ELECTRICITY TRANSMISSION NETWORK owners forum

21 December 2007

Dr John Tamblyn
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Dear John,

THE NATIONAL TRANSMISSION PLANNING ARRANGEMENTS - ISSUES PAPER

The Electricity Transmission Network Owners Forum (ETNOF) appreciates the opportunity to provide comment on the Commission's National Transmission Planning Arrangements – Issues Paper.

ETNOF's submission to the Issues Paper is attached.

If you have any questions or require clarification of any aspect regarding this submission please contact me on (07) 3860 2143.

Yours sincerely,

Merryn York.

Merryn York
CONVENOR
REGULATORY MANAGERS GROUP

Attach.

TransGrid ElectraNet Powerlink TRANSEND SP AusNet

ELECTRICITY TRANSMISSION NETWORK owners

National Transmission Planning Arrangements

Response to AEMC Issues Paper

21 December, 2007

TransGrid ElectraNet electricity transmission Powerlink Queensland TRANSEND SP AusNet A member of Singapore Power Group

ELECTRICITY TRANSMISSION NETWORK owners

National Transmission Planning Arrangements

Response to AEMC Issues Paper

This submission presents the Electricity Transmission Network Owners Forum (ETNOF) response to the Australian Energy Market Commission's (Commission) Issues Paper on National Transmission Planning Arrangements.

The Commission has been directed by the Ministerial Council for Energy (MCE) to conduct a review into the development of a detailed implementation plan for new national electricity transmission planning arrangements. The review must provide for the establishment of a National Transmission Planner (NTP) to be located in the Australian Energy Market Operator (AEMO) which is also to be established. The NTP will be required to publish an annual National Transmission Network Development Plan (NTNDP). The Commission has also been charged with developing a new network planning and consultation process to replace the current Regulatory Test as a part of the review.

The Commission has expressly recognised that the proposed arrangements for the NTNDP and NTP need to meet the requirements set out by the Council of Australian Governments (COAG).

Submission Overview

This submission is made up of four parts as follows:

- Part A: ETNOF's model for the NTNDP and the implications this has for the functions of the NTP;
- Part B: ETNOF's proposal for revision of the network planning and consultation process to achieve a 'Regulatory Investment Test';
- Part C: An assessment of proposed NTNDP models against COAG's requirements for this function; and
- Part D: Individual responses to each of the issues raised in the Commission's Issues Paper.

Part A: ETNOF's Model for the NTNDP and the Implications of This Model

Summary of the Proposed Content of the NTNDP

An NTNDP developed in accordance with COAG's decision[1], as outlined in this submission, will enhance the value of transmission planning activities within the National Electricity Market (NEM). In summary, this submission proposes an NTNDP that will:

- provide a description of potentially worthwhile NEM transmission service developments between 5 and 15 (possibly 20) years into the future to inform investment decision making in the nearer term (5 years) by TNSPs and NEM generation businesses. Development options should be identified for each of a range of thoroughly researched plausible demand growth and generation sourcing scenarios;

- focus on longer term developments that have national significance being those which are sensitive to the location and type of future generation thereby affecting competitive market investment decisions and are significant in the generation scenarios (particularly developments where interstate or high volume transfers are integral to the scenario and affect the planning activities of more than one TNSP);

- develop scenarios associated with different economic outlooks, technology developments and relevant government policy themes and their consequential impacts on likely demand growth and generation sourcing. For example, economic transmission options that would support different climate change policy responses could be identified;

- incorporate analysis of nationally significant transmission development options at a level appropriate to providing credible, strategic guidance to investors and policy makers. This analysis would be expected to identify future development options that may have economic and/or policy merit; and

- include the data, assumptions and analysis which underpin the NTNDP. This information would form a national database which is available to TNSPs to facilitate consistent analyses for network planning.

COAG requires that the Interregional Planning Committee (IRPC) functions and Annual National Transmission Statement (ANTS) be replaced by the new national planning arrangements. Accordingly, the NTNDP would also be expected to be informed by these activities and include information currently published each year in the ANTS.

[1] COAG Response to the Final Report of the Energy Reform Implementation Group, as contained in the COAG Communique of 3 April 2007.

An important aspect of COAG's decision is the relationship between the NTNDP and other regulatory processes, such as implementation of the Regulatory Investment Test and economic regulation of TNSPs by the AER. The NTNDP is intended to inform these processes while leaving investment decision and accountability for transmission service outcomes with the TNSPs. Similarly, the NTNDP is intended to inform the AER's revenue setting role, recognising that the AER's revenue decisions must be formulated on the basis of a broad range of considerations set out in the National Electricity Rules (NER). To this end this submission proposes the following.

- The NTP would not carry out the Regulatory Investment Test (RIT) process per se, which is consistent with COAG's requirements for clear accountability for investment decision making to remain with TNSPs. However, development options set out in the NTNDP would inform interested parties, including TNSPs, of possible transmission network developments, particularly where a development option is primarily driven by net (national) market benefits.

- Consistent with COAG requirements, transmission development options identified within (or omitted from) the NTNDP would not bind TNSPs to implement those options. In addition, TNSPs could (and, if necessary, must) pursue options not identified within the NTNDP. This follows from accountability for investment decisions and reliability outcomes remaining with TNSPs, as per COAG's decision.

- The NTNDP would also inform the AER's five year revenue cap reviews. However, consistent with COAG's requirements, TNSPs would not be bound by the NTNDP and the AER would not be bound to limit its decisions solely to proposals included in the NTNDP. Rather, TNSPs could seek recognition of any proposed investment option as part of the AER's revenue cap regulation process on the basis of current assessment criteria related to whether the investment option is an efficient and prudent way for the TNSP to meet its mandated obligations.

Nothing in ETNOF's proposed NTNDP content or process would add delays to the development timelines already being achieved by TNSPs. This is also a key requirement of COAG's decision.

ETNOF considers that by adopting the outlook, content and analysis above, the new national transmission planning arrangements (particularly the NTNDP) will deliver a more strategic and nationally coordinated approach to transmission network development. This approach would also provide consolidated information to guide investors, with the aim of contributing to the optimisation of investment between transmission and generation across the power system. Identification of longer term generation developments for scenarios based on a range of plausible 'future worlds', and the analysis of the economics of nationally significant transmission development for those scenarios is the key element which will deliver COAG's desired outcomes.

A1. The NTNDP as Part of the Overall Planning Regime

ETNOF agrees with the Commission that network planning is not a single task but is a process.[2] ETNOF endorses the strategic objective of the NTNDP to enhance the national focus of that planning process noting that the NTNDP has been described by COAG as 'strategic', having a long-term outlook (a minimum of 10 years) and one which necessarily implies a high level view consistent with a national focus.

Therefore, any plan to implement the NTP and NTNDP must establish the role for the NTP without duplicating the role of TNSPs, cutting across TNSP accountabilities, or adding to existing transmission development timelines. It must also recognise these distinct responsibilities within the overall planning process: a mutually exclusive but *symbiotic* set of responsibilities.

To make an informed assessment of the future demand for transmission services, it is necessary to identify the plausible scenarios for the likely future location and size of demand and generation. TNSPs must do this in considerable detail to make individual investment decisions, and provide a medium term view in their respective annual planning reviews, as does NEMMCO in developing the Annual National Transmission Planning Statement (ANTS). These assessments include extrapolations of current trends over the medium term informed by forecasts of factors such as economic growth – in the language of strategic analysis, they are sensitivities on a largely business-as-usual scenario, with some allowance for observable trends. ETNOF considers this would be enhanced by annual assessments from a national perspective over a longer time horizon, which would include distinct scenarios formed from internally consistent 'future world' views incorporating 'step changes' in generation mix and location.

ETNOF considers there would be considerable benefit to be gained by fully specifying credible alternative 'future worlds' or scenarios as input to the development of a NTNDP. This would be a significant undertaking which, because it involves a much longer timeframe and is not part of any current transmission or energy planning processes. The construction of scenarios is discussed further in section A3.

ETNOF also submits that the term 'national' should be interpreted in this context to relate to matters which may affect delivery of the Market Objective across the NEM as a whole, rather than in just one part or region. Transmission requirements that are materially sensitive to the future location of generation are considered to be the key indicator of national impact because of the effect on the (national) energy market. Generation investment in one part of the network may reduce (not necessarily on a one for one basis) the need for generation investment elsewhere. This, in turn, is reflected in the demand for transmission along corridors, some of which may extend beyond a single NEM jurisdiction or the service area of a single major NEM TNSP.

[2] Issues Paper, p23.

Importantly, where transmission is not likely to be affected by generation decisions or actions by other TNSPs (for example, because it is predominantly serving demand in local and regional load centres), the transmission would be neither nationally significant nor strategic for the purposes of the NTNDP. In these cases, the NTNDP should simply note the additional load supplying transmission as a matter for the relevant TNSP to attend to in due course.

The timeframe covered by the NTNDP should start no earlier than 5 years ahead and have an outlook of at least 15 or possibly 20 years. The outlook period should build on where TNSP Annual Planning Reports[3] end and extend far enough into the typical lifecycle of network investments and long enough to enable different plausible scenarios of the future to provide meaningful information.

In summary, ETNOF considers that the overall transmission planning process in the NEM can be enhanced consistent with COAG's decision with the addition of a well targeted and focussed NTNDP, which avoids overlap with existing TNSP planning activities. The NTNDP should present a series of scenario based strategic, nationally focussed, assessments of possible demands for transmission services under a series of comprehensive, plausible, scenarios of future conditions in the NEM.

A2. Elements of the NTNDP

The NEM transmission planning process will be enhanced by an NTNDP that provides a long-term strategic view of possible demands for transmission developments under a number of different plausible scenarios. ETNOF considers that the NTNDP should present a 'big picture' view, in keeping with its strategic role in the overall planning process. Each scenario should also comprise three primary elements.

1) *Map* - A 'map' showing the demand for major transmission service capability across the NEM and across time. The map should focus on network requirements that are:

   - sensitive to the location and type of future generation, and hence affect competitive market investment decisions; and

   - significant in the scenario, particularly where interstate or high volume transfers are integral to the scenario and affect the planning activities of more than one TNSP.

