note that currently the NER does not preclude a credible option in a RIT-T assessment being a transmission investment undertaken by another TNSP.[71] However, the proposed NER changes included as part of the alternative framework would make this possibility explicit, and would require the TNSP to actively comment on whether such credible options existed for a particular RIT-T application. If the 'home' TNSP did not consider that there was a potential option in another region, then its assessment would need to state this, together with the reasons why.

The NTP will also have an advisory role in suggesting options that could be met by investments in different regions, in order to ensure that coordination is facilitated.

Importantly, the investment decision would be made by the 'home' TNSP. Even if the preferred option under the assessment was an option that was wholly located in the 'other region' TNSP's network, the decision would still be made by the 'home' TNSP.

For an 'other region' TNSP option to be chosen as the preferred option, the 'other region' TNSP would need to be willing to act as a proponent for the project ie, demonstrate that it is sufficiently committed to building the investment. If the 'other region' TNSP was not willing to be a proponent, then this investment could not be chosen as a preferred option. This reflects the current requirement in the NER in relation to credible options for reliability corrective action under the RIT-T, ie, they must have a proponent to be selected as the

[71] NER 5.6.5D. TNSPs are required to consider all reasonable options which could be reasonably classified as credible options, taking into account factors including: ownership, whether the credible option is intended to be regulated, and whether it is a network or non-network option

preferred option at the PADR stage.[72] However the transparency of the RIT-T process would be likely to provide sufficient moral suasion to encourage other TNSPs to be a proponent for the option, provided that they were not financially disadvantaged by doing so (see section 6.5.1).

If moral suasion does not turn out in practice to be sufficient, thought may need to be given to imposing obligations on TNSPs as part of the NER. However we do not consider that obligations be imposed on TNSPs in the first instance, before it is clear that moral suasion is insufficient in practice. Imposing an *obligation* on an 'other region' TNSP to act as a proponent, would result in the RIT-T assessment needing to be conducted jointly between the 'home' and 'other region' TNSPs, (ie, similar to current practice with interconnector assessments), since both TNSPs would need to agree on the analysis and evaluation presented. This would likely prolong the time associated with conducting a RIT-T assessment, in contrast with the COAG principle that, where possible, the time taken to gain regulatory approval for investment should be no slower than the present time. We note that while maximum timeframes associated with RIT-T assessments are set out in the NER, TNSPs may in practice complete their assessments in a shorter timeframe. This may be less likely where the assessment is jointly conducted.

There would also be a requirement in the NER for a similar TNSP-TNSP coordination process to occur in relation to non-RIT-T investments. The NER could require investments not covered by the RIT-T to include consideration of options that could be partially or wholly located in another region.[73] We note that the non-RIT-T assessment of options is less transparent than RIT-T assessments, and is not subject to the same public consultation requirements. However, we also note that the coverage of RIT-T projects is extensive, and many investments will be assessed through this route. Investments considered through the non-RIT-T process are likely to be confined to those relating to:

- maintenance or replacement;
- reconfiguration of the network;
- augmentation to provide market benefits, where the estimated capital cost of the augmentation component is below $5 million; or
- to meet service standards or to increase net market benefits where the estimated capital cost of the most expensive option to meet this need is below $5 million.

It appears unlikely that investments to meet these drivers are likely to be met by options located another region. For example, replacement expenditure would likely be constrained to a replacement of the asset in the same region as the existing asset. However, the NER could require the AER to consider the extent of TNSPs' coordination in planning for these non-RIT-T investments as part of its revenue determinations.

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[72] NER 5.6.6(l).

[73] This change could potentially be achieved by amending NER 5.6.5C(d).

6.3. Implementation of investments

The third 'high level' area is implementation of investments – Table 6.3.

Table 6.3
Roles and Responsibilities: Alternative Framework – Implementation of Investment

Roles		NTP	'home' TNSP	'other region' TNSP	AER	Other body
Implementation of investment						
Obtaining planning permission			✓			
Obtaining easements			✓			
Outage planning			✓			
Detailed design#			✓	*		
Procurement of materials			✓			
Procurement of resources			✓			
Management of site works			✓			
Commissioning			✓			

* If the 'other region' TNSP was prepared to become the proponent for the investment, then these roles and responsibilities would shift to the 'other region' TNSP.
# Note that if the 'other region' TNSP was the proponent, the 'home' TNSP would still need to provide input into the detailed design of the investment in order to ensure that it meets the relevant jurisdictional standards.

The roles and responsibilities associated with the implementation of the investment (eg, obtaining planning permissions, easements, outage planning, detailed design, procurement, management of site works and commissioning) would all be undertaken by the 'home' TNSP itself, if the 'home' TNSP was the proponent for the investment.

If the 'other region' TNSP was the proponent for the investment, then these roles and responsibilities would all shift to the 'other region' TNSP. The 'home' TNSP would however still need to provide input into the detailed design of the investment in order to ensure that it meets the relevant jurisdictional standards. For example, if the investment was built to meet reliability standards in NSW, but the preferred option was in Queensland, the investment would need to be built in a manner that ensured that NSW reliability standards were met.

6.4. Ownership, O&M, and liability

The fourth high-level area is that of ownership, operating and maintenance and liability – Table 6.4.

Table 6.4
Roles and Responsibilities: Alternative Framework – Ownership, O&M and Liability

Roles		NTP	'home' TNSP	'other region' TNSP	AER	Other body
Roles and responsibilities						
Transmission asset ownership			✓			
Maintenance			✓	*		
Operation			✓			
Responsibility/liability			✓			

* If the ''other region' TNSP was prepared to become the proponent for the investment, then these roles and responsibilities would shift to the 'other region' TNSP.

Under the alternative framework, the 'home' TNSP would be responsible for the ownership, maintenance and operation of the transmission asset if it is the proponent. Importantly, it will also be liable for the asset, and so bear the associated risks.

We note that if the proponent TNSP is an 'other region' TNSP, then the ownership, maintenance and operation roles and responsibilities will shift to the 'other region' TNSP. It will be required to maintain it in accordance with the relevant standard, with this governed through a contract with the 'home' TNSP.

However, the responsibility/liability will remain with the 'home' TNSP no matter which TNSP is the proponent. If a breach of service standard occurs, ultimately the 'home' TNSP will be held responsible and liable.

If the 'other region' TNSP wishes to be a proponent for an investment, as part of meeting the 'home' TNSPs reliability obligations, it must also be willing to accept any liability that may arise from its contribution to a reliability of supply failure. This would be managed through a contract between the 'other region' TNSP and the 'home' TNSP pursuant to which:

- the 'other region' TNSP is obliged to operate and maintain the assets so as to enable the 'home TNSP' to meet the reliability standards and other relevant obligations applicable in the jurisdiction of the 'home' TNSP; and
- the 'other region' TNSP indemnifies the 'home' TNSP for any liability of the latter arising from a failure by the former to operate and maintain the assets as required.

