Analysis of Scoping Paper for Implementation of National Transmission Planner
Version 1.1

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This submission was prepared by the EUAA with assistance from McLennan Magasanik Associates Pty Ltd (MMA). Funding assistance was provided by the National Electricity Consumers' Advocacy Panel

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EXECUTIVE SUMMARY

The Energy Users Association of Australia (EUAA) supports the development of a National Transmission Planning function to coordinate investment in and the development of long-term planning of the gas and electricity transmission systems. The development of network plans from energy supply and demand scenarios is a complex task that requires coordination of inputs from across the whole electricity value chain from energy sources to customers.

The EUAA supports the recommendations of the Energy Reform Implementation Group (ERIG) and the Council of Australian Government's (COAG's) response to the ERIG report in respect of the establishment of a National Transmission Planner (NTP). The role of the NTP must be distinct, and separated from the TNSPs to avoid duplication of effort and the risk of inefficiency arising from market participants working at cross-purposes. The NTP's planning focus should:

- Assess the impact of Government energy policies;
- Monitor technology trends affecting transmission development;
- Monitor the development and competitiveness of fuel sources and new generation sites;
- In conjunction with stakeholders, identify suitable supply scenarios that represent the possible range of futures that may need to be addressed including potential changes to Government policies to address emerging issues that may not have a current focus;
- Identify the network development options which have already been established by TNSPs and their stated purposes and economic benefits, and the way that these developments fit with, and can be best utilized in the national planning process;
- Coordinate the use of technical and economic analysis to identify potential augmentations and the timing of those augmentations that would serve the market needs at least cost for the chosen scenarios;
- Create standard procedures and documentation processes for the economic and technical evaluation of gas and electricity transmission development projects;
- Facilitate communication among stakeholders in the electricity market supply chain from fuel suppliers to customers.

It is not reasonable to expect Transmission Network Service Providers (TNSPs) to play their full part in this process without some participation in formulating scenarios; options and methodologies that would facilitate coordinated evaluation.

A more transparent process that provides useful information about the economic value drivers for transmission development would also assist market participants to bring forward supply and demand based projects that could be used to defer network development or enhance the economic value of those developments.

Some proposals that are presented by the EUAA in this Response towards more effective planning processes include:

- Requiring the NTP to coordinate a long term planning process that develops energy supply scenarios having regard to current and prospective government energy policies. These scenarios would then be used to identify the transmission network elements that would be required to minimise the delivered cost of electricity or gas for the alternative scenarios, preferably with regard to the uncertainty between and within those scenarios.

- Requiring the NTP to describe and maintain a Planning Boundary within which transmission assets are likely to create significant market impediments or benefits if they were to be removed or augmented. The Planning Boundary would assist in maintaining focus on the main game of maximising the value of the whole NEM transmission system. The Planning Boundary would be varied periodically and as necessary to ensure that transmission assets and areas that contribute broader market benefits are included. The NTP should also retain the flexibility to modify the Planning Boundary as required to take into account radical new scenarios.

- As part of the revision of the Regulatory Test, requiring the NTP to develop standard procedures for screening options for the applicability of market benefits in their economic evaluation. This would help to focus analytical resources where significant market benefits are to be evaluated.

- Creating a standardised method for conducting an initial market benefit screening on all significant transmission projects to identify if market benefits would offset more than 10% to 20% of the present value costs of a transmission project. If so, the maximising of market benefits would need to become an objective in the Regulatory Test approval process, rather than merely focusing on reliability criteria.

- Defining Timing Functions which describe the optimal timing of a proposed transmission asset in terms of measurable energy market variables, based on economic evaluations completed to date. Such Functions would facilitate market participants finding more economic alternatives that could be used to defer or avoid an otherwise proposed project.

DEFINITIONS

Some new concepts are developed in this paper. To assist the reader, a list of definitions and explanations is provided in Table 0-1. Other terms are added that are defined by COAG and MCE.

Table 0-1 Terms and definitions

Term	Definition	Application
National Gas Market (NGM)	Transmission infrastructure that connects gas transmission pipelines across jurisdictional boundaries	There is a need to draw in gas planning functions with electricity planning functions as part of any role of the NTP, and a consequent need to develop definitions that facilitate NTP-based concepts and processes.
National Transmission Planner (NTP)	A role undertaken that conducts the national and long-term aspects of the planning of the transmission system in the National Electricity Market and the National Gas Market.	The role may be incorporated within AEMO or may be conducted by a separate entity responsible to the Ministerial Council on Energy through the Australian Energy Market Commission.
National Transmission Network Development Plan (NTPDP)	A document produced annually that forecasts transmission development requirements for the next 10 years.	Provided as a guide to TNSPs and market participants to facilitate the coordination of energy markets and the development of the transmission system to minimise the cost of delivered electricity.
National project	A transmission project when the market benefits are expected to be at least 10% of its costs over its economic life	Such a project may not be sufficiently justified by its local reliability benefits and therefore the TNSPs revenue cap ought to be based upon when the project is delivered.

Term	Definition	Application
AEMO	Australian Energy Markets Operator	An organization to replace the National Electricity Market Management Company (NEMMCO) and to assume the role of operating the NGM and NEM.
Planning Boundary	A geographic border specified around the transmission system in which any changes to assets are highly likely to have market benefits. Assets outside the Planning Boundary are unlikely to have market benefits because the do not have access to low cost energy resources.	The National Transmission Planner would focus primarily on the management and development of network assets within the Planning Boundary.
Planning Boundary Review	A process that investigates whether there has been a change in technology or the availability of low cost energy resources that would justify the change in the Planning Boundary.	The National Transmission Planner would review the Planning Boundary periodically or when circumstances affecting the definition of the Boundary have changed materially.
Timing Function	A mathematical function of market factors such as peak demand, embedded generation capacity and seasonal availability, inter-regional power flows and price differences that define the optimal timing of a planned asset based on technical and economic analyses performed to date. Such a function would be defined for major assets where market benefits are significant or where they could be increased or reduced depending on investments and operations in the energy and ancillary services markets.	

1 INTRODUCTION

In its communiqué of 13 April 2007, The Council of Australian Governments (COAG) announced its decision to establish an enhanced planning process for the national electricity transmission network to promote more strategic and co-ordinated development of the transmission network and to assist in optimising investment between transmission and generation across the power system. At the Council of Australian Government's (COAG's) request, the Ministerial Council on Energy (MCE) has directed the Australian Energy Market Commission (AEMC) to conduct a review into development of a detailed implementation plan for that enhanced national transmission planning function.

As part of this review the establishment of a National Transmission Planner (NTP) is proposed to take a nationally focused role in developing long term plans for the transmission system, and the interaction of the gas transmission system with the electricity transmission system. A review of the prospective role of the NTP is underway which involves three main tasks as listed in the Scoping Paper published by The AEMC in August 2007. These tasks include:

- the development of an implementation plan for the national transmission planning function, including arrangements for the preparation of a 10 year National Transmission Network Development Plan (NTNDP) to be updated annually;
- consideration of the case for simultaneous review and determination of Transmission Network Service Provider (TNSP) revenue caps, in place of the current sequential reviews; and
- a revised network planning and consultation process, to replace the current 'Regulatory Test' with an assessment process that amalgamates the reliability and market benefits criteria of the current Test.

McLennan Magasanik Associates (MMA) has been engaged by the Energy Users Association (EUAA) with the financial support of the Advocacy Panel to review the Scoping Paper and to respond to the questions raised in that paper.
This report reviews the processes that might be fulfilled by a National Transmission Planner having regard to the existing responsibilities of TNSPs in the National Electricity Market (NEM). This report provides a high-level process map that describes the activities related to transmission planning in the NEM, and the way that an NTP might assume these responsibilities

2 THE PLANNING PROCESS

2.1 Transmission role

The transmission planning process must consider a wide range of factors in the NEM because transmission provides an integrating role in:

- opening up new generation centres based on newly developed fuel resources
- ensuring efficient generation development and operation
- power delivery to major load centres
- balancing supply and demand across the NEM regions
- facilitating competition between generators in different locations
- maximising utilisation of subordinate distribution networks
- the management of varying renewable energy resources (hydro and wind)
- provision of reliable and secure supply to major load centres, and
- evaluating the alternatives and facilitating competition between gas transportation and electricity transmission in the gas fired power generation sector of the energy market.

2.2 State based planning

Traditionally these planning processes for the NEM have primarily operated at state level in the context of state based energy policies:

- Powerlink for Queensland
- TransGrid for NSW, Snowy region and ACT
- VENCorp for Victoria
- ESIPC for South Australia.

In the distant past this has led to sub-optimal network developments, the most obvious being the development of a connection to Broken Hill on the north side of the Murray River when a reinforcement though Victoria would have offered substantially lower cost. In more recent times, the processes that TransGrid followed in seeking regulatory approval for the South Australian Network Interconnector (SANI), at the same time that Murraylink was being developed and committed and Playford Power Station being refurbished demonstrated a failure of strategic planning processes for a project crossing State borders.

On the other hand, there have been some great successes. The establishment of the 500/275kV interconnection between Victoria and South Australia after completion of the 500kV line to Portland was planned in a sound manner including evaluation of 500kV and 275kV options into South Australia. In the early years this link created capacity savings as expected together with energy trading benefits well in excess of the planned levels. Similarly, low cost augmentation of the Snowy to Melbourne transmission link without construction of new power lines has facilitated competition in peaking power and deferred the need for new generating capacity in Victoria and South Australia.