   The map should allow readers to readily identify required changes for transmission transfer capability. For example, an increase of at least 250MW required between Qld and NSW in 2014–2016; an increase in capacity out of Latrobe Valley of at least 300MW by 2011-2013; etc. These 'maps' could be presented at five yearly intervals. The projections of demand for transmission services should be based on high level analysis and identify notional corridors for power flow between geographical areas of generation surplus and supply shortfall - these would not be detailed network loadflow results, nor would they be

[3] NER Clause 5.6.2A requires TNSPs to report on forecast network constraints 1, 3 and 5 years ahead and provide possible solutions to those limitations.

able to be (mis)interpreted as definitive geographical alignments for future easements. As different scenarios will result in different generation locations and types, there is unlikely to be a common set of nationally significant transmission corridors across the different scenarios. These nationally significant corridors would replace the current concept of 'flow paths'.

2) *Rationale and specification for each scenario and associated data.*

This section of the plan should specify the set of scenarios employed in the NTNDP. Consistent with responsibility for investment decisions remaining with TNSPs, the scenarios should form non-binding guidance to TNSPs[4] and other stakeholders. Publication of this data would extend the current practice of the Statement of Opportunities and Annual National Transmission Statement.

At a minimum, the data should include:

- demand forecasts which take account of key drivers (ie. CPI, GDP, price elasticity (likely to be important for Greenhouse gas schemes)); and
- projections of generation technologies such as:
    - generation type (eg. combined cycle gas turbine, super critical coal, ultra-super-critical coal, carbon dioxide capture and storage (CCS) and renewables including wind, geothermal and biomass);
    - development timeframes;
    - fuel options, including location and cost (eg. gas fields, gas pipelines, coal seam methane, coal, other);
    - resource limitations (eg. CCS sites, wind sites and wind system constraints/policies);
    - policy projections (eg. to facilitate demand side or building energy efficiency;
    - the nature of distributed generation; and
    - generation technology costs (ie. capex, opex and cost learning curves).

3) *Analysis that supports each 'map'.*

Analysis to support the network flows which underpin the demand for transmission services in each 'map' should be similar to that employed for a commercial, pre-feasibility study.

At a minimum, the analysis should be done on the same economic basis as the applicable Regulatory Investment Test (undertaken in high level broad terms).

[4] To ensure that accountability for transmission investment decisions is not diminished, TNSPs must remain responsible for the final choice of scenarios to be modelled in detailed evaluations for investment decisions, appropriate to meet their obligations under the NER and jurisdictional instruments.

Such analysis should be sufficient to identify whether options fit into one of three categories – likely to be economic, marginal and unlikely to be economic.

A second analysis could also be carried out which includes a full general economic cost benefit analysis or other criteria at the discretion of the NTP.

A3. Scenarios

ETNOF's proposal, presented here, places considerable emphasis on the determination of plausible scenarios. ETNOF considers a scenario approach is both practical and appropriate given the level of uncertainty associated with:

- the future location of generation and level of demand in the long-term;
- the number of different economic, technical and policy factors which impact upon electricity transmission requirements; and
- among other things, these include population growth, generation technologies, fuel sources and energy intensity. All of these factors can change significantly over a longer time horizon.

The use of scenario-based planning and assessment in the NTNDP is a natural extension of the role of scenario planning already embodied in the NEM transmission planning regime. Different levels of scenario analysis are currently used to account for different future outcomes over the longer term in TNSP investment assessments, TNSP revenue proposals and NEMMCO analysis in the Statement of Opportunities.

ETNOF believes that the design of scenarios on which the NTNDP is based should be subject to consultation with stakeholders. Key elements of some scenarios will be determined by government policy decisions (such as the form of emissions trading scheme), the availability as well as licensing (or prohibition) of particular generation technologies, or availability of water for power station use. External factors such as international economic conditions may also shape other scenarios. To illustrate, scenarios might be constructed around:

- a government policy to aggressively facilitate energy efficiency requirements that might only be politically acceptable if good economic conditions continued;
- carbon policies where Australia acts unilaterally (and, say, energy intensive industries move off-shore), or where international agreements protect these industries, leading to major changes in generation merit order, which could reshape the future development of the transmission system; and
- technologies of particular relevance to transmission developments could assume a major shift to distributed generation or new renewable energy sources such as wind and geothermal.

In developing scenarios, the NTP could also work with other authorities who have previously developed similar sets of scenarios. For example, the Energy Future Forum, whose work was prepared by a cross section of the electricity industry[5] and published in December 2006 under the auspices of the CSIRO.

A4. Types of Network Developments to be Identified

ETNOF's view is that the NTNDP will necessarily have to consider the capacity of existing and future transmission corridors. Such corridors should be limited to those which are of national significance. Clearly these will need to be identified on a case by case basis for each scenario considered, and should be limited to existing and potential corridors which either presently, or over the life of the NTNDP, are expected to frequently carry material flows and thereby provide enduring benefits to the national economy.

It is not intended that these corridors be defined to the level of geographical precision required for, say determining the alignment of a transmission line easement.

ETNOF believes that major network developments noted in the NTNDP should include:

- notional, nationally significant transmission corridors where none currently exist – as part of the economic development of major new generation centres or to bypass expected congestion points;
- existing corridors that may require capacity expansion; and
- possible voltage levels and technology choices (eg. HVAC versus HVDC) for new or upgraded corridors, bearing in mind expected ultimate capacity requirements.

In developing any potential solutions for inclusion in the NTNDP, the practicality of any such developments must be taken into account. This is to ensure that the NTP, by way of the NTNDP, does not propose clearly impractical developments - such as a new transmission corridor which traverses sensitive national park, or an area designated for urban development. It will also be necessary for any such public information to be high level and general in nature, to avoid premature community reaction to plans which may, in some cases, not eventuate.

National Transmission Flow Paths

In its response to the Commission's Scoping Paper, ETNOF noted the need to revisit what currently constitutes 'major national flow paths' given COAG's view that the NTNDP should be strategic in focus and, in the interests of efficiency. In the context of a strategic NTNDP, it is clear that some of the flow paths currently (somewhat subjectively) defined by NEMMCO as 'major national flow paths' simply do not fit because they are clearly NOT national in nature, eg. a flow path between central and north Queensland.

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5 Available online from http://www.csiro.au/resources/pfnd.html.

Consistent with its proposed approach above, ETNOF considers that an appropriate basis upon which to develop a new definition of 'national flow paths' is to consider notional corridors where the required level of transmission service is:

- sensitive to the future location and type of generation, and hence affect competitive market investment decisions; and
- significant in the context of the possible generation development outlooks, particularly where interstate or high volume transfers are integral to the scenario and affect the planning activities of more than one TNSP.

A5. The NTNDP and Transmission Regulatory Processes

An important aspect of COAG's decision is the relationship between the NTNDP and other regulatory processes such as the implementation of the Regulatory Investment Test, and the economic regulation of TNSPs by the AER. In essence, and in accordance with COAG's requirements, the NTNDP is intended to inform these processes while leaving clear accountability for investment decisions and accountability for transmission service outcomes with TNSPs. Likewise, the NTNDP is intended to inform the revenue setting role of the AER, recognising that the AER's revenue decisions must be formulated on the basis of a broad range of considerations as set out in Chapter 6A of the NER.

COAG's decision also requires TNSPs to continue planning and performing investment analyses of local and regional networks. It should be noted that, in accordance with the Rules, to identify the most efficient network development options, planning and investment decision making at this level is often carried out in close cooperation with DNSPs, including joint application of Regulatory Test evaluations and Rules consultation processes.

Development options identified in the NTNDP would inform interested parties, including TNSPs, of possible transmission network development outcomes, particularly where a development option is primarily driven by net (national) market benefits. Consistent with COAG's requirements, the transmission development options identified within (or omitted from) the NTNDP would not bind TNSPs to implement (or ignore) those options. The NTP would not carry out the Regulatory Investment Test (RIT) process per se. This responsibility links directly to investment decisions and thus remains with TNSPs. Suggestions which involve the NTP performing 'part' of those two processes would blur accountabilities and contravene COAG's requirement for accountability to remain with TNSPs. In addition, TNSPs could (and are legally obliged to) consider, and if necessary, pursue investment in options that are not identified in the NTNDP. Examples of this include local and regional investments developed jointly with DNSPs, or unforeseen but efficient options that are confirmed by evaluation under the Regulatory Investment Test consultation process, such as demand side response or network support generation.

The NTNDP would also inform the AER's five year revenue cap determinations. However, consistent with COAG's requirements, TNSPs would not be bound by the NTNDP and the AER would not be bound to base its revenue decisions solely on proposals included in the NTNDP. Rather, TNSPs could seek recognition of any proposed investment option as part of the AER's revenue cap regulation process on the basis of current assessment criteria related to whether the investment option is an efficient and prudent way to meet the TNSP's obligations.

A6. Role of the National Transmission Planner

Having outlined its view of what the NTNDP should contain, and the framework within which it should be developed, ETNOF considers that the role of the National Transmission Planner should be to:

- develop scenarios and key input parameters such as:
    - demand; and
    - generation technologies (eg. performance and cost);
- develop NEM-wide, broad, plausible scenarios for generation development to meet NEM supply/demand balance and to identify notional, national transmission corridor capability requirements for each scenario;
- identify notional, transmission corridor developments of national significance. In particular, the sequence of possible strategic developments and the anticipated broad timing of these which efficiently satisfy the scenario/s that underpin them;
- publish the information identified above as part of the NTNDP, with a 5 to 15/20 year outlook;
- provide an annual update of the NTNDP, which also takes account of the results contained in each TNSP's Annual Planning Report; and
- include in the NTNDP, the data, assumptions and analysis which underpin the NTNDP.

Consistent with the boundaries established by COAG for the NTP and NTNDP to be strategic in perspective, these are important functions which focus on matters of national significance. Contrary to this view, the AER has sought to involve the NTP in matters of detail[6], including assessment of the merits of individual augmentation projects proposed by TNSPs as part of their revenue reset proposals. The National Electricity Law and Rules clearly provide that it is the role of the AER to assess the merits of revenue proposals and individual projects contained therein consistent with the objectives, evidentiary matters and processes established by the Commission. While the NTNDP may provide input to the AER's considerations on strategic matters, the character of the plan is not intended and should not be construed as a surrogate for the AER's own detailed assessment as to the efficiency and reasonableness of a TNSP's expenditure proposals.

[6] Issues Paper, p22.