We note that this is similar to the current contractual requirements where there is a non-network proponent.[74]

[74] For example, see: Transend, Kingston area augmentation, Project Specification Consultation Report, 2011, p.13.

The mechanism we propose relies on the two TNSPs voluntarily reaching agreement on these matters. Given the potentially more risk averse nature of regulated monopolies, this factor could inhibit the implementation of investments identified through the alternative planning framework. If, after a period of operation of the proposed framework, it became apparent that TNSPs were failing to undertake inter-jurisdictional investments in the desired manner because investing TNSPs were unwilling to accept such risks, the NER could be amended to require investing TNSPs to make such investments and accept these risks.

6.5. Regulation and Standards

The fifth high level area is that of regulation and standards – Table 6.5.

Table 6.5
Roles and Responsibilities: Alternative Framework – Regulation and Standards

Roles		NTP	'home' TNSP	'other region' TNSP	AER	Other body
Regulation and Standards						
Revenue regulation	Economic regulation				✓	
	Advisory role to economic regulator	✓				
	How is asset owner compensated? (ie, economic regulation or contract payment)		economic regulation	primarily economic regulation		
Compliance with network planning requirements in NER	Compliance monitoring				✓	
	Advisory role to compliance monitor on RIT-T	✓				
Network reliability standards	Setting of standards					✓
	Advisory role in relation to standards	✓				

Economic regulation and compliance monitoring would be undertaken by the AER, the same as currently. The NTP could have an advisory role in relation to each of these activities, as they are not responsible for undertaking the actual investment decisions.

We consider the approach to economic regulation under the alternative framework in more detail below.

6.5.1. Economic regulation

As noted earlier, it is important that the arrangements for economic regulation do not result in financial disincentives for TNSPs to coordinate in planning the network, and, in particular, do not discourage TNSPs for being proponents for network investment in their region which may address an investment need in other regions.

TNSPs are currently subject to regulation under Chapter 6A of the NER. We note that specific elements of the Chapter 6A arrangements are currently the subject of a rule change proposal submitted by the AER, which is in the process of being considered by the AEMC. The discussion in this section refers to the current provisions of Chapter 6A. We also note that the arrangements applying to the economic regulation of transmission investments in Victoria are somewhat different (as has been discussed earlier in Box 4.1). We discuss the specific situation in Victoria separately below.

In a situation where the 'home' TNSP is the proponent for a transmission option, the approach to economic regulation under the alternative framework would be the same as currently under Chapter 6A. That is, the 'home' TNSP would include the capital expenditure in its expenditure forecasts set out in its revenue proposal to the AER, or would identify the investment as a contingent project; the AER would approve the expenditure forecast, provided that it meets the capital expenditure criteria set out in the NER, or would approve the contingent project; a RIT-T or non-RIT-T assessment would then be undertaken by the TNSP, and the optimal investment option identified;[75] this investment would then be built and rolled into the businesses' Regulatory Asset Base (RAB) at the start of the next regulatory period.

Economic regulation only becomes a potential issue where an 'other region' TNSP may be able to build an investment to meet the need in a different jurisdiction ie, the 'other region' TNSP is the proponent.

It is unlikely to be appropriate to treat these investments as 'unregulated' (ie, remunerated by contract with the 'home' TNSP, outside of the Chapter 6A framework) since:

- these may in some instances be substantial investments, whose use may change over time ie, as they become more integrated into the 'other region' TNSP's network; and
- they may also have significant benefits for the 'other region' TNSP's own network ie, it may defer investment in the 'other regions TNSPs' network.

Therefore, the presumption is that these investments would be treated as regulated investments under Chapter 6A of the NER. We note that this does not preclude treatment of the investment as a non-regulated network option, if appropriate.[76] However, this is unlikely to be common.

There are two potential routes under Chapter 6A for how investments by an 'other region' TNSP could be regulated. We discuss each of these in turn below.

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[75] A RIT-T may have been undertaken prior to the expenditure forecast being submitted to the AER. However in many instances the RIT-T process will be applied during the regulatory period itself.

[76] This is currently permitted under NER 5.6.5D(b).

6.5.1.1. Contingent project route

The first route involves the assets being proposed as contingent projects.[77]

Investment proposed as a contingent project by the 'other region' TNSP

The 'other region' TNSP could include the investment as a contingent project in its revenue proposal, with the trigger being the passing of the RIT-T (conducted by the 'home' TNSP) or a non-RIT-T trigger eg, outcome of an asset condition report.

This situation is most likely to occur if the joint TNSP-TNSP consultation conducted as part of the APR process identifies the likelihood of investment in the other region being a solution to an issue in the TNSP's home region. In order for the project to be proposed as a contingent project, the 'other region' TNSP must demonstrate that the expenditure is required to meet the capital expenditure objectives.[78] There is therefore likely to be a need to revise the wording of the capital expenditure objectives in order to ensure that investments which are being undertaken to meet a need in another jurisdiction are adequately captured. For example, the wording of NER 6A 6.7(a)(2) could be extended to refer to expenditure which is necessary to enable the TNSP to 'comply with all applicable regulatory obligations or requirements associated with the provision of prescribed transmission services, <u>or enable compliance by another TNSP with the regulatory obligations or requirements applicable to that TNSP'</u>.

Once the RIT-T has been applied, assuming that the 'other region' option is the option that satisfies the RIT-T, the 'other region' TNSP would then apply to the AER for approval of the additional revenue associated with the contingent project. Once approved, the TNSP would receive the associated incremental capex and opex revenue during the current regulatory period, via an approved increase in its TUOS charges. The asset would then be rolled into the 'other region' TNSP's RAB at the start of the following regulatory period. Importantly, economic regulation of the 'home' TNSP's is not affected under this approach. However there would need to be consideration of appropriate inter-regional charging arrangements (discussed further below).

Investment proposed as a contingent project by the 'home' TNSP

A second variant of the contingent project route is where the 'home' TNSP proposes the project as a contingent project in its revenue proposal, with the trigger being the passing of the RIT-T (or a non-RIT-T trigger). This situation is likely if the alternative 'other region' option had not yet been identified, or there is substantial uncertainty as to which option is likely to satisfy the RIT-T (or a non-RIT-T assessment).

Once the RIT-T/non-RIT-T assessment has been applied, if it identifies the 'other region' option as being preferred, the 'home' TNSP would apply to the AER for the contingent project allowance. The application would be based on the costs of the 'other region' option.

[77] Grid Australia noted in its submission to the AEMC's First Interim Report that most projects where co-ordination would be beneficial are likely to be sufficiently large to be classified as contingent projects.

[78] NER 6A.6.7(a)).