2.3 Need for a long term NEM and NGM planning focus

Now that the NEM is becoming more dynamic and the influence of state boundaries is diminishing, there is need for a high level co-ordination of the development of the network as a whole to ensure that energy trading opportunities are maximised consistent with the cost of augmenting and operating transmission assets, and to ensure that the development of the NEM takes into account, where possible, synergies with the development of the NGM that can be exploited. The particular drivers for this transformation of the role of the transmission system currently arise from a number of changing factors:

- New fuel sources are being developed in south and central Queensland for supply to both NSW and Queensland regions. This results in an increased focus on cross-border energy transfer and trade-off in the use of coal and gas between adjacent NEM regions.

- The increased focus on inefficiency in investment has reduced the spare capacity available in the electricity transmission system and there is an increasing incidence of constraints arising throughout the transmission system. As the recent paper on transmission performance standards has stated, these constraints occur in various times and places that cannot always be anticipated. This has happened in part due to the drought and due to the changing role of gas-fired peaking plants that are operating to meet the peak demand in more than one region. For example, peaking plants in Victoria have been supplying peak demand in NSW because of the limited energy available from Snowy. The electricity transmission system was never specifically designed for that operating mode occurring so frequently or consistently.

- Energy production across the NEM has responded, and in future could be expected to be strongly influenced by competitive forces and the emerging trends in emission abatement. These emerging trends and responses to competitive pressures are slowly changing the role of the transmission system from point to point power transfer and regional connection to the connection of centralised and distributed energy sources, with an increasing proportion of volatile renewable energy sources from wind and solar sources.

- The possibility of large base load power plants using nuclear technology or advanced coal plants with carbon sequestration post 2020 may increase the need for long distance power transmission at very high voltages. Nuclear is most efficient in large centralised facilities where there is access to sea water cooling, subject to acceptance by local communities and sufficient exit capacity on the transmission system. Whilst it may be technically feasible to distribute nuclear power plants around the grid near major coastal load centres, community concerns may limit the available locational options. Furthermore, the economic size of nuclear units is in the range 800 to 1300 MW and such units (or other similarly-sized generation) could not be placed in South Australia or at the extremities of the grid such as North Queensland due to stability constraints. Therefore, long-term network planning may need to consider an increased role for long distance transmission for the following resources:

    - Wind power out of the southern regions of the NEM
    - Nuclear power out of the central regions of the NEM
    - Coal fired plants with carbon sequestration in Latrobe Valley and Queensland
    - Geothermal power out of Central Australia into the major load centres
    - Gas fired power out of the vast coal seams in NSW and Queensland.

2.4 Elements of long term planning

The elements of long term planning that should be the focus of the NTP are represented in Figure 2-1 and represent one approach to the development of the NTP's functions. The shaded area covers the primary activities that would be managed by the NTP. The boxes with the thicker borders represent the primary inputs to the NTP's activities. Consultation processes would be a key component of the coordination processes to ensure that relevant information is able to be offered by all stakeholders. The issues are discussed below under the schema of inputs, analyses and outputs.

2.4.1 Inputs

The key inputs to the long-term transmission planning process are analysed in Figure 2-1 Structure of the Long Term Transmission Planning Process

Table 2-1. They include:

- The existing state of the network assets including remaining life and expected technical and economic performance;
- Economic growth and associated forecasts of electricity demand and its spatial distribution;
- Government energy policies that determine which kinds of energy resources are favoured, promoted, or quarantined from exploitation;
- The location and state of development of current and prospective fuel resources and associated generation options;
- The development of the gas pipeline networks and how they influence the possible location of gas fired generation;
- The capacity of existing easements and possible future allowable routes for transmission lines; and
- Development options and perspectives informed by TNSP, local and regional plans.

The primary role of long term planning which is not being undertaken in a fully co-ordinated manner across the NEM and the NGM is the consideration of energy supply scenarios and how they may influence future transmission needs. Some aspects of transmission planning need to look at least 30 years ahead to gain sufficient economic perspective.

Figure 2.1 is a representation of the way in which the EUAA considers the NTP may integrate and undertake its functions within the existing schema of functions of existing stakeholders, to achieve a stated purpose of effective long term energy market planning.
Table 2.1 documents the inputs and outputs that could be expected to form the basis of the assessment and planning process associated with the national transmission planning function.

Figure 2-1 Structure of the Long Term Transmission Planning Process

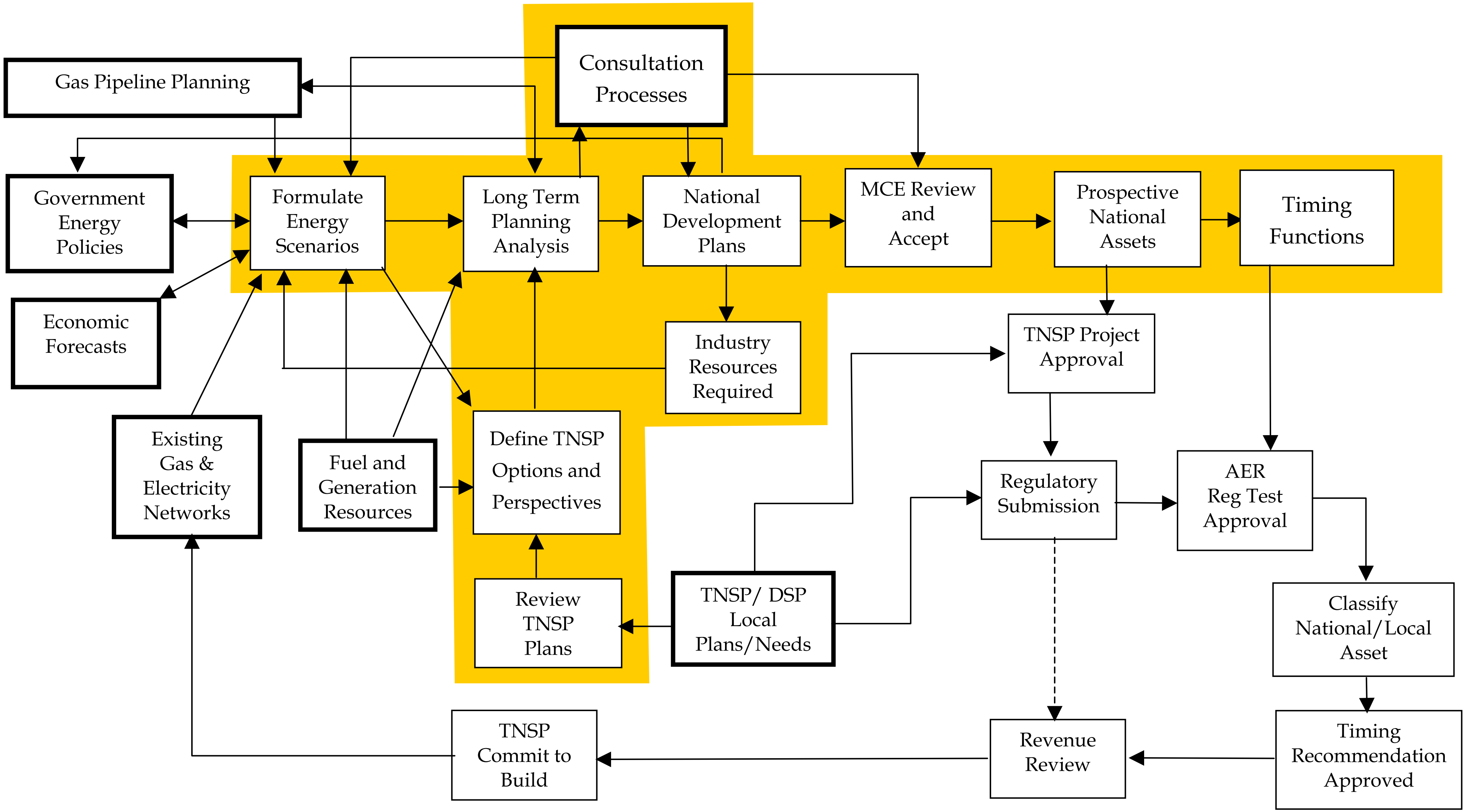


Table 2-1 Analysis of Aspects of Long Term Transmission Planning

Factor/Process	Type	Information	Sources
Economic growth forecast	Input	Trends in gross state product and the location of economic development.	Governments and agencies, AEMO
Demand growth forecasts	Input	Peak and energy demand growth by region and regional areas. Impact of demand side programs and embedded generation may be subtracted from total native demand.	AEMO
Existing state of networks	Input	Technical and economic performance of existing assets including remaining life.	TNSP
Energy policies	Input	Affecting fuel resources, preferred technologies, stimulus for demand side incentives emerging technologies, and emissions reduction targets	State and Federal Governments
Fuel Resources	Input	Location, energy reserves, projected costs, quarantined resources, production incentives	Companies and Government
Renewable energy resources	Input	Impacts of emission abatement programs on the location and cost of renewable energy resources	Government and industry associations
Gas pipelines	Input	Location and capacity of existing and prospective gas pipelines affecting opportunity for efficient gas fired generation	Gas pipeline owners
Easements	Input	Existing locations of transmission lines, unused easements and prospective future routes that may be available if needed.	TNSPs and Government agencies
TNSP options	Input	Development options that have been assessed as potentially needed as part of current TNSP plans.	TNSPs
Reliability and supply standards	Input	Specification of the quality of reliability of supply that is expected by customers	Governments with advice from market participants, Reliability Panel