Among other things, an important element in the implementation of the National Transmission Planning function is that there is no duplication of effort between the NTP and TNSPs. The issue of duplication of the roles between the NTP and TNSPs was highlighted in the majority of submissions in response to the Commission's Scoping Paper, as well as concerns about the NTP impinging upon TNSPs' accountability. These accountabilities extend beyond the need to provide reliable transmission services and also incorporate commercial obligations to transmission customers and shareholders. ETNOF considers that COAG clearly understood the significance and primacy of these legal and service obligation issues, as evidenced by its commitment that accountability for jurisdictional transmission investment, operation and performance remain with TNSPs.

To ensure there is clear separation between the functions of the NTP (discussed above) and TNSPs, the role of TNSPs is therefore to:

- conduct detailed planning and economic/engineering analysis of potential options to address identified network needs which:
    - efficiently satisfy reliability and other legislative obligations;
    - take account of the broader, strategic outlook of the NTNDP, including identified national transmission corridor developments;
- make investment decisions. This requires that TNSPs:
    - make provision for prudent and efficient capital (and operating) expenditure in their respective Revenue Proposals;
    - conduct the Regulatory Test analysis and related Rules consultations for all investments required to meet its mandated and other obligations;
    - make other transmission network investment decisions as required; and
- prepare and publish the Annual Planning Report, which reflects a short to medium term view of network development (1 to 5 plus years).

Consequently, there will be a need for a relatively high level of interaction between TNSPs and the NTP. For example:

- a starting point for the NTP's annual update of the NTNDP will be the configuration of the network anticipated by TNSPs at the start of the NTNDP planning horizon. ETNOF has proposed that this be 5 years ahead.
- TNSPs (as well as other interested parties) will be able to make use of the scenarios and data analysis assumptions documented in the NTNDP.

Therefore, governance arrangements for the NTP should provide for an effective working relationship between TNSPs and the NTP, but at the same time, preserve their independence.

A7. Load Serving Developments by TNSPs

Given that network developments which are primarily 'load serving' are often largely independent of the location of major generation and, in particular, developments by other TNSPs, only very broad indications of such developments need to be included in the NTNDP. Such developments are often not of national significance. Load serving parts of the network will be developed by relevant TNSPs in the normal course of business to meet reliability and performance obligations. These will necessarily be addressed in TNSP Annual Planning Reports, and other consultation documents required under the Rules.

Demand Side and Embedded Generation Alternatives to Transmission Investment

The current demand forecasting process under the NER provides for demand side management and embedded generation to be forecast and specifically accounted for in determining the requirements to maintain reliability of supply standards. In addition, TNSPs are currently required to identify and consider non-network alternatives to specific transmission investment proposals under the economic evaluation of options under the Regulatory Test and as part of the NER consultation process for investment. TNSPs are also required to provide information on forecast constraints in their respective Annual Planning Reports to inform potential non-network solution providers and to allow advance notice for such alternatives to be developed.

ETNOF considers that the mechanism to account for non-network solutions in a strategic timeframe need to be incorporated into the specification of the NTNDP. Properly developed scenarios should consider the level of demand side and embedded generation that is realistically expected to emerge as a matter of course within those scenarios. Consultation on these assumptions would allow for stakeholder response. It will be important for the NTNDP to neither overstate nor understate the likely range of demand side response.

Part B: Revision of the Network Planning and Consultation Process

This Part of ETNOF's submission addresses the options put forward by the Commission in relation to the amalgamation of the two limbs of the current Regulatory Test within the Commission's new Regulatory Investment Test (RIT).

In its Issues Paper, the Commission sets out three options:[7]

Option 1: Full cost benefit approach;

Option 2: Least-cost approach; and

Option 3: Combined criteria approach.

The Commission notes in its Issues Paper that no submissions supported the implementation of Option 2. As a consequence, the Commission's discussion in the Issues Paper focuses on Options 1 and 3.

ETNOF strongly supports the implementation of Option 3. The reasons for this include:

- Option 1 is inconsistent with mandatory reliability standards based on a redundancy framework applying to TNSPs. This approach is widely used and must be catered for in the current revision of the network planning and consultation process;

- Option 1 is inconsistent with the need for TNSPs to undertake joint planning and Regulatory Test evaluations with distributors who base their planning on deterministic (redundancy based) reliability criteria;

- Option 1 would significantly increase the complexity of the analysis required for all RIT applications and would result in a lengthening of the time taken to gain regulatory approval for investments driven by reliability concerns. Such an outcome indicates that Option 1 is inconsistent with COAG's directives in relation to the review, specifically in relation to adding to existing development timelines;

- Under Option 3, a 'fit for purpose' approach to RIT evaluations will allow approval timeframes to be maintained in accordance with COAG's directive.

Each of these points is discussed in turn.

B1. Inconsistency with Reliability Framework

Currently, reliability standards are established (and periodically reviewed) by the jurisdictions[8]. As this situation is likely to continue, the revised network planning and consultation process needs to work with the current arrangements for reliability standards. In future this will occur on the basis of the framework determined as a

7 AEMC, *National Transmission Planning Arrangements: Issues Paper*, 9 November 2007, p. 38.
8 Or a body appointed by the jurisdiction.

result of the Reliability Panel's imminent review. There is therefore a critical interaction between these two reviews. The Commission recognised this interaction in its earlier Scoping Paper[9]. Notwithstanding this, the suitability or otherwise of Option 1 does not appear to have been adequately considered in the Issues Paper.

A review of jurisdictional standards is generally carried out on the basis of economic considerations[10]. Such an approach provides a robust and effective basis for determining appropriate reliability standards and ensures that those standards are linked to economic considerations. This approach also has important advantages which includes transparency of application and clarity in the accountability of TNSPs for provision of service outcomes.

Given the above approach for determining reliability standards in each jurisdiction, and the current application of mandatory standards to TNSPs, it would be wholly inappropriate to adopt Option 1 as the means for amalgamating the two limbs of the Regulatory Test. To do so would override the separate, jurisdictional process for determining appropriate reliability standards. Option 1 would require a TNSP to assess the reliability that would result from a proposed augmentation at the time of each RIT application and to, in effect, select a reliability standard in relation to each augmentation that the TNSP considers to be justified on the grounds of the cost benefit analysis.

Option 1 therefore undermines transparency in relation to the reliability standard applying in a jurisdiction and conflicts with the process currently conducted by the Reliability Panel.

Under Option 1, the accountability of TNSPs in relation to reliability outcomes is also unclear, given that reliability would in effect be the outworking of the RIT analysis. Such accountability is a fundamental issue that would need to be clearly addressed by the Commission in considering the adoption of Option 1.

B2. Joint Planning with DNSPs

A further key issue is the need to ensure compatibility between the approach taken to amalgamating the reliability and market benefits limbs of the Regulatory Test and joint planning between TNSPs and distribution network service providers (DNSPs).

Irrespective of the arrangements to enhance coordination of national transmission planning, augmentation and development of local and regional electricity networks will continue to occur through joint planning and investment analysis between TNSPs and DNSPs. By way of example, joint planning for serving load around the border areas of Gold Coast/Tweed and Goondiwindi involves TNSPs and DNSPs from both regions. Similarly, a joint Regulatory Test evaluation has recently commenced in the Newcastle load area and since 2003 TransGrid has undertaken 15 New Large Transmission Network Asset consultations, of which 11 were published jointly with a

[9] AEMC, *National Transmission Planning Arrangements: Scoping Paper*, August 2007, p. 14: 'Consideration of this issue will need to be closely aligned with the review into transmission reliability standards, to be conducted by the Reliability Panel.'

[10] Refer ESCOSA (2006), Review of the Reliability Standards Specified in Clause 2.2.2 of the Electricity Transmission Code, Final Decision, September.

DNSP. The National Electricity Rules require such joint planning,[11] which ensures that the capacity of the transmission network is sufficient for the purposes of conveying power to the distribution network and, ultimately, to end-use businesses and customers. Joint planning also ensures the most efficient outcomes for customers (consistent with the Market Objective) and this is often a combination of TNSP and DNSP augmentations.

NEM DNSPs are required to plan their networks to meet deterministic planning standards set exogenously, usually by a relevant jurisdictional body. In undertaking joint planning, DNSPs require certainty that the level of reliability delivered by the transmission network will be sufficient to enable the DNSPs to meet these mandated reliability standards.

Given this situation, it is clear that Option 1 *is not compatible* with delivering the certainty that DNSPs require in relation to the level of reliability delivered by the transmission network. This is because under Option 1, the level of reliability is an uncertain, endogenous outworking of the cost benefit analysis, rather than a firm, transparent, exogenous standard to which DNSPs can plan. In addition, given that DNSPs are obliged to meet a deterministic standard, Option 1 is not compatible with the identification of a least-cost joint TNSP/DNSP solution, and would therefore result in a move away from the Market Objective.

ETNOF notes that the scope of the Reliability Panel's review regarding the framework for reliability standards does not include DNSP reliability standards. This is a significant issue in NEM jurisdictions where DNSPs own significant subtransmission assets, and where joint planning for least cost outcomes typically results in a combination of complementary TNSP/DNSP augmentations.

In contrast, Option 3 is compatible with joint planning requirements as it provides certainty as to the mandated level of reliability that will be delivered by the transmission network. As discussed above, under Option 3 the reliability standard is taken as an exogenous input into the RIT analysis, rather than being reduced to an outworking of that analysis.

Furthermore, given the frequent application of the Regulatory Investment Test to joint investment decisions, the form of the new Regulatory Investment Test must be capable of consistent application to transmission and distribution investments. As noted earlier, DNSPs require a Regulatory Investment Test which delivers pre-determined reliability standards. Option 3 is compatible with this requirement, whereas Option 1 is not. As such, Option 3 facilitates least cost joint outcomes, consistent with the Market Objective.

B3. Option 1 Increases the Complexity of All RIT Applications

The Commission notes that a key difference between Option 1 and Option 3 is that under Option 1, the level of reliability delivered by a proposed augmentation (and alternatives to that augmentation) is *explicitly valued* as part of the cost-benefit analysis. In contrast, under Option 3, the required level of reliability is determined by

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[11] NER, 5.6.2 (a1)-(c).

a separate, prior process and is then *taken as given* when conducting the RIT assessment.

Where an investment is primarily driven by reliability concerns, under Option 3 only those investments that meet (or exceed) the mandatory reliability standard are considered in the RIT assessment. As a general rule, any incremental improvement in reliability over and above the mandated standard would not be taken into account as part of the RIT assessment.

In contrast, under Option 1, the level of reliability provided by alternative options is itself included in the RIT analysis. Therefore, it follows that under Option 1, the level of reliability delivered by the augmentation need not be equal to the level of reliability determined by the body setting the standard – which suggests that the outworked standard may be above or below this standard.