This approved contingent project amount would increase the 'home' TNSP's TUOS charges for the current regulatory period.

The 'home' TNSP would then pay this amount to the 'other region' TNSP (under contract) for the current regulatory period. The asset would be rolled into the 'other region' TNSP's RAB for the next regulatory period, at which point the contract payments from the 'home' TNSP would cease.[79] We note that this approach is similar in concept to the current arrangements for economic regulation applying between AEMO and SP AusNet in Victoria (detailed above in Box 4.1).

In relation to both of the variants discussed above, we note that in order for a TNSP to propose an investment as a contingent project, the value of the project must exceed the larger of either $10m or 5% of the TNSP's MAR, in the 1st year of the regulatory period. For the majority of TNSPs, 5% of the MAR is larger than $10 million.[80] However, the RIT-T must be applied where the most expensive option considered in the assessment is greater than $5 million.[81] Therefore, not all RIT-T projects could be classified as contingent projects. For projects that fell below the contingent project threshold, the second route for economic regulation (discussed below) would need to be applied.

6.5.1.2. Capital expenditure allowance route

The second route for economic regulation is where the 'home' TNSP proposes the capital expenditure as part of its expenditure forecast included in its revenue proposal to the AER. This would likely occur for smaller projects (eg, under $10m), or if the APR process had not identified the likelihood of investment in another region.

In this case, the 'home' TNSP's capital expenditure allowance would reflect the estimated expenditure that the 'home' TNSP would need to undertake in order to meet the capital expenditure objectives. Its TUOS charges would therefore reflect the costs of the anticipated expenditure.

The 'home' TNSP would later undertake either the RIT-T or non-RIT-T assessment, which may identify investment in another region as the best alternative. The 'home' TNSP would then contract with the 'other region' TNSP for provision of the asset in the current regulatory period, with the contract payments covering the annual costs of the asset (ie, return on and of capital, plus incremental operating costs). In the next regulatory period, the asset will be rolled into the other region's RAB, with contract payments ceasing. Again, this approach is similar in concept to the current arrangements for economic regulation applying between AEMO and SP AusNet in Victoria.

The 'home' TNSP's TUOS charges would remain unaltered under this approach. However part of its revenue would be passed through to the 'other region' TNSP in the contract

79 An alternative to the approach discussed here would be to modify the NER to allow the 'other region' TNSP to apply to the AER for the 'home' TNSP's contingent project allowance. This would avoid the need for contract payments between the 'home' TNSP and the 'other region' TNSP during the regulatory period in which the investment takes place.

80 For example, 5% of Powerlink's MAR is $41m, 5% of TransGrid's MAR is $34m, 5% of SP AusNet's MAR is $23m, 5% of Electranet's MAR is $12m, and 5% of Transend's MAR is $9m.

81 NER 5.6.5C(a)(2).

payment for the asset. The 'home' TNSP has an incentive to coordinate with the 'other region' TNSP (similar to the current adoption of non-network options), since it will benefit from lowering its costs in the current regulatory period.[82] The 'other region' TNSP option would be lower cost than the 'home' TNSP option, and the 'home' TNSP would retain the difference between what it has been allowed and its actual costs for the remainder of current regulatory period.

The NER would need to be modified to ensure that the contract revenue received by the 'other region' TNSP would not be considered as part of its revenue cap. That is, the 'other region' TNSP should be allowed to earn additional revenue from constructing the asset, as this represents an efficient, coordinated outcome for the NEM as a whole.

We note that the capital expenditure rolled forward into the 'other region' TNSPs RAB should not include the amount associated with contract payments from the 'home TNSP' during the current regulatory period (which are akin to capital contributions). We note that in order to give effect to this, changes to the current cost allocation guidelines would be required.

It is possible that the required investment was not foreseen at the time of the regulatory proposal, and so there would be no explicit provision in the 'home' TNSP's capital expenditure allowance for this investment. In this case, the approach described above would still apply. The 'home' TNSP would still contract with the 'other region' TNSP for provision of the asset in the current regulatory period. In the next regulatory period, the asset will be rolled into the other region's RAB, with contract payments ceasing. This situation is no different to the current regulatory arrangements, where the TNSP is still required to build unforeseen investment and bears a cost penalty for any overspend during the current regulatory period. Where the costs of meeting the investment need are lower with an 'other region' option, the TNSP would still have an incentive to contract with the 'other region' TNSP, as it will lower the overall cost penalty it faces during the regulatory period.

6.5.1.3. Application in Victoria

We have considered how the above approach to economic regulation would apply in Victoria, where AEMO is not subject to a revenue determination from the AER (see Box 4.1).

In Victoria, AEMO does not receive a capital expenditure allowance, nor does it propose contingent projects. Therefore, if it is the 'home TNSP', and the preferred option is in another region, then it would simply procure the 'other region' asset under contract, prior to it entering the 'other region' TNSP's RAB. That is, similar to its current approach with SP AusNet.

If Victoria is the 'other region' TNSP then it would work in the same way as described above. The 'home TNSP' would need to arrange for AEMO to procure the investment. AEMO would pay SP AusNet as per the current arrangements (and the asset would eventually enter SP AusNet's RAB). This would occur in both the 'contingent project' and 'expenditure allowance' routes.

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[82] This would only not be the case where the other region TNSP's investment option had higher market benefits than the 'home' TNSP's investment option, but also a higher cost.

6.5.1.4. Inter-regional charging

Under both of the approaches to economic regulation of 'other region' assets, the inter-regional charging arrangements would need to ensure that the appropriate customers pay for the investment. That is, where an investment is being undertaken to meet an investment need (such as a reliability requirement) in a given jurisdiction, it is the customers of that jurisdiction who should pay for that investment, regardless of the region in which the investment is located.

Currently, TUOS charges differ over a particular jurisdiction, reflecting different costs imposed. For example, TUOS charges in north-east NSW may be higher than Sydney, if a substantial investment has recently been built to benefit north-east NSW.

The alternative planning framework may result in an investment being built in Queensland, instead of north-east NSW, to meet the same investment need. Under an inter-regional charging regime that smears costs across the whole of NSW, the costs of that investment would be allocated over the whole of NSW – as opposed to only being allocated to those located in north-east NSW who are benefiting from the investment. Ideally, the inter-regional charging arrangements should allow charges to be targeted at those specific locations in a region which is driving the investment need. This would ensure that the charging regime continues to be cost reflective.

Inter-regional charging is currently under consideration by the AEMC. The AEMC's recent Discussion Paper proposed three options for inter-regional charging. We note that Option 3 (NEM-wide CRNP) would address the concerns described above ie, is cost reflective. It is not clear whether the other two options considered would address these concerns.