Factor/Process	Type	Information	Sources
Regional and zonal forecasts	Analysis	Based on local and regional economic forecasts, household formation, industrial and commercial development	Government agencies, consultants
Identify generation options for fuel resources	Analysis	Formulate technologies for utilisation of fuel and renewable energy resources including cost and performance parameters	Proponents, industry associations, consultants
Connection options	Analysis	Formulate easement and transmission line options for connection of new generation regions to load centres and for development of expanding cities and regional towns.	TNSPs, consultants
Formulate scenarios of supply and demand matching economic scenarios	Analysis	Develop consistent economic analyses of how generation options would meet demand at least cost for each scenario, assuming indicative transmission costs.	TNSPs, consultants
Optimise transmission scenarios	Analysis	Review viability of transmission options for the supply/demand analysis to ensure consistency between generation and transmission options.	TNSPs, consultants
Confirm transmission performance standards	Analysis	Confirm that basic decisions about future voltage levels and network evolution is robust against the various scenarios. Confirm that reliability standards are economic relative to the cost of unserved energy.	TNSPs, consultants
Confirm major projects	Analysis	Identify the larger investments for long distance transmission and confirm that their basic design parameters are in the economic range and that they could not be delayed by improving the performance of the existing system using control technologies.	TNSPs, consultants
Confirm Development Plans	Output	For each scenario confirm the major network elements, their optimal sequencing and timing.	NTP, TNSPs, consultants

Factor/Process	Type	Information	Sources
Asset database	Output	Identify the major projects that are in the 10-year plan and the scenarios for which they would be economic. A range of timing would be provided for each asset over the scenario range as a function of market drivers.	NTP, TNSPs, consultants
Timing Functions	Output	Mathematical expressions that define optimal timing for defined projects as a function of market variables based on economic analysis completed to date.	TNSPs, consultants
Easements	Output	List of where new easements could be required in the next 20-30 years	NTP
Annual Transmission Plan	Output	A schedule of major projects for the next 10 years that provide material market benefits. A schedule of other projects derived from TNSP reports that form part of the planning but are primarily for local generation or load connection requirements.	NTP
Resource Plan	Output	A summary of annual capital and labour resources that would be needed to implement the plan together with potential supply constraints. This provides Government with economic and statistical information for economic management and associated infrastructure requirements.	NTP

The aspects of transmission planning that require a longer-term examination include easement acquisition and terminal station location to service future development areas. The development of gas pipelines also requires planners to take a long-term view, although gas pipelines are less problematic than electricity transmission lines because they are not so visually intrusive.

2.4.2 Analyses

The analyses which constitute the basis of development of a transmission plan involve the following steps:

1. Develop regional and zonal load forecasts
2. Develop cost and performance parameters for generation options from fuel resources and potential power station and pipeline locations
3. Assess the transmission connection requirements for generation projects and associated load development.
4. Formulate a set of economic scenarios containing available mixes of supply and demand resources and their associated costs which represent the potential range of developments in the electricity market having regard to energy policies and the patterns of growth.
5. Optimise the generation and transmission expansion plan for each economic scenario. Traditionally such analysis has assumed perfect foresight within each scenario. More sophisticated economic methods examine the optionality of investment choices in the presence of uncertainty represented by the various scenarios as well as the parameter sensitivities within each scenario. Expansion choices are then made to maximise economic value in the presence of uncertainty.
6. Assess the transmission design that would meet the optimal generation profile including load flow constraints, short circuit levels and dynamic stability constraints. At the planning phase, the amount of detailed design is limited to co-ordination of voltage and short-circuit levels to provide the basis for immediate equipment purchase. Not all design aspects would be fully investigated at the early planning phase. For example the choice of conductor size and the cost of losses would be evaluated in the design phase according to the prevailing cost of energy losses and conductor materials.
7. Assess the system performance at times of peak and low demand and assess whether the marginal value of constraints warrants design changes. In the long term planning phase such investigations may influence planning for control equipment to economically maximise the utilisation of HVAC assets where stability is a limiting factor.\
8. Develop Timing Functions which define the optimal timing of assets according to scenario variables related to supply and demand, either local or regional, and inter-regional power flow and pricing factors. Such functions allow timing to be reformulated as market forecasts changes without needing to repeat studies. Timing Functions provide information to market participants which enable them to formulate economic alternatives to network development. They would also allow other economic evaluations to be conducted where there are consequential impacts arising on transmission projects[1].

[1] For example, the viability of an embedded generator could be economically evaluated based upon its effect on the timing of future transmission developments. Currently there is no simple way to do this without commissioning extensive studies, the cost of which may not be commensurate with the value to that one specific project.. However, based on the

9. Confirm a development plan in terms of location, sizing and timing of new transmission assets by identifying the individual assets required and their optimal sequencing for each scenario.
10. Identify which transmission elements are common to a number of likely scenarios in the earlier periods. These are the options which are likely to have the greatest economic value when assessed in relation to uncertainty.

The upper left hand corner of Figure 2-1 shows the flow of information from the Government energy policies to the prospective national assets near the top right hand corner as the long-term plans are developed. This process would serve to:

- Confirm that the TNSP planned assets are consistent with the overall NEM development and sufficient to provide the required connectivity and trading within and between regions
- Identify where low cost resources are likely to be available and where existing transmission corridors may be inadequate to cope with future requirements. This would identify a class of assets that could not necessarily pass a market benefits test without including the potential future projects that might not have a proponent at the present time. An example in this group would be solar towers or geothermal resources from central Australia under a high carbon emission abatement scenario.
- Provide a basis for credibility that the regulatory approval process for an individual asset can be based on the broader background related to NEM development so as to identify longer-term benefits that may not be able to be contracted in the immediate future. This will of course raise the issue of how such strategic assets would be funded if the immediate benefits are not sufficient for short to medium term required financial returns sought by a private investor.

This development of a set of prospective plans and transmission should support the regulatory approval process and provide an overarching framework to confirm long-term viability of new transmission assets. The long term planning process would identify prospective assets that could be stranded if built under one scenario and then another emerges. An example of such an asset would be a new power line intended to provide access to additional coal fired power from a new mine which becomes non viable under a high emission abatement scenario, or a gas fired resource that becomes too expensive under a low emission abatement scenario.

planning studies, a formula which relates to relevant market factors can be readily developed from the base study information with only modest effort.

The planning could also be used to forecast requirements for labour and construction capacity and provide Governments with a basis to plan for training needs, something which has apparently been neglected in recent times. This resource requirement could then inform the very energy policies which Governments seek to implement. This highlights an example of where a national planning process could serve wider needs than just the planning and management of the transmission system itself.

The right hand side of Figure 2-1 illustrates that the national assets then become a basis for supporting TNPS project planning and regulatory submissions. The Timing Functions provide the basis for economic evaluation of other types of projects that would influence the timing of each proposed major transmission asset.

The Regulatory Test would identify whether an asset has NEM wide significance, rather than just local significance. Where an asset has NEM wide significance, it would be inappropriate to rely on the TNSP's own performance requirements being a sufficient driver to proceed with the investment. It would be necessary to make some portion of the TNSPs revenue depend on whether or not the national asset is developed in accordance with the Regulatory Test. This could amount to a 'contingent project' type approach in terms of incorporating an allowance for project of national significance. \

For a local asset, making revenue conditional on proceeding with the asset would not be necessary because the local reliability impacts or constraint based incentives should be sufficient to drive the investment.

Therefore, the EUAA proposes that a classification process would be conducted by the AER as part of the asset approval process which would determine whether the asset has NEM wide or material "national" significance. An asset that has material national significance would create a conditional revenue component when TNSPs revenue caps are determined. This would provide the TNSP the financial incentive to proceed with the project in a timely manner subject to the Timing Function analysis if the lead-time commitment is less than the available time to the current optimal timing.

2.4.3 Outputs

The outputs from the long term planning process would provide the following information:

- Specific development sequences for each scenario studied with the associated generation assumptions that are supported by that transmission plan. Capability to support variations around the base generation plan would also assist in defining the robustness of the plan.
- A set of transmission assets that may be required in successive 5 or 10 year periods under more than one scenario. These would represent the higher value assets that would be less likely to become stranded in the future.
- An estimate of the resources needed to implement each scenario in terms of capital and labour resources. This would provide the local and global industry with guidance for its own capacity planning and identify for Governments where training needs might need to be enhanced to meet future needs.
- Needs for future transmission easements to connect new resources.
- An assessment of bulk transmission requirements connecting the major regions and when new links are projected to be economic.
- For the major assets a description of the market drivers and their relative impacts that would make the development of the project a contributor to minimising the total cost of delivered electricity.

The level of detail required would be tested against a materiality criterion. By having an overall view of capital needs for the industry, AER would be assisted in validating capital investment requirements over time as part of the regulatory reset process. Where the need for new capacity coincides with a need to replace retiring capacity, the feasibility of the expenditure profile can be examined to see if resources should be devoted to accelerating some projects to avoid a financial crunch at a later time or investing in life extension of assets to delay replacement expenditure. Such analysis would form part of the justification of TNSP revenue caps.

2.5 Market benefits and reliability

The current regulatory test has two limbs. A new asset qualifies for a regulated revenue if it:

- Meets a reliability or technical standard at least cost, or
- Minimises the total delivered electricity market costs.