Therefore, a key distinguishing feature between Options 1 and 3 is that Option 1 requires the level of reliability resulting from alternative augmentations (or non-network options) to be *explicitly valued* in relation to all RIT applications. In practice, this is likely to be achieved though estimating the expected level of unserved energy (USE) associated with an augmentation and then applying a value per MWh to this level of USE.

Estimating the USE expected to result from an augmentation for each and every project assessment is a significant network modelling task, involving the computation of load flows. Similarly, the value of per MWh for each expected level of unserved energy is highly variable across customer class, time of day, time of year and geography. This would therefore need to be assessed for each connection point, and then updated on a regular basis.

The increased complexity of the analysis under Option 1 for investments primarily driven by reliability considerations is explicitly recognised by the Commission.[12] In addition to the need to explicitly model changes in USE, Option 1 (as defined by the Commission) does not incorporate a materiality provision. This implies that all costs and benefits would need to be modelled for all RIT assessments, even where some of the benefits are not expected to be material.

The complexity of such an analysis not only consumes valuable, scarce, resources, but is less transparent and more open to disputation. Taken together, the prospect for delays in the conduct of Regulatory Investment Test consultations is assured in most cases and would be expected to be material. Such an outcome will clearly impact the overall timing of investment decision making and project delivery. As a consequence, ETNOF considers that Option 1 is inconsistent with COAG's directive that the new planning processes do not add delays to the current timelines for delivery of required investment.

B4. Option 3 Provides Practical Flexibility

The Commission has characterised Option 3 as something less than a 'full cost benefit analysis', in contrast to Option 1.

[12] AEMC, *National Transmission Planning Arrangements: Scoping Paper*, August 2007, p. 14.

ETNOF considers that Option 3 could be more appropriately characterised as a ‘fit for purpose’ cost benefit analysis. That is, Option 3 provides the practical flexibility for TNSPs to include or exclude certain elements of benefits, depending on whether those benefits are likely, in practical terms, to impact the outcome of the assessment. Such assessments of inclusion or exclusion would be considered by other parties through the consultation process resulting in a high level of transparency. Interested parties would be able to provide their own assessment of the elements of benefits thereby shaping the investment assessment through the consultation process.

In contrast to both Option 2 and the AER’s current Version 3 of the Regulatory Test, Option 3 allows TNSPs to incorporate benefits that result from the impact of an augmentation on the wider national electricity market (NEM), rather than the assessment being strictly limited to the direct costs of an option. As a result, RIT assessments under Option 3 for augmentations mainly driven by the need to meet a reliability standard could encompass consideration of (amongst other factors):

- the impact on overall network losses;
- the impact on generation investment elsewhere in the NEM (ie. potential generation deferral as the result of the augmentation); and
- the impact on generator dispatch costs.

However, in many cases, where investments are primarily driven by the need to meet a network reliability standard, there may be very few impacts of the augmentation on the wider operation of the NEM, ie. generation investment, generation dispatch and generation competition. Requiring the TNSP to value all of these benefits in detail as part of each and every RIT assessment (as is implied under Option 1) would result in increased resource costs and the extension of the timeframe required for the assessment, without any consequent change in the result of the RIT. Such an outcome leads to higher costs for little or no tangible benefits – this is a step away from the Market Objective. Further, ETNOF believes that Option 3 is required to meet COAG’s requirements for maintaining current investment delivery timeframes.

The Commission has queried how, under Option 3, TNSPs would be able to determine that certain aspects of benefits may not be material for a RIT application, without having first assessed the magnitude of the benefits. ETNOF recognises the Commission’s concern but believes that there are many circumstances in which a preliminary, high level assessment could demonstrate that the magnitude of a particular benefit is not material and would not change the ranking of options.

ETNOF recognises and accepts that the onus is on TNSPs under a ‘fit for purpose’ approach to credibly demonstrate as part of their RIT applications where benefits are not material. Interested parties are able to comment on and ultimately dispute the outcome of a RIT assessment if they are not convinced of the non-materiality of certain benefits in particular circumstances. It is therefore in TNSPs’ interests to ensure that the materiality question is fully addressed in the public consultation phase.

<u>Part C:</u> Assessing the Proposed NTNDP Models against COAG's Requirements

This Part of the submission assesses ETNOF's proposed model for the National Transmission Network Development Plan (NTNDP) and Network Transmission Planner (NTP), and the Commission's proposed models 1-4, against COAG's requirements. In summary, the analysis shows that both the Commission's Model 1 and ETNOF's proposed model (Model 5) meet the COAG requirements. It also suggests that Model 5, though similar to Model 1, scores most favourably under this assessment.

The table below summarises the 5 Models for the NTNDP and NTP together with the overall assessment of each Model against the COAG requirements for ease of reference in the subsequent analysis. The highlighted words in the table show features which are inconsistent with the COAG requirements. These inconsistencies are also identified in the notes before the table.

Feature	Model 1	Model 2	Model 3	Model 4	Model 5
1. CONTENT of PLAN					
a) Duration	20 years	10 years	As Model 2	10 years	A window starting at end of TNSP investment timeframes of up to around 5 years (noting projects by TNSPs) currently planned through to 15/20 years.
b) Scenarios	Wide – high and low probability scenarios	Narrow – focus on high probability scenarios	As Model 2	Highly focused – such that particular investment solutions can be identified	Wide – covering a range of demand and generation scenarios for each of a number of economic, technology, and policy contexts or themes. NTP scenarios to be published as (non binding) key items of industry information for planning by TNSPs and generators.
c) How is 'national' defined	As today – focus on NTFPs	Threshold impact on inter-regional flows	As Model 2	As Model 2	Covers major network development that is sensitive to location of generation and/or affects more than one jurisdiction or TNSP.
d) How specific?	Describes network capability and discusses conceptual augmentations identified by TNSPs	Describe network capability. Own modelling and identify possible projects	As Model 2 – plus identify solutions if task delegated to it by TNSP	Describe network capability. Identify options and best augmentation solutions	Sets out potentially worthwhile transmission service developments for each set of demand and generation scenarios. These are identified for each of 5, 10, 15, and, possibly 20, years into the future. Development options are assessed using relatively generic estimates of costs and benefits.
e) Range of assets?	Network augmentations	Network augmentations (and substitutes for network augmentations)	Network augmentations (and substitutes). Increase gas network and generation focus	Same as Model 3 plus planning of NCAS	Focus is on those transmission service developments that have material interaction with generation sourcing decisions and/or involve more than one jurisdiction or TNSP.

Feature	Model 1	Model 2	Model 3	Model 4	Model 5
2. NTP in RIT?	No involvement in application of regulatory test. NTP takes over IRPC advisory role on LRPP	NTP identifies and publishes information on national market benefits. NTP ability to exercise LRPP	As Model 2 – plus obligation to run Reg Test if delegated to it by TNSP	Has obligation to run Reg Test in respect of solutions it identifies. LRPP functions disappears	No. However, the NTNDP would provide data, maintained by the NTP, of estimates of non-transmission costs (such as fuel costs and generation development costs) and national benefit components which may inform TNSPs in their application of the RIT.
3. NTP Ancillary functions	Existing IRPC functions. Advice to AER role limited	Existing IRPC functions. Advice to AER role limited	As Model 2 plus developing common planning methodology and coordinates inter-regional investments	As Model 3 plus general advice to MCE and Publication of the SOO	Determine later but incorporate strategic functions and analysis of IRPC and ANTS into NTNDP.
4. Governance	Administrative body within AEMO reporting to (and appointed by) AEMO board	Defined (ring fenced) Board/Panel/Committee within the AEMO with independence	Defined Board/Panel/Committee or Defined Office Holder (ring fenced) within the AEMO with independence	Statutory authority or office holder – appointed through process specified in enabling legislation	Separate department within AEMO with transparent NTNDP development process and budget set in consultation with interested parties
Consistent with COAG decision?	**Yes**	**Somewhat** see Note 1 below	**No** see Note 2 below	**No** see Note 3 below	**Yes**

Note 1 (Option 2): paragraph 1(d) above would be inconsistent if the identification of possible projects becomes too detailed or prescriptive, as this would run counter to the COAG requirement of TNSPs remaining responsible for transmission investment.

Note 2 (Option 3): Item 3 of this model clearly encroaches on the COAG requirement that TNSPs remain responsible for transmission investment: Items 1(d) and 2 would be inconsistent without the caveat that the NTP would only undertake those actions if the TNSP delegated them to the NTP.

Paragraph 1 (e) will be inconsistent with the COAG requirement for a national "**transmission**" system plan, if it is intended that the plan include planning for the development of gas network & generation alongside planning for transmission development (as opposed to broadly considering any likely future gas and generation developments, as part of scenario forecasting for transmission planning purposes – this is an important distinction).

Note 3 (Option 4): Elements 1(b), 1(d), 2 and 3 of this model clearly encroach on the COAG requirement that TNSPs remain responsible for transmission investment.

Paragraph 1(e) will be inconsistent with COAG Requirements, as set in the above comments in Note 2 on Option 3.

Paragraph 4 is inconsistent with the COAG Requirement that the NTP be located within AEMO (section 3 of the COAG Decision) and that AEMOs functions are to encompass national transmission planning (section 2 of the COAG Decision).

Part D: Table of Responses to Specific Issues Raised by the Commission

The Commission is seeking the views of interested parties on a range of matters throughout its Issues Paper on the National Transmission Planning Arrangements. This attachment documents ETNOF's views on these matters in the order in which they are raised in the Issues Paper.

1.2 Commissions Approach to the Review
The Commission seeks views on:
• *Its proposed approach to the Review and its decision making criteria; and*
• *The materiality of the problems being addressed in this Review.*

Response:

ETNOF considers that the criteria proposed by the Commission appear to be reasonable and comprehensive. ETNOF concurs that the Commission's recommendations must be consistent with the direction provided by COAG[1], in particular, that:

- "accountability for transmission investment, operation and performance will remain with the 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; and
- the new regime must not reduce or adversely impact on the ability for urgent and unforeseen transmission investment to take place."

ETNOF notes that while the Commission may need to evaluate any trade-offs between different criteria objectively on the basis of evidence, it is essential that the COAG directions noted above are fully satisfied.

The Issues Paper notes (on page 5):

> "The problems that might be addressed through the creation of an NTP are discussed in the ERIG Final Report, and relate to issues of co-ordination, lack of information to support efficient investment and the perceived regional bias in criteria used to assess transmission investment options."