6.5.1.5. Summary

It is important in terms of ensuring a nationally coordinated transmission planning outcome that the arrangements for economic regulation do not result in financial disincentives for TNSPs to coordinate in planning the network, and, in particular, do not discourage TNSPs for being proponents for network investment in their region which may address the investment need in other regions.

Under both of the routes for economic regulation described above, the 'other region' TNSP has no financial disincentive to agree to be a proponent for a project in another region, since it can recover its costs either via normal TUOS revenue (ie, via a contingent project trigger) or through a contract payment from the 'home' TNSP for the current period. In the next regulatory period, the asset would get rolled into the 'other region' TNSP's RAB. The 'other region' TNSP also has a reputational incentive to be a proponent, through the transparency of new NER coordination provisions and the RIT-T process.

The 'home' TNSP also has no financial disincentives to have the 'other region' TNSP as a proponent. Indeed, under the second route discussed above, the 'home' TNSP would have a financial incentive to pursue lower cost options in other regions to address the same need, due to the efficiency benefits that can be achieved within the current regulatory period.

The discussion of economic regulation highlights potential advantages associated with aligning the timing of revenue resets for TNSPs. Such alignment would allow the AER to consider the identification of contingent projects and capital expenditure allowances across different TNSP's at the same time, taking into account the potential for cross-regional options. However, the resourcing implications for the AER from aligning reset timing would need to be considered in order to see whether such alignment is feasible.

6.5.2. Reliability standards

Under the current transmission planning framework, network reliability standards are found in a variety of instruments and set by different bodies in each NEM jurisdiction.

In Victoria, transmission planning is undertaken using a probabilistic planning approach in accordance with s 50F of the NEL. Specifically in deciding whether a proposed augmentation to the declared shared network should proceed, AEMO:[83]

> (a) must undertake a cost benefit analysis; and
>
> (b) must apply a probabilistic (as distinct from a deterministic) approach to determining the benefit of an augmentation unless –
>
> > (i) a probabilistic approach will not produce a materially different result; or
> >
> > (ii) it is not reasonably practicable to use a probabilistic approach; or
> >
> > (iii) a probabilistic approach is, for some other reason, in appropriate.

The effective level of network reliability in Victoria is therefore an outcome of this probabilistic planning approach.

In NSW, reliability standards are found in a Network Management Plant that the TNSP is obliged under section 8 of the *Electricity Supply (Safety and Network Management) Regulations 2008* (NSW) to lodge for approval by the NSW Department of Trade and Investment, Regional Infrastructure and Services. The Director-General of the Department has, under to section 13(1) of the Regulations, advised TransGrid to take account of the *Transmission Network Design and Reliability Standard for NSW* when drafting the Network Management Plan.

In Queensland, reliability standards are found in a 'transmission authority' (a form of licence) issued by the Queensland Department of Employment, Economic Development and Innovation to the TNSP pursuant to section 186 of the *Electricity Act 1994* (Qld).

In South Australia, reliability standards are found in the Electricity Transmission Code made by the Essential Services Commission of South Australia pursuant to section 28 of the *Essential Services Commission Act 2002* (SA).

In Tasmania, reliability standards are found in section 5 of the *Electricity Supply Industry (Network Performance Requirements) Regulations 2007* (Tas) administered by the Tasmanian Department of Infrastructure, Energy and Resources.

In Victoria[84], Queensland, South Australia and Tasmania, compliance with the instrument noted above is a condition of the TNSP's licence. Failure to comply with a licence condition may result in civil penalties and, ultimately, suspension or revocation of the licence with the Government or the regulator having the power to take over the licensee's operations (or to

[83] NEL s.50F(2)(b).

[84] These provisions do not appear to apply to AEMO in respect of its Victorian transmission functions.

appoint another person to do so). In New South Wales, TransGrid may be subject to an order of the Director-General if it is not in compliance with any aspect of the Network Management Plan, and failure to comply with an order will attract a civil penalty.

The AEMC has conducted a review of the regulation of reliability standards. It initially published its report, the Transmission Reliability Standards Review, in September 2008, and published an updated report in November 2010. The MCE has recently released a response to this review. [85] The MCE broadly accepted the framework proposed by the AEMC, and has directed the AEMC to undertake further work on the implementation of this.

In terms of the roles and responsibilities in the alternative planning framework set out in this report, the reliability standards are an important part of the regime as these standards provide the basis on which the transmission network must be planned. There are two key issues relevant to this report.

The first is to ensure that there is effective separation between the role of setting the standards and owning the assets which are required to meet those standards, to avoid potential conflict between those roles. As previously discussed, if TNSPs have a role in setting reliability standards they may have incentives to set those standards higher or lower than may be appropriate. Similarly, where the body setting the reliability standard is also the owner of the TNSP (as is the case in both NSW and Queensland), incentives may also be affected. Under the alternative framework, the setting of reliability standards would be undertaken by either a national body (such as the AEMC) or a state-based body (such as a state regulators). In both cases, these bodies are separate to the TNSPs. We note that currently state governments are responsible for determining reliability standards in some jurisdictions.

The second issue relates to the desirability for national consistency in reliability standards, as this will drive greater consistency in transmission network planning and promoting coordination between TNSPs. We note that this is the subject of the AEMC Transmission Reliability Standards Review. We have proposed, however, for current purposes that it would be of benefit for the enhanced NTP role to include an advisory role in relation to reliability standards. This would allow the relevant body determining reliability standards to seek advice from the NTP, which is similar to the role currently undertaken by the NTP for the South Australian jurisdiction, which we understand is performed as part of the additional advisory functions for that jurisdiction under Subdivision 2 of Division 2 of Part 5 of the NEL.

6.5.3. Advisory role to revenue regulation, setting of standards and compliance monitoring

Under the alternative framework, the NTP could play an advisory role in relation to revenue regulation, the setting of reliability standards and compliance monitoring in relation to the application of the RIT-T. In all of these activities the NTP can provide detailed engineering and planning knowledge, which the other institutions may not have, thus enhancing the effectiveness of the overall regime.

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[85] Ministerial Council on Energy, Transmission Reliability Standards Review, Response to the Australian Energy Market Commission Final Report, 16 November 2011.

The NTP is the appropriate body to undertake this role. Importantly, no conflict of interest would be created since the TNSPs are still responsible themselves for the short-term detailed planning and investment decisions.

7. Assessment of the Alternative Framework Against the Principles

In this section we assess the alternative framework for nationally coordinated decision-making, against the principles that we set out in section 3. Importantly, the alternative framework meets all of the principles – see Table 7.1.