2.5.1 Reliability criteria

In the case where a proposed augmentation has no perceptible impact on the energy market or local generation resources, it may be deemed that a local reliability of supply criterion would be sufficient to determine an economic outcome. That criterion may be specified in terms of:

- N-X deterministic planning criteria where N is the number of independent paths of supply and X is the number of plant outages for which firm supply must be maintained. Typically N=2 and X=1 for normal supply arrangements and N=3 or more and X=2 for central business districts where local generation to provide full back up is infeasible. For local supplies requiring high security a back up generator would be installed to provide very high supply reliability;
- probabilistic standards for expected duration of interruption or expected frequency of interruptions to supply based on modelling of the reliability of continuity of supply; or.
- economic least cost criterion that minimise the total costs of supply and customer outages and from which economic reliability parameters are derived for measurement and modelling purposes and the development of reliability standards.

Wherever practicable in such circumstances, the EUAA would prefer a fully economic analysis which optimises customer reliability and considers demand side response opportunities from willing customers. There is always a risk that uniform technical standards can result in over-building in some situations, inadequate performance in high customer value situations and can discourage economic demand side responses. The analysis previously presented to the Reliability Panel on bulk system reliability showed the potential for acceptance of reliability standards that do not reflect the measurable economic impacts of supply interruption and the cost of providing reserve capacity.

2.5.2 Market benefits

Increasingly generation in the electricity market is becoming more distributed with increasing opportunities for embedded generation from gas or renewable energy resources. This means that transmission projects which involve a substantial increase in capacity may be deferred if embedded generation sources are developed or if occasional demand side response can reduce extreme peak demand to within plant capability. These opportunities may be assessed on a technical or reliability basis if their contribution can be adequately treated as a fixed resource unrelated to the energy market. However this approach is not strictly consistent with least cost in a market sense because demand side resources may respond to both local network constraints as well as prevailing energy market prices in the absence of local constraints. This means that the dichotomy between evaluations on the basis of reliability or market benefits is becoming less relevant as generation resources become more distributed. This trend is recognised in the MCE Scoping Paper.

Therefore, we might expect that the market benefits of all regulated transmission investments will need to be approximately estimated in the first evaluation step to assess whether there are any material market benefits that need to be quantified in more detail. The first step would assess what kinds of market benefits could be identified and their approximate binary order of magnitude using simple measures of capacity and energy savings. If it is concluded that the opportunity for the energy market to be influenced by a particular investment is negligible, then the focus may be on the least cost transmission development option having regard to customer supply reliability using deterministic or probabilistic planning criteria. There is scope for developing some standard methods that could be used for this initial screening process to identify which projects may need market benefits to be evaluated, or to make sufficiently accurate estimates where it is a small but significant part of the benefit. For example, a simple method for a transmission asset that provides access to the wider grid for low cost generating capacity could estimate a benefit in year (t) based on a formula of the form (* represents multiplication):

$$AMB_{(t)} = G_{(t)} \text{ x } O_{(t)} \text{ x } [LRM_{(t)} \text{ x } LFN_{(t)} - ALRMC_{(t)} \text{ x } LFN_{(t)}]$$

Where

$AMB_{(t)}$ =	Annual Market benefit in year t
$G_{(t)}$ =	Generating capacity enabled in year t
$O_{(t)}$ =	Operating hours per year (t)
$LRM_{(t)}$ =	Long Run Marginal Cost in year t
$LFN_{(t)}$ =	Loss Factor to Node in year t
$ALRMC_{(t)}$ -	Long Run Marginal Cost of Next Highest Cost Resource in year t

This formulation estimates the replacement cost of energy that would be otherwise inaccessible without the network development. The capacity enabled and the long Run Marginal Costs may well be a function of time (t) due to changing capital and fuel costs. Such a screening would require forecasts of price duration curves and new generation resource costs. When there is spare capacity, the Long Run Marginal Cost of the next highest resource might well be the Short Run Marginal Cost of an existing resource in which case the market benefits may be zero. Simple estimates would be used to assess the potential magnitude of these benefits on a present value basis to compare with the project present value costs.

Given the complexity of coordinating planning across the whole NEM, simple procedures of this nature would be useful to screen options for those that require market analysis and those that can be compared purely on simple project costs and performance criteria. The NTP could take a leading role in developing these methods and procedures so that the focus is maintained on the major transmission asset decisions, but with consistent approaches for assets of lesser importance. Of course, if it can be readily demonstrated that wider market benefits are negligible, then affected assets that are justified to address local issues and connections need not get caught up in national review processes.

2.5.3 Congestion management

Network augmentations have a direct effect on congestion and congestion has a direct effect on pool price differences across the network. Price differences result in economic costs due to constraints on the dispatch of low cost generation and they can have adverse impacts on some customers even if overall economic costs of congestion are minimal. An efficient transmission system is a constrained system at times because transmission capacity has an economic cost. Efficient constraints occur more frequently where long distances are involved because the cost of relieving constraints is greater.

Transmission investments on congested (or non-existent) transmission corridors may yield a net reduction in the total operating costs for the generation system after allowing for transmission losses. It is then a question whether these savings are sufficient to justify the cost of the transmission link over its economic life as compared to alternative measures based upon local energy resources available for power generation, or in extreme cases relocation of demand.

Customer impacts arising from a transmission augmentation may be adverse on the exporting side of a relieved constraint because energy prices may rise due to the increased exports and the customers may also bear some of the costs of the network augmentation if there is a distortion of the beneficiary pays principle[2].

For example, the connection between Victoria and Tasmania through Basslink increased the prices in Victoria because of the shortage of hydro generation in Tasmania due to the drought. Fortunately, Victorian customers do not bear the costs of Basslink which are in part carried by the Tasmanian customers indirectly through (previous) Government ownership of Hydro Tasmania. The offsetting benefit is Basslink has secured electricity supply in Tasmania against severe drought and this is currently being demonstrated.

[2] It would be unreasonable for customers to contribute to the cost of a transmission augmentation that increases their energy costs or reduces their relaibility of supply, or both.

Another related benefit of reducing constraints is that it increases inter-regional competition in power generation. This may have a slight impact in economic efficiency but usually a greater impact on customer benefits through reduced prices. Some generators may also benefit through more efficient dispatch of lower cost resources.

2.6 Summary

There is a scope for conducting a long – term planning process that provides a strategic framework for evaluating transmission development projects in the face of uncertainty relating to future energy market conditions and prospective government policies. Using scenario and option analysis, it would be possible to identify major projects that would be required to minimise the delivered cost of electricity and maintain the required quality of supply. A transmission plan would consist of more than a list of future assets. It would describe the functional relationships between the relevant market drivers and the optimal timing of proposed assets so that energy market participants can maximise their own contribution to minimising total delivered electricity costs.

3 RESPONSE TO QUESTIONS

This chapter provides a consolidated response to the Scoping Paper questions with reference to the foregoing analysis. In each case the question from the Scoping Paper is repeated at the start of section below. In some cases there is necessary repetition in responding to some questions which are of a general nature.

3.1 General Requirements

The Commission is seeking general comments on the issues identified by COAG, the approach to assessing the enhanced arrangements for network planning against the NEM objective, and the basis for identifying and selecting between options for the implementation of those enhanced arrangements.

The EUAA supports the recommendations of ERIG and COAG's response to the ERIG report. The role of the NTP must be distinct from the TNSPs to avoid duplication of effort and the risk of inefficiency arising from market participants working at cross-purposes. Incentives facing TNSPS may also differ from the incentives or drivers that would be considered by an NTP in planning the future augmentation of a national network.

The NTP's planning focus should:

- Assess the impact of Government energy policies;
- Monitor technology trends affecting transmission development;
- Monitor the development and competitiveness of fuel sources and new generation sites;
- In conjunction with stakeholders, identify suitable supply scenarios that represent the possible range of futures that may need to be addressed including potential changes to Government policies to address emerging issues that may not have a current focus;
- Identify the network development options which have already been established by TNSPs and their stated purposes and economic benefits, and the way that these developments fit with, and can be best utilized in the national planning process;
- Coordinate the use of technical and economic analysis to identify potential augmentations and the timing of those augmentations that would serve the market needs at least cost for the chosen scenarios;
- Create standard procedures and documentation processes for the economic and technical evaluation of gas and electricity transmission development projects;
- Facilitate communication among stakeholders in the electricity market supply chain from fuel suppliers to customers.

This activity would be conducted through the processes described above in Chapter 0. The analysis work may be commissioned through consultants and TNSPs, rather than the NTP having a large technical staff. The NTP would review TNSP plans especially where there are interactions between separately planned and owned networks to ensure that a NEM focus on cost minimisation and performance assessment is sustained. Where TNSPs have already demonstrated efficiency and effectiveness in developing their own networks for local and regional purposes, the NTP should focus on the evaluation of the national benefits of those options rather than refining existing plans. The NTP should focus on the planning and coordination gaps in space and time rather than attempt to shadow all TNSP activities and decisions. The only role that the NTP would have in TNSP activities would be in developing process standards that would be applied by TNSPs in preparing economic evaluations. For example, having standard scenarios would assist in the co-ordination of planning work across the TNSPs.