ETNOF concurs - as a matter of principle - that strengthening co-ordination and providing additional information will provide a means of further supporting efficient investment decision-making. COAG's response to the ERIG Final Report identifies this as the intended benefit of enhancing the planning process through establishing an NTP. COAG states that the enhanced process will provide guidance to investors to help optimise investment between transmission and generation across the power system. Therefore, within the national planning framework, the NTP's role will be strategic.

However, ETNOF does not consider there is any objective evidence to support the existence of regional bias nor evidence that transmission investment has been inefficiently low or misdirected. In fact, in its Draft Report on the Congestion Management Review (CMR) the Commission noted that outside of the Snowy region, there is limited evidence of material and persistent congestion in the NEM.

Given the substantial response embodied in the COAG decision through establishment of the NTP the strategic, longer term role proposed by ETNOF represents an outcome that is proportionate to the materiality of the matter to be addressed. This accords with the Commissions proportionality principles which ETNOF fully supports.

[1] COAG Response to the final report of the Energy Reform Implementation Group, as contained in the COAG Communique of 13 April 2007.

Chapter 3 Functions of the National Transmission Planner

3.1 Boundary between National and Local Planning

The Commission is interested in views on:

- *Whether the Commission is correct to assume that the scope of the NTP must be limited to a sub-set of 'national' planning issues if it is to be consistent with the MCE's direction;*
- *Whether a definition of 'national' that limits NTP scope to planning issues which relate to constraints which (materially) involve interconnector flows is practical and workable?*
- *Whether the current definition of National Transmission Flow Paths should be used in defining the scope of the NTP functions?*
- *What other practical options exist for clearly and unambiguously defining the scope of planning issues within the scope of the NTP.*

Response:

ETNOF considers that the requirements set out in the COAG decision provide for the establishment of an effective and fully functioning national planner.

The scope of the planning functions undertaken by the NTP and TNSPs must be consistent with their respective accountabilities, as determined by COAG. In this regard it is noted that:

- COAG determined that accountability for transmission investment, operation and performance will remain with the TNSPs;
- the NTNDP is to be non-binding on TNSPs and the AER; and
- COAG has described the NTNDP as "strategic", which implies that the NTNDP should present a "big picture" view of national planning issues, taking a longer term perspective.

ETNOF's submission has provided a detailed description of the respective roles of the NTP and TNSPs, including the scope and content of the NTNDP. Essentially, the NTP should focus on national network developments which ETNOF considers are those that are:

- sensitive to the location and type of future generation and hence affect competitive market investment decisions; and
- are significant in the generation scenarios, in particular where interstate or high volume transfers are integral to the scenario and affect the planning activities of more than one TNSP.

Therefore, the primary purpose of the NTNDP should be to provide a high level, long-term, scenario-based national perspective of possible power system developments and look forward from five to twenty years. This "big picture" outlook should identify major required increases in nationally significant transmission corridors and an indication of likely timing. These nationally significant transmission corridors replace the current concept of Flow Paths. Such an NTNDP would provide useful information to inform generation investment decisions (particularly locational) within the NEM, as well as information regarding potentially worthwhile transmission service developments.

Logically, by taking a strategic and national perspective, the NTP should only focus on a subset[2] of all transmission planning matters. It also follows that TNSPs must retain responsibility for short to medium term planning, whilst taking account of the findings of the NTNDP. ETNOF does not consider that there is any case for significant change to the roles and responsibilities of TNSPs. It should also be reiterated that duplication of roles between the NTP and TNSPs must be avoided.

Irrespective of the arrangements to enhance coordination of national planning, augmentation and development of local and regional electricity networks will continue to occur through joint planning and investment analysis between TNSPs and DNSPs. By way of example, the joint planning around the border areas of Gold Coast/Tweed and Goondiwindi involves the TNSPs and DNSPs from both regions. Similarly, a joint Regulatory Test evaluation has recently commenced in the Newcastle load area and since 2003 TransGrid has undertaken 15 New Large Transmission Network Asset consultations, of which 11 were published jointly with a DNSP. The National Electricity Rules require such joint planning,[3] which ensures that the capacity of the transmission network is sufficient for the purposes of conveying power to the distribution network and, ultimately, to end-use businesses and customers. The joint planning also ensures the most efficient outcome for customers (consistent with the Market Objective) and this is often a combination of TNSP and DNSP augmentations.

The existing arrangements for joint planning and investment work well. Establishment of the national planning arrangements must not detract from this.

3.2 Range of Scenarios and Level of Detail in the National Plan

The Commission seeks views on:

- *What range of scenarios should be required to be considered within the NTNDP?*
- *What level of detail should the NTNDP include in relation to options for, or solutions to, planning issues within its scope?*
- *In what specific ways might the NTP add value through greater involvement in the planning process, and how material would this added value be?*

Response:

A scenario approach is considered to be practical and appropriate given the level of uncertainty associated with the future location of generation and level of demand in the long-term and the number of different economic, technical and policy factors which impact upon electricity transmission requirements.

The design of scenarios on which the NTNDP is based should be subject to consultation with stakeholders. Key elements of some scenarios will be determined by government policy decisions such as the form of an emission trading scheme, the availability as well as licensing (or prohibition) of particular generation technologies, or availability of water for power station use. External factors such as international economic conditions may shape other scenarios. To illustrate, scenarios might be constructed around:

- a government policy to aggressively facilitate energy efficiency requirements that might only be politically acceptable if favourable economic conditions continued;

[2] The Commission requested views on whether the scope of the NTP must be limited to a sub-set of **national** planning issues. This wording is somewhat confusing. ETNOF considers it must be limited to a subset of **all** planning issues and should be focussed on issues of national significance.

[3] NER, 5.6.2 (a1)-(c).

- carbon policies where Australia acts unilaterally (and, say, energy intensive industries move off-shore), or where international agreements protect these industries, leading to major changes in generation merit order, which could reshape the future development of the transmission grid; and
- technology based scenarios of particular relevance to transmission developments could assume a major shift to distributed generation, or new renewable energy sources such as wind and geothermal.

In developing scenarios, the NTP could work with other bodies which have previously developed similar sets of scenarios, eg. the Energy Future Forum.

The analysis of options undertaken by the NTP and included in the NTNDP should allow readers to identify demand for transmission transfer capability across the NEM across time. For example, increase of at least 250 MW required between Queensland and NSW regions in 2014 – 2016, increase in capacity out of Latrobe Valley of at least 300 MW by 2011 – 2013, etc. The NTP should compare options at this level of detail, that is, compare whether it is likely to be more economic to make a 250 MW or 1000 MW increase in capacity across the corridor. It should not undertake comparisons of the economics of the different detailed technical solutions which may achieve an increase of 250 MW should that be found to deliver net national benefits.

ETNOF considers that by adopting the outlook, content and analysis above, the new national transmission planning arrangements (particularly the NTNDP) will deliver a more strategic and nationally coordinated approach to transmission network development. This approach would also provide consolidated information to guide investors, with the aim of contributing to the optimisation of investment between transmission and generation across the power system. Identification of longer term generation developments for scenarios based on a range of plausible ‘future worlds’, and the analysis of the economics of nationally significant transmission development for those scenarios is the key element which will deliver COAG’s desired outcomes.

3.3 Scope of the National Plan

3.3.1 Electricity transmission or wider

The Commission seeks comments on:

- *To what degree should the three areas of power generation, gas transmission, and electricity distribution be in the scope of the national plan, and what specific functions should the NTP have to give effect to this?*
- *To what extent should planning of embedded generation, demand side management and NCAS provision be within in the scope of the Plan, and what specific functions should the NTP have in this regard?*
- *In what specific ways might the NTP add value if its remit were wider than electricity transmission planning, and how material would this added value be?*

Response:

The NTNDP should provide broad and comprehensive research and information to assist the integrated - but disaggregated - overall transmission planning process. The NTP should encompass a consideration of fuel sources for generation, and should reflect a well-founded set of views about possible future gas industry development, given the importance of gas as a fuel source for generation.

Distribution planning is clearly a local matter that is beyond the scope of the NTP. For the purpose of the NTP, distribution load should be considered in terms of load serving (exit) points of connection on the transmission network. This approach would be appropriate given that network developments which are primarily load serving are largely independent of the location of major generation and, in particular, developments by other TNSPs. Therefore, only the assumption that such developments will occur need be included as part of the NTNDP. Load serving parts of the network will be developed by relevant TNSPs in the normal course of business to meet their reliability and performance obligations. These will necessarily be addressed in TNSP Annual Planning Reports, and other consultation reports required under the Rules.

ETNOF considers that the mechanism to account for non-network solutions in a strategic timeframe need to be incorporated into the specification of the NTNDP. Properly developed scenarios should consider the level of demand side and distributed generation that is realistically expected to emerge as a matter of course. Consultation on these assumptions would allow for stakeholder response. It will be important for the NTNDP to neither overstate or understate the likely range of demand side response.

3.3.2 Network augmentation or wider?

The Commission seeks views on:

- *Whether the coverage of network assets for the NTNDP be limited to main grid augmentations, and if so, how should "main grid" be defined?*
- *The appropriateness of applying a threshold test ($ value or MW) to determining the coverage of network assets in the NTNDP?*

Response:

The NTNDP will necessarily consider the capacity of existing and future transmission corridors of national significance. These will need to be identified on a case by case basis for each scenario and be limited to existing and potential corridors which either presently, or over the life of the NTNDP, are expected to frequently carry material flows thereby providing enduring benefits to the national economy. Criterion for determining these corridors are whether network requirements are:

- sensitive to the location and type of future generation, and hence affect competitive market investment decisions; and
- significant in the scenario, particularly where interstate or high volume transfers are integral to the scenario and affect the planning activities of more than one TNSP.

Major network developments to be noted in the NTNDP would include:

- notional nationally significant transmission corridors where none currently exist – as part of the economic development of major new generation centres or to bypass expected congestion points;
- existing corridors that may require capacity expansion; and
- possible voltage levels and technology choices (eg. HVAC versus HVDC) for new or upgraded corridors, bearing in mind expected capacity requirements.

Any potential solutions identified in the NTNDP must take into account the practicality of any such developments (for example, recognising that a new transmission corridor must avoid areas of high conservation value, or areas designated for urban development). It is not intended for corridors to be defined to the level of geographical precision required for, say determining the alignment of transmission line easement.