Table 7.1 Assessment of the Alternative Framework Against the Principles

	Principle	Is the principle met?
1	Promote investment decision-making on a coordinated basis to maximise net benefit.	✓
2	Allow for both local and a strategic perspective.	✓
3	Allow the use of incentives to promote efficient investment decisions	✓
4	Minimise conflicts of interest	✓
5	Maximise net benefits from reform	✓
6	Allow risk to be allocated to the party best able to manage risk	✓
7	Be clear and transparent in approach	✓
8	Does not create barriers to connection.	✓
COAG	Accountability will remain with TNSPs	✓
	New regime be no slower than the present time	✓
	Must not reduce or adversely impact on the ability for urgent and unforeseen transmission investment to take place	✓

Principle 1 is met since the framework has as a key component NER changes targeted specifically at requiring that TNSPs consult with each other to identify investment options to meet an identified need that may be located in other regions. The requirement for TNSP-TNSP coordination across the APRs, RIT-T and non-RIT-T assessments ensures that investment options in other regions are considered in all stages of planning, and for all investments. The enhanced role for the NTP provides a 'check' on this process, and results in the NTP acting as a central hub in ensuring that coordination occurs.

Importantly, the TNSP itself is responsible for investment decision-making as well as short-term and project specific planning, based on the criteria defined in the NER. This ensures that investment decisions will be made consistent with the outcomes of the coordinated planning process.

Principle 2 is met, since the local perspective is maintained through TNSPs being responsible for producing APRs and undertaking project specific planning. While the NTP may provide demand forecasts as a starting point in this process, these can be modified by the TNSP to reflect particular local knowledge, eg, potential connections or load conditions. The strategic perspective is also maintained through having the NTP produce the NTNDP, providing a high-level strategic plan across the entire NEM.

Importantly, having two different institutions undertake these different planning roles ensures that there is necessary tension and exchange of views as part of the planning process, and that ‘checks’ are provided on each institution.

Principle 3 is met, since the TNSPs as for-profit entities can be incentivised through financial incentives in order to achieve the focus of the alternative planning arrangements. For example, if the TNSP does not consider options in other regions, it will be in breach of NER requirements and so can face a financial penalty. Importantly, the TNSPs do not face any financial disincentives by pursuing coordination under the alternative approach, and stand to gain if they can identify options in other regions which are lower cost than those in their own region.

Conflicts of interests are also reduced, with the exception of in Victoria – ie, ***Principle 4*** is largely met. The investment decision remains with the TNSP for all institutions other than Victoria. This mitigates concerns about any conflicts that may occur where the investment decision maker is also the market operator. There is also appropriate tension in the planning process, and the opportunity for different points of view, through having TNSPs responsible for the detailed short-term plans, and the NTP responsible for the high-level long-term plan.

However, we note that in there is still a conflict of interest between the NTP having the role of NTP and Victorian jurisdictional planner. We discuss this in more detail below in section 8.3.

Principle 5 is met as a consequence of the minimal implementation costs of the proposed framework for most jurisdictions. The alternative framework does not require new institutions to be set up, and instead can be implemented via NER and NEL amendments. However we note that implementation costs may be higher in Victoria, which would require more consideration and we discuss this in section 8.3.

Ideally, adherence to the risk allocation principle (***Principle 6)*** in respect of network planning functions would entail the same entity being responsible for investment decisions that expose them to legal liability risks as well as all upstream planning decisions that affect those operational decisions. However, in our proposed alternative option we have contemplated departures from this 'ideal' structure to the extent desirable to achieve other objectives.

First, our proposed alternative option provides for a scenario where the implementation of an investment decision is made by a TNSP that is different to the TNSP which faces some of the risks associated with that investment. We consider that this is a necessary consequence of increased coordination absent a reform option which involves significant institutional change.

As discussed, we consider the risks to TNSPs resulting from the disjuncture between the risk facing TNSP and the TNSP that makes the investment must be managed by way of contract between the TNSPs. However, as already noted, if this does not occur in practice, thereby impacting on the implementation of other region investments, then it may be necessary to consider imposing further obligations through the NER to facilitate the desired outcomes.

Second, our proposed alternative option retains and enhances the role of the NTP. This provides for the involvement in planning decisions of a different body to that making the ultimate investment decision and implementing the investment. This would be a concern, for example, in a scenario where a TNSP did not support earlier planning conclusions reached by a joint planning body. Although the TNSP would be free to implement the investment decision it considered to be appropriate, the effective overruling of earlier planning activities would call into question the value of those activities. Ideally, the progress from long-term, strategic planning through to short-term detailed planning and the final investment decision should be one in which there is an effective 'funnelling' of planning activities towards the final decision. However, given the nature of the NTP's role, and in particular its focus on long-term strategic planning, we consider that any risks that the NTP's involvement in planning activities will turn out to be redundant is low, and are outweighed by the enhancements proposed to the NTP's role and the value of having a different perspective applied to the first-stage of planning activities.

This proposed approach is clear and transparent in approach – ***Principle 7*** is met. The NER changes ensure that this coordination occurs in a clear and transparent manner, with this occurring in a number of publicly available documents. This will readily ensure assessment of whether increased coordination is being achieved. The enhanced role for the NTP improves transparency of information to TNSPs, the market and market institutions.

The alternative framework does not create barriers for connection (***Principle 8***). Connection arrangements are the same as in the current planning framework, and so no additional barriers are created.

The COAG principles are also met. TNSPs are still accountable for jurisdictional investment, operation and performance since they undertake the investment decision, as well as maintaining, operating, owning and having liability for the asset. Moreover, since the alternative framework does not significantly change the current framework it will not be slower than the present time taken to gain regulatory approval for transmission investments. While the NTP has an enhanced role in commenting on aspects of the TNSPs' APRs and RIT-T documentation, the timeframes within which these documents must be produced are maintained.

Lastly, it will not reduce or adversely impact on the ability for urgent and unforseen investment to take place. Urgent and unforseen investment will be dealt in the same manner as currently (ie, TNSPs must simply construct this where necessary). The alternative framework does not impinge on this ability. We note that the timeliness of this investment means that it is unlikely that coordination will occur. However, these investments would not currently be subject to the full RIT-T process, and so less consideration is given to potential options in the current framework.

8. Implementation of Alternative Framework

This section describes in general terms the main changes that would be required to the NEL and the NER to implement the proposed alternative framework. It also considers changes that may be specifically required in Victoria and South Australia, as the two jurisdictions which currently operate under a variation of the planning framework established under the NER and NER.

At this stage we have not considered specific drafting or identified all changes that may be required for the implementation of the proposed alternative framework.

8.1. NEL Changes

Subject to the discussion in sections 8.3 and 8.4 in relation to the Victorian and South Australian jurisdictions, the alternative planning framework proposed in this report can be mainly implemented through the NER and does not require significant changes to the NEL.

The first change which may be desirable would be to expand the functions of the NTP as described in section 49(2) of the NEL.