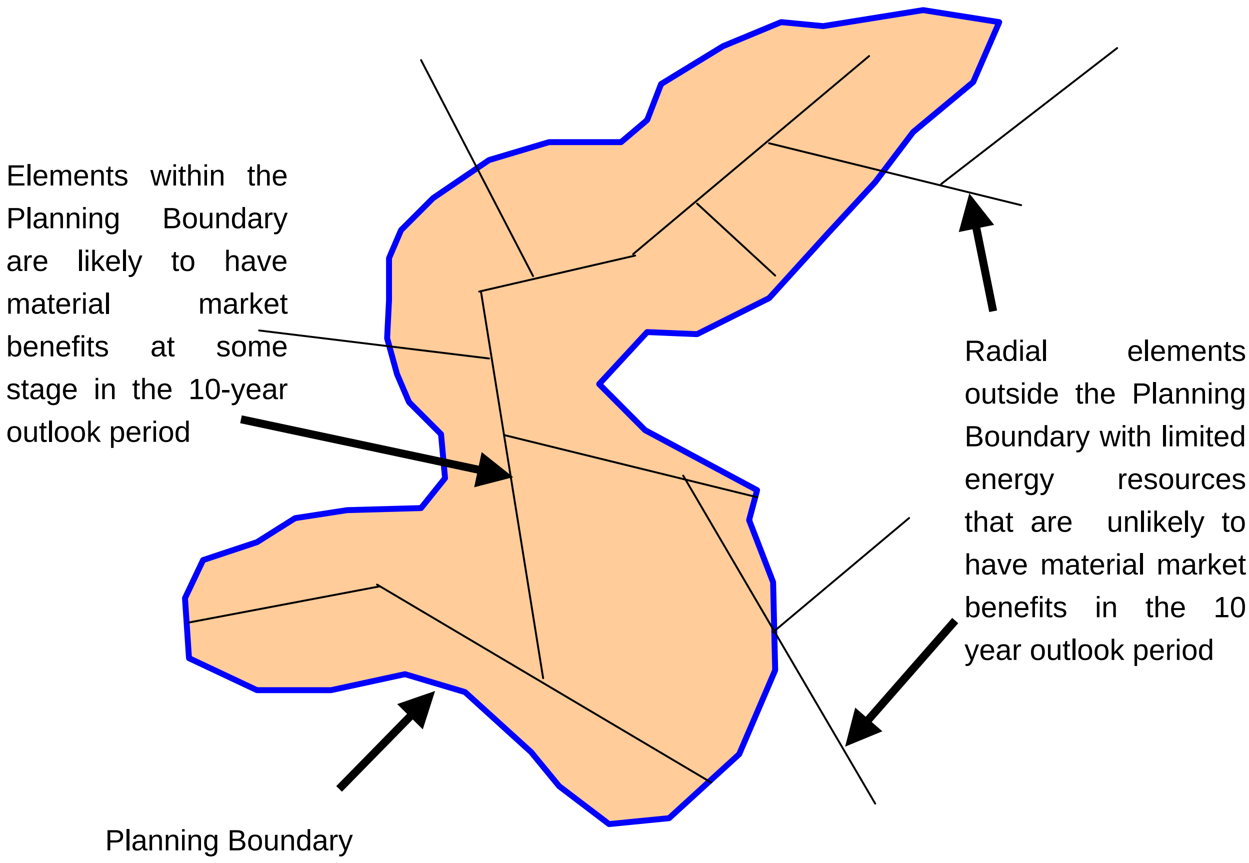
3.2 Planning Boundary

It may be useful to define a “Long-Term Planning Boundary” (or “*Planning Boundary*” for brevity) around the transmission and subordinate networks within which developments would be expected to have material market benefits of say at least 10% to 20% of the cost of new developments. The NTP would focus on the network elements within this *Planning Boundary* for the purposes of evaluating market benefits and continually review where the *Planning Boundary* may be extended or retracted to indicate the focus of its attention.

Radial networks serving areas that are energy resource poor may be excluded on the basis that market benefits of assets serving such areas would be expected to be negligible or the market benefits could be readily assessed based on local circumstances.

The *Planning Boundary* could be reviewed every five years or as necessary for changed circumstances. An example of conditions signalling the need for a *Planning Boundary* change would be when currently excluded easements or assets can be found to connect to significant energy resources that may become commercial within the next (say) 20 years. The concept of the *Planning Boundary* is illustrated in Figure 3.1. As the National Planning Process develops, the size of the *Planning Boundary* might be more limited initially to limit the risk of organisational overload.

Figure 3-1 Planning Boundary concept



3.3 Governance consultation and communication

The Commission is seeking respondents' views on the appropriate governance, consultation and communication arrangements for the new National Transmission Planner.

3.3.1 Organisational arrangements

COAG Ministers have agreed that the NTP will be located in the AEMO. An important question is the relationship between the AEMO and the NTP particularly if the AEMO is established as a corporate entity.

The advantages of keeping it within the AEMO rather than in a separate entity are that:

- It would have ready access to energy market data for evaluation purposes
- It would have access to technical expertise

- It would be more efficient administratively not to have to set up a separate organisation with Board and management overheads.

The disadvantages are that:

- Potential conflicts of interest and resources between the planning and operational functions
- Its resources could be diverted into assisting with short-term operational matters rather than maintaining the long-term focus on the transmission system.
- Its activities may become invisible due to all the other roles of AEMO
- Funding and budgetary considerations
- Accountability and the relationship with the AEMO directors

The EUAA believes that it is essential that the NTP is able to operate free from any parochial interests. The establishment of AEMO is being addressed in another forum but the EUAA considers that the Consultation Paper should address the issues that would affect the NTP's organisational performance and that a suitable management structure should be set up to maintain the NTP's independence from TNSPs, dominant market participants and political influences, other than directions publicly given by the MCE after consultative processes.

3.3.2 NTP Objectives and Activities

As the NTP has a substantial role affecting the economic development of the NEM, its objectives should be set by the MCE under policies developed by COAG. The NTP may operate best with independent oversight and management with technical and commercial expertise to expertly direct the planning processes. The NTP would prepare and publish annual plans with the level of detail progressing over several years as it develops its internal processes and external consultative processes. More detail would be provided for the 7 to 10 year horizon with specified assets identified. For the 10 to 30 year horizon, the level of detail would be less, with the major focus on interconnections and long distance transmission needs between load and generation centres. The NTP would prepare detailed evaluation documents to show how it has developed its plans and discuss the limitations of the analysis that has been used to develop the plans. A practical review schedule assuming that the drivers of timing are published would be as summarised in

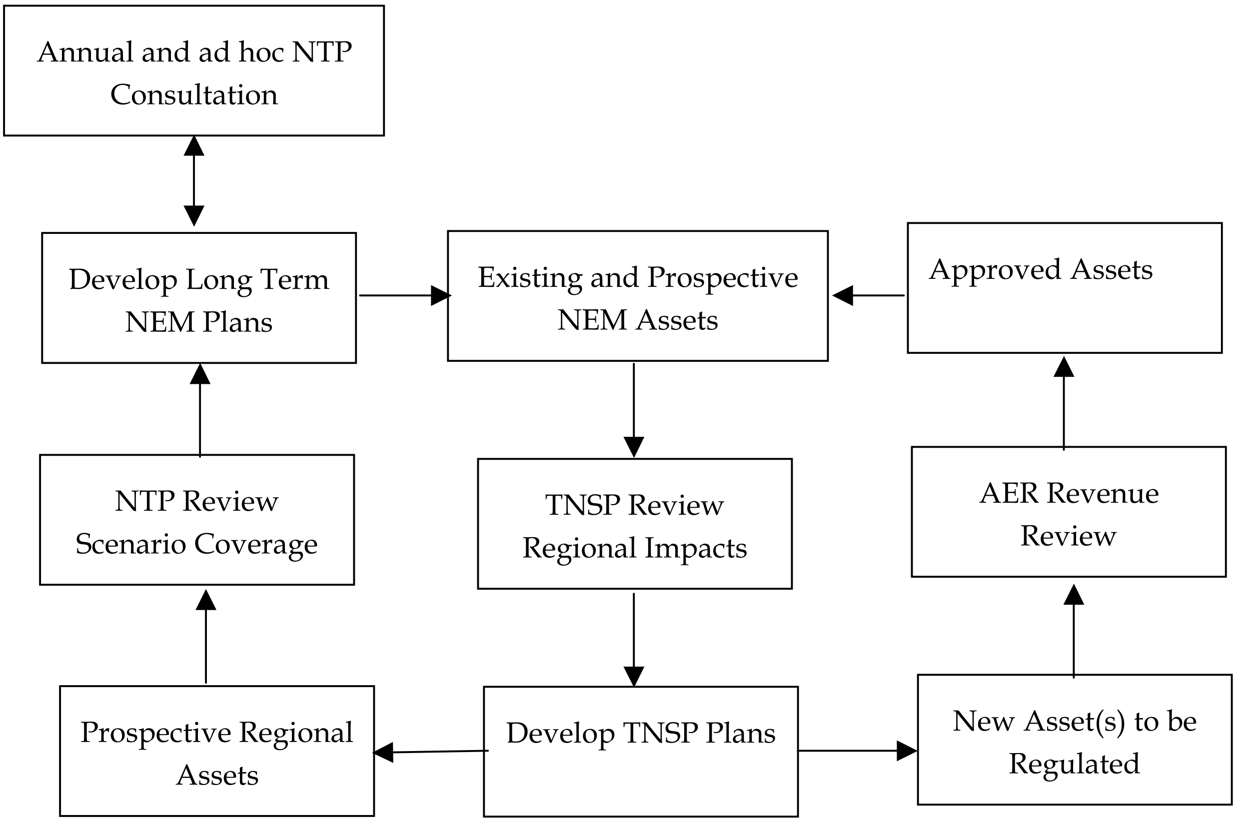
Table 3-1. Providing *Timing Functions* are available that define optimal timing as a function of market variables, the need for assets can be continually reviewed without detailed economic studies. Lead times over 5 to 7 years time horizons should be reviewed annually. The medium term from 5 to 15 years need only be reviewed energy 2 to 3 years and the longer term to 30 years, about once every five years or if major energy policy changes occur, such as emissions trading.