3.4 Other Scope Issues

3.4.2 Forecast period of the NTNDP

The Commission seeks views on:

- *Whether the forecast period for the NTNDP should be longer than the minimum ten years?*

Response:

ETNOF's view is that the timeframe covered by the NTNDP should start no earlier than 5 years ahead and run to at least 15 years possibly 20 years. The reasoning for this is that the planning horizon of the NTNDP must be long enough to encompass a range of plausible alternative 'future worlds', having regard to alternative generation technologies, fuel sources and climate change policies, as well as the long lead times associated with the development of alternative fuel sources. The starting time should build on where the TNSP Annual Planning Reports end and extend far enough into the typical lifecycle of network investments.

3.4.2.3 Relationship with other Planning Documents

The Commission seeks views on:

- *The relationships between the NTNDP and other planning documents.*

Response:

The relationship between the NTNDP and the Annual Planning Reports published by TNSPs is best illustrated by considering the respective roles of the NTP and TNSPs, noting that there must be no duplication of effort between the two parties. The role of the NTP should be to:

- develop scenarios and key input parameters such as:
    - demand; and
    - generation technologies (eg. performance and cost);
- develop NEM-wide, broad, plausible scenarios for generation development to meet NEM supply/demand balance and to identify national transmission corridor capability requirements for each scenario;
- identify notional, transmission corridor developments of national significance. In particular, the sequence of possible strategic developments and the anticipated broad timing of these which efficiently satisfy the scenario/s that underpin them;
- publish the information identified above as part of the NTNDP, with a 5 to 15 or 20 year outlook;
- provide an annual update of the NTNDP, which also takes account of the results contained in each TNSP's Annual Planning Report; and
- include in the NTNDP, the data, assumptions and analysis which underpin the NTNDP.

The role of TNSPs should be to:

- conduct detailed planning and economic/engineering analysis of potential options to address identified network needs which:
    - efficiently satisfy reliability and other legislative obligations;
    - take account of the broader, strategic outlook of the NTNDP, including identified national transmission corridor developments;

- make investment decisions. This requires that TNSPs:
    - make provision for prudent and efficient capital (and operating) expenditure in their respective Revenue Proposals;
    - conduct the Regulatory Test analysis and related Rules consultations for all investments required to meet its mandated and other obligations;
    - make other transmission network investment decisions as required; and
- prepare and publish the Annual Planning Report, which reflects a short to medium term view of network development (1 to 5 plus years).

ETNOF has not considered the relationship between the NTNDP and the SOO although it notes that the current inclusion of the ANTS in the SOO document is considered satisfactory. It may therefore be appropriate if the NTNDP replaced the ANTS within the SOO document.

3.4.2.4 Research on Network Issues

The Commission seeks views on:

- *Whether the NTNDP should also contain research on issues relating to transmission network planning?*

Response:

The NTP will necessarily have to undertake research of relevant government policy developments; costs of generation development; economic outlooks; impacts of transmission planning arrangements; and other factors to prepare the scenarios to be used in the NTNDP. Publication of this research should occur in the NTNDP and will contribute to stakeholder knowledge and understanding of those issues thereby promoting debate and transparency around the issues.

3.5 Relationship between National Planner and TNSP Planning

The Commission seeks comments on:

- *The possible options for additional involvement for the NTP with respect to the planning carried out by the JPBs.*
- *Whether making TNSP provide statements to explain any deviations from the National Plan would impinge on the TNSPs accountability and would be beneficial to market participants.*

Response:

ETNOF's view of the scope and functions of the NTP and the NTNDP are discussed in response to the matters raised in sections 3.1 and 3.4.2.3 in particular. The NTP's primary role is the collation, analysis and dissemination of high level information which provides a national perspective regarding the long-term development of the national power system under a range of plausible scenarios.

The Commission has recognised that the recommendations coming out of its review must be consistent with the specific wording of, and broad intent underpinning, the direction provided by the COAG decision. ETNOF emphasises that the NTP and NTNDP must be implemented in a way that avoids duplication of effort and blurring of accountabilities, including with the accountabilities of the AER.

An important aspect of COAG's decision is the relationship between the NTNDP and other regulatory processes such as the implementation of the Regulatory Investment Test, and the economic regulation of TNSPs by the AER. In essence, and in accordance with COAG's requirements, the NTNDP is intended to inform these processes while leaving the clear accountability for investment decision and accountability for transmission service outcomes, with the TNSPs. Likewise, the NTNDP is intended to inform the revenue setting role of the AER, recognising that the AER's revenue decisions must be formulated on the basis of a broad range of considerations as set out in Chapter 6A of the NER.

The COAG decision notes that the NTNDP will be non-binding on TNSPs and the AER. However, consistent with good industry practice, and in accordance with the consultation and investment decision-making processes set out in the NER, TNSPs are required to explain the basis of their investment decisions with reference to all key considerations, which could include the views expressed in the NTNDP.

3.6 Additional National Transmission Planner Functions

3.6.1 Inter-regional Planning Committee

The Commission seeks view on:

- *How should the current IRPC functions be incorporated into new national planning transmission arrangements?*
- *It is necessary and/or beneficial for the NTP to have advice from the state JPBs in exercising the IRPC functions, especially the technical work performed under the umbrella of the IRPC.*

Response:

One option worthy of more detailed examination is transferring responsibility for convening the IRPC from NEMMCO to the NTP.

Experience to date suggests that neither NEMMCO nor the NTP could perform the functions of the IRPC without the considerable support of the JPBs and TNSPs. The ongoing support of the JPBs and TNSPs is therefore both necessary and beneficial. The creation of the NTP function is unlikely to change the underlying need for the (largely) technical role performed by the IRPC.

3.6.2 Other tasks currently performed by JPB/TNSPs

The Commission seeks views on:

- *Should such functions be transferred to the NTP?*
- *Are there other similar functions that could be transferred to the NTP?*

Response:

Functions such as co-ordination of emergency response, communication under the Responsible Officer Role and maintenance of Load Shedding Schedules and Sensitive Loads are local (jurisdictional) operational matters that should not be transferred to the NTP. ETNOF therefore agrees with the statement in the Issues Paper that:

> "The NTP should only be assigned functions which have a national focus and assist in meeting the purpose of ensuring a more strategic and nationally co-ordinated approach to transmission planning"(p34).

3.6.3 Possible additional responsibilities for the NTP

The Commission seeks views on:

- *Whether such additional functions be assigned to the NTP?*

Response:

In relation to the functions listed on pages 34 and 35 of the Issues Paper, ETNOF's views are as follows:

(a) *Provision of advice to MCE*: The NTP could provide advice to the MCE on matters relating to future capability and reliability of the NEM;

(b) *NCAS planning and procurement* is an operational matter and one that has implications for TNSPs' accountability for performance of the transmission network. Transfer of this function to the NTP would therefore conflict with the COAG directive for this review;

(c) *Responsibility for State Load Forecasts* should remain with the JPBs/TNSPs;

(d) *Monitoring the technical performance of TNSPs and their networks* is a regulatory and enforcement role presently undertaken by the AER. It would be inappropriate for the NTP to be assigned this role;

(e) *Generic constraint equations for use in the NEMDE*. This is an operational matter that is beyond the scope of the NTP. Transferring responsibility for this function to the NTP would raise issues regarding TNSP accountability for network performance, and be inconsistent with the COAG directive for this review; and

(f) *Advice to TNSPs on easement procurement*: Advice regarding possible requirements for new transmission corridors over a 20 to 30 year planning horizon would be a useful task for the NTP to undertake. It is not intended for corridors to be defined to the level of geographical precision required for, say determining the alignment of a transmission line easement.

Chapter 4 Project Assessment and Consultation Process

4.1 Amalgamating Reliability and Market Benefits

4.1.3 Framework for a new Regulatory Investment Test (RIT)

The Commission seeks views on:

- *The proposed broad framework for developing a new RIT?*
- *The Commission's observations on the desirable characteristics of an RIT?*

Response:

The Commission's proposed broad framework for development of a new RIT identifies key issues to be resolved in amalgamating the two limbs of the Regulatory Test. In particular, ETNOF agrees that the range of costs and benefits which can be used in the RIT should be consistently applied by TNSPs and for pragmatic 'rules of thumb' to be applied in an objective and transparent manner.

In ETNOF's view, an important characteristic of the RIT is that it is sufficiently flexible to enable TNSPs to allocate their analytical resources efficiently by distinguishing between augmentations:

- where there is little to be gained from expending significant resources on the RIT analysis, eg, because wider market benefits are likely to be immaterial or no plausible network or non-network alternatives exist; and

- where there are likely to be wider market impacts and/or plausible network and non-network alternatives that warrant analysis and, consequently, require more extensive consultation and evaluation.

Adoption of a 'fit for purpose' approach that recognises the key differences between applications is particularly important in light of the explicit directive from COAG that the new regime must be no slower than the present regime. It also minimises the resource cost implications on TNSPs and other market participants. Approval times could be further reduced if the RIT consultation processes occur in parallel with other approval processes, eg, environmental impact assessments.

The Commission has raised the question of how under Option 3, the types of costs and benefits could be ruled as immaterial (and thus not warranting further examination) without first measuring them. ETNOF agrees that in some cases it will be necessary to undertake a measurement exercise in order to determine materiality. However, that does not obviate the prospect in other circumstances of adopting 'rules of thumb' or undertaking straightforward assessments in order to determine materiality that are less resource intensive.

In many situations it may be relatively easy to assess the magnitude of the *maximum* benefit that may be associated with a network augmentation. For example, in estimating the impact of an intra-regional augmentation on the generation market, the maximum impact could be characterised as the complete displacement of a local generation plant of the same MW magnitude as the incremental capacity impact of the augmentation. By definition, if this maximum impact is immaterial, so too will be the actual impact, obviating the need to undertake complex generation market modelling of what generation may *actually* be deferred and for how long.

Accordingly, ETNOF does not consider that the issue raised by the Commission undermines the ability to employ time saving 'rules of thumb' or more straightforward assessments. In ETNOF's view, any measure which better enables TNSPs to quickly distinguish between costs and benefits likely to be of importance for a particular augmentation and those that are immaterial should be encouraged. TNSPs can then focus an appropriate level of analytical resources on those augmentations where there are likely to be material market benefits and a broader array of alternatives.