The additional functions to be conferred on the NTP would be covered by the catch all provision in section 49(2)(e). However, given the significance of these new functions, it may be preferable to add a specific paragraph reflecting the change to the NTP's role, for example:

> to assist [transmission network service providers] to undertake consistent and coordinated transmission planning by providing planning data as required by the Rules and facilitating coordination between [transmission network service providers].

The second change relates to the proposed advisory role for the NTP in relation to reliability standards. Under the existing provisions of the NEL, it is already possible for a jurisdiction to declare that subdivision 2 of Division 2 of Part 5 of the NEL applies in that jurisdiction, and to seek AEMO's advice in accordance with that subdivision. However, we suggest that it would be preferable for equivalent provisions to be included as NTP functions that apply to all jurisdictions, without the need for the jurisdiction to make such a declaration.[86] While this would not compel jurisdictions to seek NTP advice on reliability standards, including this role as an NTP function of general application may encourage jurisdictions to do so.

8.2. NER Changes

8.2.1. Planning

8.2.1.1. Long-term strategic planning

Long term strategic planning is currently undertaken through the preparation of the NTNDP by the NTP (clause 5.6A).

The proposed enhanced TNSP input into the NTNDP would be effected through amendment to this provision, requiring the establishment of a TNSP working group and setting out the

[86] For example, this could be done by repealing section 50(1) and section 50B, and inserting a provision similar to section 50B in Division 1 of Part 5 of the NEL.

process for that working group to review and provide comments on the NTP during its development.

8.2.1.2. Short-term strategic planning

Short term strategic planning is currently undertaken through the preparation by TNSPs of the APRs, as required by clause 5.6.2A. Elements of clauses 5.6.1, 5.6.2 and 5.6.3 are also relevant to this process.

Changes to these provisions would be required as a result of the proposals for ensuring coordination between TNSPs and the enhanced NTP role.

These changes would include the following.

Demand forecasts

The NTP would be required to provide demand forecasts to each TNSP as part of the annual planning process (this could be addressed in clause 5.6.3, noting that it applies to a number of different processes). These are in the nature of 'top down' forecasts, and would be in addition to the 'bottom up' information that is currently required to be provided by Registered Participants under clause 5.6.1.

TNSPs would not be compelled to use the NTP forecasts, but would be required to be transparent in their APRs in relation to departures from the NTP forecasts that they consider are required to accurately reflect local conditions (clause 5.6.2A).

As noted above we understand that, as a matter of jurisdictional practice, TNSPs in some jurisdictions are required to undertake 'top down' demand forecasts under local instruments, such as a Ministerial order. To achieve a consistent approach, it would be necessary for jurisdictions to withdraw any such requirements to allow the TNSPs to use the NTP demand forecasts as contemplated above.

Coordination between TNSPs

TNSPs would be required to consider whether an investment need could be met by an option in another region, and to consult with TNSPs in those other regions in preparing their APRs.

Clause 5.6.2A would be amended to require TNSPs to include in their APRs, for each investment need (clause 5.6.2A):

- whether an option in another jurisdiction may meet an investment need or, if not, the reasons why not; and
- the consultation that it has undertaken with TNSPs in neighbouring regions.

In considering whether investment needs may be met by options in other regions, TNSPs would be required to have regard to guidelines published by the NTP (clause 5.6.2A would impose this obligation on the TNSP and clause 5.6.3 would require the NTP to prepare and publish such guidelines).

Review by NTP

TNSPs would be required to submit their APRs to the NTP for review (clause 5.6.2A).

This review would be limited to:

- the use of the demand forecasts as provided by the NTP; and

- the coordination between TNSPs for investment needs that may be met by an option in another region.

The NTP would be required to provide comments on these aspects of the APRs. In respect of the coordination aspects, the NTP would be able to comment both on:

- investments where the TNSP has identified an option in another region; and
- investments where the TNSP has not identified an option in another region, but the NTP considers there may be such an option worth investigating.

The TNSP would not be compelled to action and incorporate the NTP's comments. However, if it did not agree with the NTP's comments in relation to demand forecasts or coordination, it would be required to explain the reasons for not adopting the NTP's suggestions in its APR (clause 5.6.2A).

8.2.2. Project specific planning

8.2.2.1. RIT-T investments

The requirement for and process for undertaking the RIT-T is currently set out in clauses 5.6.5B, 5.6.5D, 5.6.5E, 5.6.6, 5.6.6A and 5.6.6AA.

As above, changes to these provisions would be required as a result of the proposals for ensuring coordination between NSPs and the enhanced NTP role.

These changes would include the following.

Demand forecasts and scenarios

The demand forecasts prepared by the NTP for the APR process and the scenarios developed by the NTP for the purposes of the NTNDP (clause 5.6A.2(c)(3)) would both be relevant for the purposes of the RIT-T.

As for the APRs, the TNSPs would be required to be transparent in their RIT-T documents in relation to the way in which they have updated and departed from the most recent demand forecasts prepared by the NTP.

TNSPs would also be obliged to use any relevant scenarios developed by the NTP for the purposes of the NTNDP and, again, be transparent where they have made variations to those scenarios.

Each of these matters would be addressed in the contents requirements for PSCRs in clause 5.6.6.

Coordination between TNSPs

TNSPs would be required to consider whether an investment need could be met by an option in another region, and to consult with TNSPs in those regions in preparing their RIT-Ts. Clause 5.6.5D would be amended to specifically recognise investments in other regions as a *credible option.*

Clause 5.6.6 would be amended to specifically require TNSPs to set out in its PSCR and PADR, for each investment need:

- whether an option in another region may meet that need or, if not, the reasons why not; and

- the consultation it has undertaken with TNSPs in neighbouring regions.

In considering whether investment needs may be met by options in other regions, TNSPs would be required to have regard to guidelines published by the NTP under clause 5.6.3 (referred to section 6.1).

Review by NTP

TNSPs would be specifically required to submit their PSCRs to the NTP for review prior to publication of the PSCR (clause 5.6.6).

The review would be limited to the coordination aspects of the PSCR.

The NTP would be required to provide comments on this aspect of the RIT-T. As for the APR, the NTP would be able to comment on an identified option or propose an option for investigation.

The TNSP would not be compelled to action and incorporate the NTP's comments. However, if it did not agree with the NTP's comments it would be required to explain the reasons for not adopting the NTP's suggestions in the PADR.

Consistent with current clause 5.6.6(l) an option for investment in another region would only be able to be included in the PADR if the TNSP in the other region (or, if it is contestable, another person) has agreed to be the proponent for that investment.

The NTP would also be entitled to make submissions on the PADR as part of the existing consultation process.

8.2.2.2. Non-RIT-T investments

Clause 5.6.5C(a) currently provides that non RIT-T investments must be planned and developed at least cost over the use of the asset.