Table 3-1 Review periods

Planning Horizon	Review Frequency	Comment
5 – 7 years	Annually	So that lead times to requirements are actively monitored
5- 15 years	Every Two years	Providing timing functions are developed
15-30 years	Every Five years	To review long-term objectives, easement requirements and asset replacement plans

The NTP would also review TNSP 5 to 10 year plans and identify which of the NTP scenarios are supported by these plans and which scenarios are not supported, if applicable. Any significant risks would be identified where economic generation sources may not be able to be developed under the prevailing TNSP plans. This feedback process would be intended to improve the subsequent planning processes. This feedback element is illustrated inFigure 3-2. An iterative process from year to year would assist the convergence of transmission plans across the NEM if it could not be all accomplished in one year or in one gigantic round of analyses. Given the complexity of the task, a continuous iterative process with annual consultative processes that bring forward changes to the planning outlook would be essential.

Figure 3-2 Planning Review



The complexity of integrating fuel, generation, transmission and emission analysis should not be under-estimated. It is likely that an iterative process undertaken on a one to two year cycle could approximate an effective economic analysis that would be impractical to assess in one round. The major problem is that by the time the analysis is complete, the assumptions would already be outdated. However, such a process shown in Figure 3-2 would occur as the NTP and the TNSP plans are reviewed by the respective entities and by stakeholders in consultation processes from year to year and one would expect the processes to identify new opportunities to better co-ordinate TNSP plans in the context of whole of market scenarios covering fuel, generation, emissions and transmission.

3.3.3 Planning cycle

If the NTP process is conducted properly having regard to market uncertainties, then it ought not to be necessary to conduct a full review of all developments every year. Indeed, it may be inefficient to complete on an annual basis because long term planning issues should not change very much over a one-year period. If the focus remains on the long-term, then a 2-3 year major review cycle would be sufficient with the intervening time focused on monitoring TNSP developments and providing regional updates or specific analyses of issues, such the impact of particular trends like nuclear power, coal seam gas, renewable energy on the network as a whole. Methods which describe the optimal timing of the construction of prospective assets according to market variables would increase the value of the analysis undertaken and allow market participants to contribute to the cost optimisation process.

Updating plans on a year-to-year basis in terms of timing and sequencing would be a TNSP responsibility, rather than a major NTP priority.

3.4 Planning within Jurisdictions

The Commission is interested in views on the appropriate scope of the review with respect to planning arrangements within jurisdictions, and their interaction with national planning arrangements

The EUAA does not consider it feasible for all the planning to be conducted centrally for the NEM and NGM and the current roles of the TNSPs would continue substantially unchanged during the early phases of the life of the NTP. After the first National Transmission Network Development Plan (NTNDP) is published, TNSPs would thereafter be expected to review their plans in terms of the scenarios presented in the NTNDP or alternative scenarios that may be better adapted to local uncertainties. Such adaptation would then be expected to feed back into the next national review.

The EUAA supports the COAG view that the establishment of the NTP need not change existing TNSP responsibilities. The focus of the NTP should be on co-ordination and longer term planning issues that affect the NEM as a whole or at least affect two or more regions or two or more TNSP service areas.

Alignment of reliability standards on an economic basis across the NEM may also be a desirable goal so that planning is on a consistent basis among the jurisdictions. This would assist the co-ordination process, and allow standard methods of economic evaluation to be developed and applied across all TNSPs and the NTP.

3.5 The Scope of National Planning

The Commission is interested in respondents' views on whether the principles for identifying the national transmission system have been resolved and correctly applied, or whether there is further work to be done to identify the appropriate area of focus within the transmission network for the National Transmission Planner.

The focus of work for the NTP should not be too tightly defined. The NTP's focus should be driven by economic criteria in such terms as:

- Parts of the transmission network that provide significant market benefits related to the supply and demand for electricity as per the concept of *Planning Boundary* as defined in section 0.
- Technical and economic issues that influence the national and inter-regional role of the transmission system, such as the development of fuel and energy resources, renewable and otherwise.
- Responding to government enquiries that have an influence on energy policy, provision of infrastructure and future capital and labour needs for the industry.

Since transmission has an integrating role in electricity systems, the NTP may be involved in developing economic analyses, consultation papers and evaluation reports over the whole supply chain to the extent that decisions about future transmission connections could have a significant influence on government and industry decisions.

The NTP may also develop planning standards and procedures to improve economic analysis across the supply chain. The definition of standard supply and demand scenarios may assist understanding in managing and communicating the impacts of energy market uncertainty on economic evaluations.

3.6 Last Resort Planning Power

The Commission is interested in comments on the appropriate institutional arrangements for the last resort planning power, and the implications for the functions of the National Transmission Planner.

The NTP would be a suitable entity to exercise the Last Resort Planning Power or at least to advise AEMC the reasons and timing for which it would need to be exercised. The NTP would have an appropriate high-level view of where benefits could be created by new transmission projects that are not already part of TNSP annual plans. The NTP would be accountable to the AEMC when exercising the role.

A properly functioning planning process would provide TNSPs and other infrastructure investors with sufficient information to identify projects that would pass a Regulatory Test and become attractive investments. Thus the existence of the NTP would reduce the risk that the Last Resort Planning Power would need to be exercised.

3.7 Ensuring Effective Interaction with TNSPs

The Commission is interested in respondents' views on how best to ensure effective interaction between TNSPs and the National Transmission Planner, while also ensuring that the National Transmission Planner adds value through a stronger focus on the national network.

The key success factor will be to ensure a cooperative approach between the NTP and TNSPs. This would work most effectively if:

- There is no overlap of responsibilities with clear boundaries
- There is minimal duplication of effort on planning activities
- There is mutual dependence in maximising the value of planning activities
- There is a standard method for defining the optimal timing of related projects so that the value of sophisticated economic analysis can be maximised across the electricity supply chain.

The focus of the NTP activities should be the long term and the broader market drivers rather than local circumstances. The NTP may bring forward potential projects that have been overlooked by TNSPs or which fall between regions in a way that makes coordination problematic. The focus of the TNSPs should remain on the assessment of local and the delivery of projects that satisfy the Regulatory Test.

Where the NTP must coordinate inter-regional projects with multiple TNSPs, it would be the NTP's role to set up working groups as needed to bring projects to the point where a credible economic evaluation can be publicly presented as the basis for Regulatory approval. It would be preferred if the NTP critiqued, rather than being responsible for the commissioning and conducting of economic analyses into the feasibility of new inter-regional projects. This would place planning performance discipline on TNSPs and provide an audit process for review of evaluations. If necessary, the NTP could engage independent consultants to review TNSP analyses work where the analysis s not easy to comprehend and validate. This may be useful where specialised market modelling software has been used to estimate market benefits.

Primarily the incentives on TNSPs to participate in planning activities with the newly formed NTP must be positive:

- TNSPs must want to work with the NTP so that their regulatory work will be credible in the national context;
- The NTP must allow the TNSPs to do the analysis with the assistance of guidance on standard procedures so that such work becomes integral to their own project evaluations;
- The NTP should assist the TNSPs with scenario formulations related to government policies and broader market issues; and the NTP should be able to use the project option information provided by TNSPs so that all analysis uses the best local information.

This can be achieved with clear responsibilities and the establishment of working arrangements that facilitate exchange of information and modelling functionality.

Figure 2-1 showed how the NTP activity feeds into the TNSP's regulatory project approval activity and the project development work of the TNSPs feeds back into the national evaluation of scenarios. The administrative arrangements should be structured to follow these processes at various times.

3.8 Aligning regulatory reviews

Determining the appropriate approach to alignment will entail consideration of both the costs and benefits of alignment. Respondents' views are sought on the costs and benefits which should be considered within the review.

The practicality of aligning regulatory reviews across the transmission grids is questionable because of the resource peaks and troughs it would create for the AER and consulting companies. There are significant levels of activity involved by TNSPs, industry associations and their consultants in participating in regulatory reviews. To attempt to conduct all the transmission review at one time across the NEM would create severe resource constraints in most circumstances. We have seen recent evidence that SP AusNet AusNet have acknowledged the resource-intensity of both t he gas and electricity review process and have sought to extend the normal five-year regulatory cycle by one year for the electricity transmission business to ensure that there is sufficient space between its gas and electricity reviews.

Providing the overall planning framework has been established through the NTP process, then it should not matter too much where a particular TNSP is in the planning cycle. There has been an incentive for TNSPs to seek approval for overall capital expenditure in a regulatory review and then to defer that expenditure as much as possible during the regulatory period so as to improve profitability. However, to ensure that development incentives are aligned to market benefits, the NTP process should make TNSP revenue associated with national assets conditional on those assets being commissioned or committed. This would provide a focus on the timely delivery of such assets. The NTP may have a role in overseeing the optimal timing of approved assets when they have been accepted into the revenue cap on a conditional basis.

3.9 Confirming efficient investment requirements

The Commission is interested in respondents views whether simultaneous revenue resets would assist the AER in forming views on efficient investment requirements from a national perspective. If so, what approaches to the conduct of the review would best realise that benefit?