Any interested party can provide input and comment on the assessment by the TNSP through the consultation process if it does not accept a TNSP's reasoning for the non-inclusion of a particular benefit category. Ultimately such a party could dispute the analysis as part of the consultation process. Accordingly, such time saving initiatives would enable the minimisation of time and resource costs, but would entail sufficient transparency to allow market participants to raise any issues that they might have with the TNSPs reasoning or analysis.

ETNOF notes that under the Commission's Option 1 it would not be possible to adopt 'rules of thumb' or undertake straightforward assessments because all costs and benefits must be measured (including reliability benefits as 4.4.1.2 explains), whether they are material or not. This will entail greater resource outlays and extend the timeframes for RIT assessments due to the increased complexity and attendant need to spend more time on analysis and consultation – which in all likelihood, will not change the outcome of the RIT.

A large number of intra-regional transmission augmentations occur as a result of joint planning between TNSPs and DNSPs. DNSPs also require certainty as to the level of reliability delivered to their networks. ETNOF considers that most of these types of investments involve negligible market impacts. In light of this, the application of Option 1 would unnecessarily complicate the interaction of transmission and distribution investment assessments.

4.1.3.1 Scope of situations to be subject to the RIT

The Commission seeks views on:

- *Whether the scope of situations subject to the RIT should include network reconfigurations and replacement expenditure?*

Response:

In ETNOF's view, there are compelling reasons for the RIT to continue to distinguish between these types of expenditure and augmentations.

Network replacements are predominantly undertaken on a 'like-for-like' basis because there are no network or non-network alternatives. The reason is that once a network is configured in a certain way it is usually infeasible to replace the components of that network with anything that differs materially to those in situ. Consequently, there are no obvious changes in service levels to customers or realistic opportunities for non-network alternatives associated with a 'like for like' replacement scenario. This type of expenditure therefore has no material consequences for market participants. Hence it would be inappropriate and inefficient for the RIT to have any application in this context.

In some situations a strict 'like-for-like' replacement may not be possible or appropriate, for example:

- changes in technology may result in an 'unavoidable' increase in capacity where the most cost effective replacement has a higher capacity;
- current good electricity industry practice may dictate the use of higher capacity plant, eg. to ensure compatibility with similar plants in a network;
- there may be new statutory requirements that lead to an unavoidable increase in capacity, eg. where environmental or occupational health and safety requirements result in increased capacity plant being mandated; and/or
- a replacement project may be combined with an augmentation project, eg. an aging substation may be replaced with larger capacity transformers to meet expected load growth.

Nonetheless, this replacement expenditure remains quite distinct from augmentation expenditure, because:

- replacement expenditure decisions are governed by considerations primarily related to network performance and safety risk management;
- decisions are the product of a fundamentally different planning approach that depends more critically upon the optimal timing of investment given the condition of the infrastructure in situ than how that investment will be undertaken; and
- market benefit considerations almost never arise in relation to replacement expenditure.

Moreover, just as for a pure 'like-for-like' replacement, there will generally be no reasonable alternative projects available (either network or non-network). Consequently, there is little to be gained from expending significant resources on a RIT consultation process for such investments. A limited exception exists where replacement work is conducted in conjunction with an augmentation. Currently a Regulatory Test evaluation and Rules consultation process is undertaken for the incremental investment cost represented by the augmentation, consistent with the Rules. ETNOF recommends that the new RIT also be applied in these circumstances.

Similarly, network reconfigurations that result in changes in transmission capability or service levels to network users would be treated as augmentations for the purpose of the RIT.

Notwithstanding the substantive points made above, ETNOF considers it appropriate to require TNSPs to disclose certain information on replacement project which cost above $5 million to provide the opportunity for interested stakeholders to comment on any project of interest. ETNOF recently lodged a Rule Change Proposal with the Commission to this effect.

Continuing to confine application of the RIT to augmentations is also consistent with COAG's directive that the RIT not extend the timeframe taken to gain regulatory approval for investment. In this context it is important to consider the availability of suitable resources to undertake the additional work that would be required if the RIT were extended to include the analysis of replacement or re-configuration decisions. The inclusion of replacement projects under the RIT would also result in a significant increase in resources required to undertake RIT analyses, with attendant impacts on network charges and final prices to consumers.

Consequently, if TNSPs were required to undertake substantially more RIT analyses they would likely do so by stretching their existing resources more thinly (because of the very limited availability of suitable external resources). As a result, each application of the RIT is likely to take longer and cost more, which would be inconsistent with COAG's directive.

4.1.3.2 Identification and quantification of costs and benefits

The Commission seeks views on:

- *Whether the RIT should mandate the types of impacts to be included in any project assessment?*
- *Approaches to valuing reliability benefits?*
- *What the list of mandated impacts should be, and whether in particular competition and risk management impacts should be included?*

Response:

ETNOF supports amalgamation of the reliability and market benefit limbs of the Regulatory Test along the lines of Option 3 as described in the Issues Paper. However, COAG's directive to amalgamate the Regulatory Test reliability and market benefits criteria does not translate into 'doing away with' the assessment of reliability driven augmentations.

To better ensure the consistent treatment of market costs and benefits by TNSPs, it would be useful to develop a standard list of data which could be used in the assessment of alternative options under the amalgamated RIT. Data should be provided for:

- Estimates of non-transmission costs such as fuel costs and generation development costs; and
- National benefit components such as benefits arising from impacts in the generation market, eg. change in dispatch costs and/or deferral of generation investment where these differ between options.

ETNOF considers that an assessment of competition benefits should be *optional* for all investments, as it is now under the market benefit limb (discussed further in 4.1.3.4 below). TNSPs must also have sufficient flexibility in assessing those costs and benefits in RIT appraisals to enable a 'fit-for-purpose' approach (as discussed in 4.1.3 above).

Regarding the approach to valuing reliability benefits, for the reasons outlined in 4.1.3.6 below, ETNOF does not consider that valuing reliability benefits when undertaking a RIT analysis is consistent with a reliability standard derived from economic considerations. Reliability benefits will have already been considered in a separate prior process when the reliability standard was established. Risk management impacts as they relate to reliability improvements should be excluded from a RIT analysis for the same reasons.

4.1.3.3 Avoiding wasted effort

The Commission seeks views on:

- *How, specifically, will a more comprehensive routine assessment of costs and benefits by TNSPs impact on planning timescales – and to what extent can this be addressed through the commitment of additional resources by TNSPs?*
- *How should the concept of proportionality be reflected in how the RIT is applied?*

Response:

<u>*Impact on Planning Time Scales*</u>

There are at least three reasons why a more comprehensive assessment of costs and benefits by TNSPs on a routine basis impacts on planning time scales. These are:

- Far greater computational effort by TNSPs;
- Incompatibility between the TNSP and DNSP assessment methodologies when carrying out joint investment assessments; and
- Significantly increased potential for disputation.

Of these only the first matter can be impacted materially by the commitment of additional resources by TNSPs, assuming availability of relevant skilled resources are unconstrained in the short to medium term.

A key difference between Option 1 and Option 3, as set out by the Commission, is that under Option 1 the level of reliability delivered by a proposed augmentation (and alternatives to that augmentation) is *explicitly valued* as part of the cost-benefit analysis. In contrast, under Option 3, the required level of reliability is determined by a separate, prior process and is then *taken as given* when conducting the RIT assessment.

Where an investment is primarily driven by reliability concerns, under Option 3 only those investments that meet (or exceed) the mandatory reliability standard are considered in the RIT assessment. As a general rule, any incremental improvement in reliability over and above the mandated standard would not be taken into account as part of the RIT assessment.[4]

In contrast, under Option 1, the level of reliability provided by alternative options is itself included in the RIT analysis. Therefore, it follows that under Option 1, the level of reliability delivered by the augmentation need not be equal to the level of reliability determined by the body setting the mandatory reliability standard – which suggests that the outworked standard may be above or below this standard.

Therefore, a key distinguishing feature between Option 1 and Option 3 is that Option 1 requires the level of reliability resulting from alternative augmentations (or non-network options) to be *explicitly valued* in relation to all RIT applications. In practice this is likely to be achieved though estimating the expected level of unserved energy (USE) associated with an augmentation and then applying a value per MWh to this level of USE.

Estimating the USE expected to result from an augmentation for each and every project assessment is a significant network modelling task, involving the computation of load flows. Similarly, the value of USE for each expected level of unserved energy is highly variable across customer class, time of day, time of year and geography. It would therefore need to be assessed for each connection point, and then updated on a regular basis.

The increased complexity of the analysis under Option 1 for investments primarily driven by reliability considerations is explicitly recognised by the Commission.[5] In addition to the need to explicitly model changes in USE, Option 1 as defined by the Commission does

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[4] Section 6 discusses circumstances in which it may be appropriate to relax this general rule.

[5] AEMC, *National Transmission Planning Arrangements: Scoping Paper*, August 2007, p. 14.

not incorporate a materiality provision. This implies that all costs and benefits would need to be modelled for all RIT assessments, even where some of the benefits are not expected to be material.

The complexity of such an analysis not only consumes valuable, scarce, skilled resources, but is less transparent and more open to disputation. Taken together the prospect for delays in the conduct of Regulatory Investment Test consultations is assured in most cases and would be expected to be material. Such an outcome will clearly impact the overall timing of investment decision making and project delivery. As a consequence, ETNOF considers that Option 1 is inconsistent with COAG's directive that the new planning processes do not add delays to the current timelines for delivery of required investment.

A further key issue is the need to ensure compatibility between the approach taken to the amalgamation of the limbs of the regulatory test and the joint planning undertaken by TNSPs and distribution network service providers (DNSPs).

Irrespective of the arrangements to enhance coordination of national planning, augmentation and development of local and regional electricity networks will continue to occur through joint planning and investment analysis between TNSPs and DNSPs. By way of example, the joint planning around the border areas of Gold Coast/Tweed and Goondiwindi involves the TNSPs and DNSPs from both regions. Similarly, a joint Regulatory Test evaluation has recently commenced in the Newcastle load area and since 2003 TransGrid has undertaken 15 New Large Transmission Network Asset consultations, of which 11 were published jointly with a DNSP. The National Electricity Rules require such joint planning,[6] which ensures that the capacity of the transmission network is sufficient for the purposes of conveying power to the distribution network and, ultimately, to end-use businesses and customers. The joint planning also ensures the most efficient outcome for customers (consistent with the Market Objective) and this is often a combination of TNSP and DNSP augmentations.