We propose that a specific reference to giving consideration to investment options in other regions and to consulting with TNSPs in those regions should also be included, but suggest this would be more appropriate as part of the capital expenditure factors in clause 6A.6.7(e) to be considered by the AER in making a revenue determination.

8.2.3. Implementation of the investment

As discussed earlier, it is envisaged that implementation of the investment by an 'other region' TNSP would be undertaken on a contractual basis. However, it may be necessary for this to be reconsidered if it is not occurring in practice.

8.2.4. Economic regulation

Some changes to the NER may be required from an economic regulation perspective.

In particular, an amendment to the capital expenditure objectives in clause 6A.6.7 may be required in order for an 'other TNSP' to be able to recover revenue for constructing an asset that is required to meet the regulatory obligations of the 'home TNSP'. Similar changes may also be appropriate in clause 6A.6.6 in relation to the operating expenditure objectives.

An additional carve out would also be required from the prohibition on earning in excess of the maximum allowed revenue for prescribed transmission services (clause 6A.3). This would allow the "other region" TNSP to earn additional revenue under the contract with the "home" TNSP, until the asset is able to be rolled into the RAB of the "other region" TNSP.

As previously noted, these contractual payments should be treated as capital contributions and netted off the amount that is rolled into the RAB. We propose this would be addressed in the cost allocation guidelines made by the AER under clause 6A.19.3.

We also note that changes to the NER would be required in order to implement inter-regional TUOS charging arrangements. However, we have not addressed these changes here as this is being considered under a separate process.

8.2.5. Other issues

The other elements of the enhanced NTP role include:

- an advisory role to the AER in relation to economic regulation (note that this is already covered by clauses 6A.6.6(e);
- an advisory role to the AER on monitoring compliance with the RIT-T (this could be addressed in clause 5.6.3) and on disputes in relation to the application of the RIT-T under clause 5.6.6A.

8.3. Issues in relation to Victoria

As discussed earlier in this report, one of the benefits of the proposed alternative framework and, in particular, the enhanced NTP role is that it provides a degree of oversight and tension in the planning process. We consider that the continued separation of roles between the NTP and TNSPs as proposed will lead to better planning outcomes.

In Victoria, the NTP and TNSP responsible for planning are the same entity. Accordingly, this particular benefit is not able to be delivered in the Victorian jurisdiction.

There are a number of institutional reforms that could be undertaken in order to address this issue, each of which would require the support of the Victorian Government.

8.3.1. Ringfencing

The first option would be for that part of AEMO that undertakes some or all of the Victorian declared network functions[87] to be ringfenced within AEMO.

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[87] AEMO's declared network functions are set out in section 50C(1) of the NEL as follows:

(a) to plan, authorise, contract for, and direct, augmentation of the declared shared network;

(b) to provide information about the planning processes for augmentation of the declared shared network;

(c) to provide information and other services to facilitate decisions for investment and the use of resources in the adoptive jurisdiction's electricity industry;

(d) to provide shared transmission services by means of, or in connection with, the declared shared network;

(e) any other functions, related to the declared transmission system or electricity network services provided by means of or in connection with the declared transmission system, conferred on it under this Law or the Rules;

(f) any other functions, related to the declared transmission system or electricity network services provided by means of or in connection with the declared transmission system, conferred on it under a law of the adoptive jurisdiction.

This would mean that the AEMO personnel performing the NTP function would be different to the AEMO personnel performing the declared network function. This would provide, to some degree, the same benefits as would be achieved for the other jurisdictions.

The disadvantage of this approach is that it results in duplication within AEMO, as AEMO could require two separate teams with the requisite planning expertise. However, we understand that the costs of AEMO performing its declared network functions are borne by Victorian consumers and AEMO's costs of performing the NTP role are recovered from Registered Participants generally. The duplication in roles would in effect be the same as currently exists for other jurisdictions where there is a team within each TNSP which has responsibility for the functions which, for Victoria, are undertaken by AEMO as declared network functions.

In addition, ringfencing solutions are typically considered to be less effective that actual structural separation. This is both because of potential on-going perceptions that the activities are not fully separated, given that they are still conducted by the same body, as well as the continuing single management structure that would sit above both functions.

This option could be implemented through Division 2 of Part 5 of the NEL, pursuant to which these functions are created.

8.3.2. New Victorian planning entity

An option involving more significant change that would provide for separation between the NTP and TNSP planning roles for Victoria would be for the relevant functions to be carried out by a body other than AEMO. For example, the functions could be conferred on a new or existing Victorian statutory corporation.

In considering this approach, an issue arises in relation to AEMO's declared system functions under the NGL.[88] AEMO operates the Victorian wholesale gas market and undertakes gas transmission functions under similar legislative arrangements in the NGL to those which establish the declared network functions in the NEL. However, we note that the actual functions are undertaken by AEMO in this context are different. For example, in relation to the gas market, AEMO does not have responsibility for making investment decisions as it does in electricity, but only to monitor and review the capacity of the declared transmission system.

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[88] AEMO's declared system functions are set out in section 91BA of the NGL as follows:

(a) to determine security standards for the declared transmission system;

(b) to control the operation and security of the declared transmission system;

(c) to monitor and review the capacity of the declared transmission system and the trends in demand for the injection of gas into, and the withdrawal of gas from, that system;

(d) to provide information and other services to facilitate decisions for economically efficient investment in markets for natural gas;

(e) to coordinate the interaction of producers, storage providers and service providers for ensuring a safe, secure, reliable and efficient declared transmission system;

(f) to operate and administer the declared wholesale gas market;

(g) to make, amend or revoke Procedures governing the operation and administration of the declared wholesale gas market.

If some or all of the declared network functions for electricity were to be transferred to a new body, then consideration would need to be given as to whether any of the equivalent declared system functions for gas should also be transferred. This would depend on whether greater synergies exist in the relevant functions as between the Victorian electricity and gas industries on the one hand, or between the various declared system functions on the other.

A further issue arises in relation to the cost effectiveness of this proposal, and whether it would be more or less costly than the ringfencing option described above. This is likely to depend in part on whether the functions can sensibly be given to an existing body (which would make this option more cost effective), or whether a new body would need to be established just for this purpose. In considering the cost effectiveness of this option, the potential for it to deliver greater benefits than the ringfencing option through the achievement of more effective separation should also be taken into account.

Changes to both the NEL and the NER (and possibly the NGL and NGR) would be required to implement this option.

8.3.3. Transfer TNSP planning function to SP AusNet

A final option, which is again more significant, would be for the declared network functions to be given to SP AusNet. This would place SP AusNet in the same position as the other TNSPs in the NEM, and allow for separation of the NTP from jurisdictional transmission planning activities in Victoria.

In addition to the considerations noted above for the creation of a new planning entity, this approach would also need to be agreed with SP AusNet, otherwise sovereign risk issues may arise (as noted earlier in relation to the proposal for a TNSP joint venture).