It is not necessary to have simultaneous revenue reviews to obtain consistency in planning providing that the AER can readily assess the inter-related nature of developments at any time in the regulatory cycle. The planning and regulatory approval process can be considered to consist of four parts:

1. identification of the projects that have a high probability of being economic in the planning period, say of 10 - 20 years depending on their nature
2. confirmation of when those projects would be optimally timed and monitoring that timing on an annual basis or more frequently when market circumstances change if there are drivers other than demand growth
3. commitment to regulatory approval of expenditure and making provision for recovering the cost of the asset in the regulatory revenue cap
4. refinement of the final timing of commitment to construction according to the specific conditions precedent.

Normally items 3 and 4 happen at the same time if approval has been achieved commensurate with the necessary lead time. However, if a transmission line project was related to a block of generating capacity reaching a certain peak performance level, then the optimal timing may become conditional on market events and final commitment might be some time after the formal regulatory approval in accordance with the principle of maximising market benefits, including the cost of the asset.

Proving these processes are working effectively, the AER should be able to take the current planning and project information at any time and formulate a conditional revenue base for a TNSP in relation to projects with substantial market-related benefits. This would require project drivers to be identified during the planning process and for the key sensitivities that affect optimal timing to be recognised in the economic analysis. Such sensitivities may be codified so that optimal timing can be monitored between planning reviews. For example, the optimal timing may be a function of several parameters such as:

- peak demand
- peak power flow on an existing asset
- an aggregate generation level at one or more locations
- a peak ambient temperature
- an inter-regional power flow
- an inter-regional price difference.

The EUAA proposes that a *Timing Function* would be created for each proposed transmission asset. The *Timing Function* would be used to indicate the optimal timing of national assets by regulators between planning reviews as a function of the major drivers of economic benefit of the proposed project. The *Timing Function* would be an outcome of the planning analysis that identified it as a potentially viable option. Providing *Timing Functions* are available, the planning adjustment process may be approximated between annual or less frequent reviews.

Such *Timing Functions* being published in planning reports would also provide other market participants with useful information about the market costs and net benefits of particular projects so that they may identify alternative resources that could delay prospective and approved transmission projects on an economic basis. Currently the TNSP planning statements rarely state the main drivers for key projects in any adequate detail and generation and demand side proponents cannot make reasonable assessments about alternative responses to market needs. Regulators would be able to conduct their revenue reviews if such planning information were available for the major projects of national significance.

3.10 Synergies from simultaneous reviews

> The Commission is seeking views on where the greatest synergies may arise, and whether these are likely to be material enough to justify modification to the timetable for reviews. The Commission also seeks views on what disadvantages may arise from aligning the timetables.

Aligning the reviews would provide customers with consistency across NEM regions in that network charges would be on the same WACC basis in the same time period in all regions. This would ensure that end users in all regions face the same relative cost signals.

The EUAA believes that there are advantages in aligning the revenue reset processes and this has been further increased by the revisions to Chapter 6A of the National Electricity Rules which have greatly reduced the flexibility and effectiveness of the AER in arriving at determinations based on timely inputs.

However it is apparent that there remains the disadvantage of creating peaks in workload for the AER, stakeholders and supporting consultants which would add costs to the review process. On this basis it would seem to be best to aim for a consistency of revenue basis within the same time periods and across NEM regions whilst allowing for the reviews to take place at different times. Full consistency may not be fully achievable because at different review times the perceptions of growth and financial risk parameters will differ. Inevitably there is a trade-off between these conflicting objectives.

The consistency of regulatory reviews, irrespective of when they are undertaken, would be made stronger if the National Transmission Plan underpins and informs the TNSP planning process, and the inputs and market assumptions for the regulatory reviews.

3.11 Definition of Market benefits

The Commission is seeking respondents' views on the problems in the definition of market benefits, or the application of that definition, which lead to a failure to consider broader market benefits. The Commission is also seeking views on the responses that should be considered.

One of the major deficiencies of the current Regulatory Test is that the acceptance of the project on the basis of the reliability standard automatically assumes that market benefits are negligible. This is reinforced by the absence of public information about the customer reliability impacts and underlying cost and value drivers for particular investments. As discussed above in section 3.9, the provision of information about the timing drivers, in the form of *Timing Functions*, whether they be predominantly reliability-based or market-based would facilitate more informed proponents to come forward with well developed lower cost alternatives if they are available, or be able to further enhance the value of proposed transmission developments so that they may be advanced.

For example, many transmission line projects have been in Planning Reviews for many years and yet nowhere can an inquirer assess the factors that determine timing even in an approximate way. Therefore the uncertainty in timing cannot be independently assessed. If the relationship between the growth in peak demand and timing for construction could be defined, then the relationship between timing, load growth and demand side response could be used to screen projects that would have otherwise have an economic and material impact on project timing for that particular project. Since proponents of demand side response or embedded generation cannot assess the relative viability of their projects they are not well equipped to provide credible alternatives when they are needed by the regulatory and planning processes.

No wonder the demand side is struggling to deliver the expected benefits!

The EUAA proposes that the planning assessment framework could be improved by provision of relevant information about the timing drivers for major network projects in terms of specified reliability, changes in peak demand and inter-regional power flows and price differences, and project costs. When the market factors are shown to be negligible, the reliability basis could be adopted without significant change. Where the market benefits could influence the optimal timing of a project, then timing drivers need to be published well in advance so that viable projects can be developed and earn a revenue that is linked back to the avoided investment where the linkage can be fully demonstrated.

3.12 Institutional arrangements

The Commission is interested in views on how the review should address the interaction between the new National Transmission Plan, the institutional arrangements for the transmission last resort planning power, and the institutional arrangements for the new network planning and consultation process.

The EUAA supports the continuing obligations of TNSPs under current arrangements. The role of the NTP will be to conduct the long term and inter-regional coordination planning that has previously relied upon the activities of the Inter-Regional Planning Committee. The NTP would also provide information back into energy policy development related to the resources needed to develop the transmission system to meet future patterns of energy demand and consumption. This may become more critical under emission abatement scenarios where there could be major shift in the patterns of electricity demand and electricity generation and the location of the lowest cost energy resources.

4 CONCLUSIONS

The EUAA supports the proposal to develop a National Transmission Planning function to coordinate the long term planning of the transmission system in the NEM and the NGM. The development of network plans from energy supply and demand scenarios is a complex task that requires coordination of inputs from across the whole electricity value chain from energy sources to customers.

The EUAA supports the recommendations of ERIG and COAG's response to the ERIG report in respect of the establishment of a national transmission planner. The role of the NTP must be distinct from the TNSPs to avoid duplication of effort and the risk of inefficiency arising from market participants working at cross-purposes. NTP's planning focus should:

- Assess the impact of Government energy policies
- Monitor technology trends affecting transmission development
- Monitor the development and competitiveness of fuel sources and new generation sites
- In conjunction with stakeholders, identify suitable supply scenarios that represent the possible range of futures that may need to be addressed including potential changes to Government policies to address emerging issues that may not have a political focus currently
- Identify the network development options which have already been established by TNSPs and their stated purposes and economic benefits
- Coordinate the use of technical and economic analysis to identify potential augmentations and their timing that would serve the market needs at least cost for the chosen scenarios
- Create standard procedures and documentation processes for the economic and technical evaluation of transmission development projects
- Facilitate communication among stakeholders in the electricity market supply chain from fuel suppliers to customers.

It is not reasonable to expect TNSPs to play their full part in this process without some direction in formulating scenarios, options and methodologies that would facilitate coordinated evaluation.

A more transparent process that provides useful information about the economic value drivers for transmission development would also assist market participants to bring forward supply and demand based projects that could be used to defer the network developments or enhance their economic value.

Some proposals that are presented in this Response towards more effect planning processes include:

- Requiring the NTP to coordinate a long term planning process that develops energy supply scenarios having regard to current and prospective government energy policies. These scenarios would then be used to identify the transmission network elements that would be required to minimise the delivered cost of electricity for the alternative scenarios, preferably with regard to the uncertainty between and within those scenarios.

- Requiring the NTP to describe and maintain a Planning Boundary within which transmission assets are likely to create significant market benefits if they were to be removed or augmented. The Planning Boundary would assist in maintaining focus on the main game of maximising the value of the whole NEM transmission system. The Planning Boundary would be varied periodically and as necessary to ensure that transmission assets and areas that contribute broader market benefits are included.

- Requiring the NTP to develop standard procedures for screening options for the applicability of market benefits in their economic evaluation. This would help to focus analytical resources where significant market benefits are to be evaluated.

- Creating a standardised method for conducting an initial market benefit screening on all significant transmission projects to identify if market benefits would offset more than 10% to 20% of the present value costs of a transmission project. If so, the maximising of market benefits would need to become an objective in the approval process, rather than merely focusing on reliability criteria.

- Defining Timing Functions that describe the optimal timing of a proposed transmission asset in terms of measurable energy market variables based on economic evaluations completed to date. Such Functions would facilitate market participants finding more economic alternatives which could be used to defer or avoid the proposed project.

APPENDIX A COAG DECISION ON NATIONAL TRANSMISSION PLANNER

This appendix extracts the elements of the COG decision of 3rd July 2007 in relation to the National Transmission Planner.

Attachment A

Council of Australian Governments' response to the final report of the Energy Reform Implementation Group

Attachment A sets out the Council of Australian Governments' (COAG) response to the final report of the Energy Reform Implementation Group, as contained in the COAG Communiqué of 13 April 2007.

ENERGY REFORM IMPLEMENTATION GROUP – COAG RESPONSE

At its meeting on 10 February 2006, COAG agreed that, while structural reforms taken under the National Competition Policy and other COAG initiatives have significantly improved the efficiency of the energy sector, further reform is needed to ensure Australia retains secure energy markets and relatively low electricity and gas prices. To this end, COAG recommitted to the broad ranging reforms being implemented by the Ministerial Council on Energy (MCE) and established the Energy Reform Implementation Group (ERIG) to develop proposals for:

- achieving a fully national electricity transmission grid;
- measures that may be necessary to address structural issues affecting the ongoing efficiency and competitiveness of the electricity sector; and
- any measures needed to ensure transparent and effective financial markets to support energy markets.

COAG thanked the Chairman of ERIG, Mr Bill Scales AO, and the panel members, Mr Geoff Carmody, Mr David Swift and Mr Alan Rattray for their report and for their extensive consultations across industry and government.

ERIG found that Australia's energy market is respected internationally as one of the most competitive and efficient in the world. However, COAG has accepted ERIG's view that there is scope for further reform to maintain productivity improvements and better equip Australia for its future energy needs. In response to the report, COAG has agreed to a broad ranging reform agenda that will improve competition, governance, infrastructure planning and the financial markets within the energy sector to provide a stronger industrial base for Australia's future prosperity.

1. Governance

COAG affirmed its confidence in the new energy market governance arrangements created in 2004-05 and noted that the Ministerial Council on Energy (MCE) as policy-maker and legislator, the Australian Energy Market Commission (AEMC) as rule-maker and market developer, and the Australian Energy Regulator (AER) as economic regulator, are all performing well.

COAG noted that, consistent with ERIG's recommendations, the MCE has recently completed an efficiency review of the AEMC and committed a significant increase in funding and is currently progressing amendments to AEMC rule-making legislation to assist the AEMC to better manage its workload. COAG also notes that the MCE is utilising independent expert groups to assist in the energy market reform program where appropriate.

In addition, COAG has endorsed a number of ERIG's recommendations to further improve energy market governance through the following commitments:

- establishing a National Energy Market Operator (NEMO);

- ensuring the governance arrangements for the NEMO involve market participants in board appointment processes, in a manner that preserves the board's independence from any particular market participant;
- introducing a national transmission planning function; and
- strengthening its commitment to energy market reforms through a requirement for the MCE to report annually on progress in implementing energy reforms to the COAG Reform Council to ensure agreed timelines are met.

COAG considers that these new governance arrangements will provide a solid foundation for the long term development of Australia's energy market. The performance of the new energy market governance arrangements will be examined five years after their commencement.

COAG noted ERIG's advice on the significant potential benefits arising from privatisation and/or disaggregation of energy assets remaining in government ownership. COAG agreed that any decision on privatisation or disaggregation initiatives is a matter for individual governments.

2. National Energy Market Operator

COAG has agreed to establish a single industry funded NEMO, for both electricity and gas, to strengthen the national character of energy market governance. COAG has tasked the MCE with developing, in consultation with stakeholders, a detailed implementation plan by the end of 2007 for establishing the NEMO with:

- the NEMO's functions to encompass:

  - responsibility for the day to day operation and administration of the power system and electricity wholesale spot market in the National Electricity Market (NEM) (as currently performed by the National Electricity Market Management Company (NEMMCO)), and
  - the planned Gas Market Operator (GMO), as well as the new national transmission planning function; and
- consideration to staging the establishment process for the NEMO with a transitional GMO, based on consultation with stakeholders.

The creation of the NEMO recognises the convergence of regulatory frameworks for gas and electricity as well as the economies of scale and scope arising from a single interface with energy industry participants. COAG agreed with ERIG that the NEMO should include stronger stakeholder participation and responsiveness, and has asked the MCE to develop:

- a process for appointment of an independent skills-based NEMO Board with a balanced mix of industry and generalist expertise, appointed under statutory conditions by the MCE; and
- a Market Operations Panel (or panels) for electricity and gas, to advise the NEMO Board.

COAG noted the MCE's progress in considering the establishment of a national Gas Market Operator (GMO). The GMO, if established, would be expected to subsume the gas market functions of VENCorp, the Gas Market Company (GMC) and Retail Energy Market Company (REMCo), and have responsibility for the operation of a bulletin board and short term trading market for gas. COAG agrees with ERIG that the development of the NEMO should not delay implementation of these significant gas market development initiatives.

3. Electricity Transmission Planning and Regulation

Development of a national electricity transmission grid (excluding WA and NT) has been central to energy market reform over the last decade. ERIG has made a number of recommendations to enhance national transmission planning and regulation.

COAG has agreed to establish an enhanced planning process for the national electricity transmission network to ensure a more strategic and nationally coordinated approach to transmission network development, providing guidance to private and public investors to help optimise investment between transmission and generation across the power system.

The National Transmission Planner, located in the NEMO, will be required to develop a strategic National Transmission Network Development Plan (NTNDP) outlining the broad development of the power system, including the current and planned future capability of the national transmission network and development options. The NTNDP will be produced after wide consultation with relevant stakeholders, have a minimum outlook of ten years and be updated and released annually.

These new arrangements will be designed to provide an appropriate balance between the delivery of a coordinated and efficient national transmission grid, and local and regional reliability and planning requirements, and be flexible enough to respond to generation and load changes. They will replace the current Inter Regional Planning Committee and Annual National Transmission Statement.

The NTNDP will provide information to the market on the longer term efficient development of the power system in order to guide network investment decisions and provide signals for efficient generation investment. The NTNDP, however, will not replace localised transmission planning, bind transmission companies to specific investment decisions, override TNSP performance obligations, or constrain the timeframes for the revenue approval process of the transmission companies. Accountability for transmission investment, operation and performance will remain with the transmission network service providers.

These arrangements are intended to assist transmission companies, when undertaking planning and putting forward their revenue proposals to the AER, to demonstrate that projects are aligned with the NTNDP. In turn, the AER will have regard to the NTNDP and the advice of the National Transmission Planner when making revenue determinations. The NTNDP will not bind the AER in its consideration of the revenue requirements of the TNSPs.

The new arrangements will be informed by the congestion management scheme (under review by the AEMC) and efficient behaviour will be rewarded through the service incentive regime (under development by the AER). The merits of aligning transmission revenue determination timetables will be considered.

COAG has also agreed to a revised network planning and consultation process, replacing the current 'Regulatory Test'. The AEMC will be tasked with advising on amalgamating the Regulatory Test criteria of reliability and market benefits and broadening the latter's definition to include national market benefits. This will allow proposed transmission projects to be assessed against meeting both local reliability standards and their ability to maximise benefits to the national market. This is intended to recognise the broader national benefits which may be achievable from investment opportunities whilst encouraging and ensuring those justified solely on reliability grounds are delivered in an efficient and timely manner.

COAG further agreed that, under the new transmission planning arrangements:

- accountability for jurisdictional transmission 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;

- 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.

COAG has also committed to reviewing the effectiveness of these arrangements after five years of operation, with a view to making further improvements if necessary.

ERIG has also recommended that the AEMC Reliability Panel review jurisdictional transmission reliability standards and develop a consistent national framework. COAG agreed that this review should be progressed, but with appropriate caution noting the different physical characteristics of the network, existing regulatory treatments in balancing reliability and costs to consumers, and that these standards underpin security of supply.

In summary, COAG has asked the MCE to:

- task the AEMC, in consultation with the AER, NEMMCO and other stakeholders, to develop a detailed implementation plan for the establishment of a national transmission planning function within the NEMO, including proposed amendments to the relevant Law and Rules for decision by the MCE;
- include the following features in the direction to the AEMC:
  - development of a strategic NTNDP, with annual updates;
  - amalgamating the Regulatory Test criteria of reliability and market benefits and broadening the latter's definition to include national market benefits;
  - consideration of alignment of regulatory periods to further reinforce the national character of the planning arrangements;
  - where possible, the new regime must at a minimum be no slower than the present time taken to gain regulatory approval for transmission investment;
  - provision for urgent and unforeseen investment to be made, when required;
  - the NTNDP will not be binding on transmission companies;
  - the AER will have regard to the NTNDP when making revenue determinations (the NTNDP will not bind the AER in its consideration of the revenue requirements of TNSPs);
  - preservation of the jurisdictional roles of VENCorp and ESIPC; and
  - leaves accountability for transmission investment, operation and performance with transmission service providers.
- task the AEMC with reviewing transmission network reliability standards with a view to developing a consistent national framework for network security and reliability, for MCE decision.

8. Timeline

Reform	Date
1. Governance • MCE to provide annual progress reports to COAG on energy market reforms • COAG Reform Council annual report to include energy market reform	Dec 2007
2. National Energy Market Operator • MCE to develop detailed implementation plan • Establish National Energy Market Operator	Dec 2007 June 2009
3. Transmission Planning and Regulation • MCE to task the AEMC with development of new regime	June 2007

• AEMC to advise MCE on new regime, including proposed Laws and Rules • AEMC to report on national framework for network reliability standards • Establish National Transmission Planner and revised transmission regulation within NEMO	June 2008 Sept 2008 June 2009
4. Energy Rules and Derogations • MCE to review all remaining derogations • MCE to report to COAG on remaining derogations	 June 2008 Dec 2008
5. Retail Price Regulation • MCE to review energy CSO mechanisms	 June 2008
6. Financial Markets • AEMC, NEMMCO, ASX to develop options to integrate markets • AEMC, AER and NEMMCO to address network support contracts, wholesale trading and settlement residue auctions	 Dec 2007 June 2008
7. Western Australia and Northern Territory • WA and NT to monitor the outcome of local and national energy market developments on an ongoing basis and consider the adoption of national institutions	 Ongoing