We note that SP AusNet currently has a role as distribution planner, through its distribution business.[89]

8.4. Issues in relation to South Australia

As discussed above, we propose that provisions similar to subdivision 2 of Division 2 of Part 5 of the NEL should have general application, rather than being limited to adoptive jurisdictions, in order to encourage jurisdictions to seek NTP advice on reliability standards.

If this approach is adopted then these provisions would no longer apply only in respect of adoptive jurisdictions and would be replaced by equivalent provisions of general application.

8.5. Interaction with Generator Network Access Packages

The AEMC's First Interim Report also proposed five preliminary packages of policy reform, focussing on different levels of generator network access.

We understand that the AEMC is now considering two potential packages in further detail, specifically:

1. a Non-firm Access regime;[90] and

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[89] See SP AusNet, Distribution System Planning Report 2012-2016, 2011.

2. an Optional Firm Access regime.[91]

These packages would each interact with the transmission planning framework. We have therefore considered the potential implications of the adoption of either package on the alternative transmission planning framework set out in this report.

Under Option 1 (ie, a Non-firm Access Regime) generators would not have any firm access rights. That is, generators would have a right to connect to the transmission network, but no rights to dispatch output across the network. Consequently, when a generator is dispatched, and there are no constraints in the network, it would export its output and so earn revenue. However, if it is constrained in how much it can export, and is not fully dispatched, it will face lost opportunities for revenue.

Under Option 2 (ie, an Optional Firm Access regime), generators would be able to choose a level of firm access to the regional reference node and would pay the TNSP for this right.[92] If there is a constraint on the network, and a 'firm' generator is not able to be dispatched, then it would be eligible for financial compensation from the TNSP. 'Non-firm' generators would still face lost opportunities to earn revenue if they are constrained ie, they would receive no compensation.

In an Optional Firm Access model, TNSPs would be required to plan to a standard to allow for firm generator access. That is, to plan to a standard that ensured, under defined operating conditions (and ignoring non-firm generation), all firm generation would be able to access the regional reference node. This requirement would be reflected in the NER. TNSPs would also still have to plan to meet the existing reliability standards for load. The RIT-T would be adapted to reflect these new planning standards.

We next consider how our alternative transmission planning framework would interact with each of these proposed models.

8.5.1. Alternative Planning Framework under a Non-firm Access Regime

Under Option 1 (ie, a Non-firm Access regime), the alternative transmission planning framework would work as set out in sections 5 and 6 of this report. This option is substantially based on the arrangements that exist in practice in the NEM today.[93] Under this option the NER would simply be modified to clarify that the NEM operates as an open access market, and NER clause 5.4A would be removed. Since there are no associated changes that influence network planning, there are no implications for the alternative transmission planning framework.

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[90] This can be considered equivalent to 'Package 1: an open access regime' as set out in the First Interim Report. See: AEMC, First Interim Report Transmission Frameworks Review, 17 November 2011, pp.56-64.

[91] This can be considered a hybrid between 'Package 2: Open access with congestion pricing' and 'Package 4: Regional optional firm access model' as set out in the First Interim Report. See AEMC, First Interim Report Transmission Frameworks Review, 17 November 2011, pp.65-74; and 92-105.

[92] Generators would be able to choose a quantity of access for which they are firm, ranging from zero to their full generating capacity. However, for ease of discussion here we only consider 'firm' (ie, those that have paid for firm access for their full capacity) or 'non-firm' (ie, those who have not paid for firm access).

[93] Indeed, this was recognised in the First Interim Report. While some generators consider that the presence of NER clause 5.4A means that they can negotiate with TNSPs to obtain firm access to the regional reference node, the AEMC considers that this cannot work in practice because the scheme is not mandatory, and all generators have open access to the network. See: AEMC, First Interim Report Transmission Frameworks Review, 17 November 2011, p.57.

8.5.2. Alternative Planning Framework under an Optional Firm Access Regime

If an Optional Firm Access regime (ie, Option 2) is pursued then there are two corresponding implications for the alternative transmission planning framework.

The first is that when TNSPs invest to meet the required generation planning standard, the need may be potentially be addressed by an alternative investment option located in another region (ie, the same considerations are needed as set out above for those reliability investments).

This is already reflected in the alternative transmission planning framework. The RIT-T would need to be applied by the TNSP (with the identified need being to meet a required generation planning standard), and the alternative framework requires options in other regions to be considered as part of the RIT-T application.

The second implication arises from the possibility that, for a TNSP in a particular region to provide firm access to a generator, it may require upgrades to the network in another jurisdiction. In this situation, the network in the other region is *integral* to ensuring that the generator has firm access ie, firm access cannot be provided unless both TNSP networks are upgraded.

For example, a generator located near the Queensland border may pay Powerlink for firm access to the transmission network. However, provision of this firm access may in practice require part of TransGrid's network in NSW to be upgraded, given the pattern of power flows on the interconnected network. This would therefore involve investment by both Powerlink and TransGrid, in order for Powerlink to guarantee firm access to the generator. The alternative planning framework requires the 'home' TNSP to consult with the 'other region' TNSP in the identification and, ultimately, the development of the option that provides the greatest net market benefit. This would occur if the option either involved an investment in the 'other region' TNSP's network or for investments that involve assets in more than one region. However, once the preferred option has been identified, TNSPs still need to agree to build the investment. Continuing on the above example, this would require *both* Powerlink and TransGrid to be proponents for the investment.

We note that there is no financial disincentive for the 'other region' TNSP to agree to be a proponent, since they would be compensated through the framework for economic regulation (as set out in section 6.5.1). However, the alternative planning framework relies on a degree of moral suasion being applied to provide an incentive for the 'other region' TNSP to be a proponent.

There may be concerns under an Optional Firm Access model that moral suasion will not be sufficient to convince the 'other region' TNSP to become a proponent for investments in its region which provide firm access to a generator located in a different region. This concern may be greater than in the case of the Non-firm Access approach, since for reliability-driven investments there will always be an investment option located in the 'home' TNSP's region which could proceed if the 'other region' TNSP refused to be a proponent. However, in the case of generator planning standards this may not be the case.

In addition, we note that if under the Optional Firm Access model Powerlink (in this example) were to be liable to pay financial compensation to the generator if firm access is not available, then this liability would need to be imposed on TransGrid through contractual means, in respect of the assets under TransGrid's control. As discussed previously, TNSPs may be reluctant to voluntarily accept additional liability of this nature.

If there were such concerns, further thought could be given to imposing an obligation in the NER on the 'other region' TNSP to be a proponent, in cases where investment in the other region forms part of the investment option which satisfies the RIT-T. Finally, it may also be relevant to consider such an obligation if there are concerns that the negotiation between TNSPs to allow firm access to generators may prolong generator connection times.

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