In most cases, NEM DNSPs are required to plan their networks to meet deterministic planning standards set exogenously, usually by a relevant jurisdictional body. In undertaking joint planning, DNSPs require certainty that the level of reliability delivered by the transmission network will be sufficient to enable the DNSPs to meet these mandated reliability standards.

Given this situation, it is clear that Option 1 *is not compatible* with delivering the certainty that DNSPs require in relation to the level of reliability delivered by the transmission network. This is because under Option 1 the level of reliability is an uncertain endogenous outworking of the cost benefit analysis, rather than a firm, transparent exogenous standard to which DNSPs can plan. In addition, given that DNSPs are obliged to meet a deterministic standard, Option 1 is not compatible with the identification of a least-cost joint TNSP/DNSP solution, and would therefore result in a move away from the Market Objective.

It is noted that the scope of the Reliability Panel's review regarding the framework for reliability standards does not include DNSP reliability standards. This is a significant issue in NEM jurisdictions where DNSPs own significant subtransmission assets, and where joint planning for least cost outcomes typically results in a combination of complementary TNSP/DNSP augmentations.

For these reasons it is clear that the joint planning process between TNSPs and DNSPs would be a convoluted process under Option 1. As such it would be expected to take longer and would be more likely to confuse interested stakeholders, including the AER. As a result, once again, the prospect for disputation is increased and the difficulties faced by the AER in resolving disputes compounded. This, in turn, would add to the time taken to resolve disputes.

[6] NER, 5.6.2 (a1)-(c).

Clearly, additional resourcing by the TNSPs would have minimal impact on the inherent lack of transparency of Option 1 and complexity of joint planning with DNSPs, or the increased risk and delays of dispute.

Applying the Concept of Proportionality to the Application of the RIT

The Commission has also asked how the concept of proportionality should be reflected in the way the RIT is applied, suggesting that the current $10 million threshold for large network assets may not ‘capture all necessary projects’.

ETNOF does not consider that there is a material risk of this occurring. The reasons for this are highlighted in ETNOF’s Rule Change Proposal of 21 November 2007. In summary:

- a very limited number of transmission network augmentations can be constructed for a capitalised value of less than $10 million;
- in the majority of these cases, there are few, if any, feasible network alternatives and no non-network alternatives; and
- in any event, experience demonstrates that market participants and interested parties have shown negligible interest during the consultation on investments up to and beyond $35 million, apart from being informed at a high level that such network developments are being proposed.

Consequently, if a pre-determined threshold is to be maintained, arguably proportionality would be better served if that threshold *increased*. ETNOF proposed to increase the thresholds to:

- $5 million for small transmission network assets; and
- $35 million for new large transmission network assets (this was also the threshold postulated by the Commission in its Final Determination on Stanwell’s proposed revision to the Regulatory Test, being the midpoint of the $20-$50 million range it perceived as appropriate).

Commensurately, ETNOF proposed that TNSPs be required to disclose information on all network projects (including replacements) in excess of $5 million, including:

- a brief description of the project; and
- the planned commissioning date.

In this way, market participants are provided with all relevant information relating to network augmentations and replacements that may affect them in some manner. Therefore, ETNOF does not perceive there to be significant downside associated with the RIT not being applied to projects below the $35 million threshold.

If a defined threshold is not retained it will be vital to ensure that any screening process enables TNSPs to quickly identify where there are likely to be material market benefits and/or plausible network and non-network alternatives. In particular, as outlined in 4.1.3, to ensure that analytical resources and effort can be allocated most efficiently and effectively, it will be important to distinguish between augmentations:

- where there is little to be gained from expending significant resources on the RIT analysis, eg. because wider market benefits are likely to be immaterial or no plausible network or non-network alternatives exist; and
- where there are likely to be wider market impacts and/or plausible network and non-network alternatives that warrant analysis and, consequently, require a more extensive consultation and evaluation process.

Irrespective of whether a defined threshold is included, the RIT must be sufficiently flexible to distinguish between these two broad situations so as to enable appropriate proportional treatment. TNSPs must be able to devote time and resources where they are most needed when undertaking their investment planning processes, particularly in light of the explicit directive from COAG that the new regime must be no slower than the present regime. It also minimises the resource cost implications on TNSPs, other market participants and ultimately, electricity consumers. In other words, it is important to design a RIT that is sufficiently adaptable to be 'fit-for-purpose' in different scenarios.

Finally, it will be more difficult to incorporate any concept of proportionality in the application of the RIT if Option 1 is implemented. As 4.1.3 explains, under Option 1 it would not be possible to adopt 'rules of thumb' or to undertake straightforward assessments because all costs and benefits must be measured (including reliability benefits), whether they are material or not. This will entail greater resource outlays and extend the timeframes for RIT assessments due to the increased complexity and attendant need to spend more time on analysis and consultation.

4.1.3.4 Inclusion of national market benefits

The Commission seeks views on:

- *Whether, the Commission is correct in its view that the existing text in the Rules determining the scope of 'national' benefits is sufficient for the purposes of the new RIT?*
- *If the current Rules remain, whether there would be benefit in expanding the operational guidelines on determining national benefits?*

Response:

If the current Rules remain, ETNOF does not consider that there would be benefit in expanding the operational guidelines to include a separate assessment or category of 'national benefits'. The current Regulatory Test already identifies benefits to be considered in market benefits assessments and contains several that have a distinctly national focus.

Amalgamating the two limbs of the Regulatory Test should serve to ensure that these types of market benefits are incorporated consistently in all RIT assessments, including investments driven by the need to meet reliability obligations. In other words, the existing regulatory test already ostensibly provides for 'national benefits', but implementing a 'fit for purpose' approach to the application of the RIT would provide a greater opportunity for those benefits to be consistently and appropriately addressed where they are material for all types of augmentations.

4.1.3.5 Range of Options to be considered

The Commission seeks views on:

- *What additional information should be released to support identification of options?*
- *What options must be included in the assessment?*
- *Whether the NTP should advise the TNSPs on the range of possible options to be assessed under the RIT.*

Response:

<u>*Identification of Options for Inclusion in an Assessment*</u>

The Commission's reference to ERIG's concerns in this section of the Issues Paper as to whether proper evaluation of all possible options is being done is of concern. A feature of this discussion in the ERIG report was a lack of evidence to support this contention. It may be for this reason that this matter was not highlighted in the COAG requirements for this review.

In contrast to the ERIG report ETNOF notes that TNSPs currently have both the incentives and mechanisms for identifying a full range of feasible options and providing information to the market on these options. Information provision occurs through a number of mediums, including:

- Annual Planning Reports;
- Regulatory Test evaluations and Rules consultation process for transmission augmentations; and
- Requirements of the new Request For Information (RFI) process contained in Version 3 of the Regulatory Test.

In addition, the parties that take an active interest in this information are often well resourced and highly motivated to analyse and, if need be, dispute TNSP proposals. These parties include affected generators and retailers, demand side aggregators, and other network businesses. These parties also have access to dispute provisions provided for in the Rules which include a role for the AER to resolve disputes.

Furthermore, Chapter 6A of the Rules requires TNSPs to fully disclose the basis of their capital expenditure forecasts at the time of a revenue cap application. Failing to do so puts a TNSP's entire provision for future capital expenditure at risk. The composition of these forecasts is then forensically evaluated in the public domain by both the AER and expert consultants. One matter routinely examined is whether projects subjected to the Regulatory Test are the result of consideration of all feasible options.

Finally, the Commission has a Last Resort Planning Power which can be invoked if there are reasonable concerns that efficient transmission development options have not been subjected to a Regulatory Test assessment process.

Taken together these facts demonstrate ample incentives for TNSPs to consider and disclose the full range of feasible options supported by an extensive range of mechanisms to give effect to this disclosure. On this basis ETNOF considers that current requirements to consider network, demand-management and generation options in the assessment are reasonable and could be retained.

<u>*Should the NTP Advise on the Options to be Assessed*</u>

An additional requirement for the NTP to advise TNSPs on the options to be considered when conducting a Regulatory Investment Test does not appear to add any real value to the planning and investment process arrangements contemplated by COAG.

As previously observed in this submission a role of the NTNDP, proposed by COAG, is to inform the investment decision making by generators and TNSPs. This is to be achieved via the NTNDP being published annually by the NTP.

ETNOF considers COAG's requirements are best met by an NTP that fills the current gaps in identifying worthwhile strategic transmission developments for the period beyond the normal investment horizon of TNSPs and generators i.e. 5 to 15 or even 20 years. The NTP would also assume carriage of the IRPC process and ensure that the information in the Annual National Transmission Statement (ANTS) was published, either as part of the NTNDP or separately.

The Regulatory Investment Test is usually the final assessment of a proposed by the investing TNSP prior to committing expenditure to an investment and is typically conducted within 5 years of the completion of a development.

With this model in mind the NTP would have a similar role in relation to the Regulatory Investment Test as the current IRPC and ANTS. As such, it could continue to advise the Commission on the exercise of the Commission's Last Resort Planning Power, just as the IRPC currently does.

Finally, it should be recognised that <u>all</u> interested stakeholders are free to offer comment on any proposed transmission investment via one or more of the numerous consultation processes referred to above. Furthermore other interested stakeholders could use the NTNDP as a reference document when assessing TNSP Regulatory Test Assessments or revenue proposals.

In summary, to meet the COAG requirements as proposed by ETNOF, the NTP would already have an effective input into the options considered in the application of the Regulatory Investment Test. This includes via the NTNDP and via advice to the Commission on the exercise of the Last Resort Planning Power. As such any additional requirements to advise on options adds no further value to the transmission planning process.

4.1.3.6 Decision making Rule to determine which option passes the RIT

The Commission seeks views on:

- *Whether, and why, the valuation of reliability benefits is consistent with the practical application of a deterministic reliability standard framework?*
- *Whether there is a need for a more specific decision criterion for the revised project assessment process?*

Response:

Where a deterministic reliability standard is specified, such as redundancy criteria, ETNOF does not consider that valuing reliability benefits when undertaking a RIT analysis is a necessary part of the practical application of the standard for each and every investment. Currently, reliability standards are established (and periodically reviewed) by the jurisdictions[7]. A review of jurisdictional standards is generally carried out on the basis of economic considerations[8]. Such an approach provides a robust and effective basis for determining appropriate reliability standards and ensures that those standards are linked to economic considerations. This approach also has important advantages which includes transparency of application and clarity in the accountability of TNSPs for provision of service outcomes.

Given the above approach for determining reliability standards in each jurisdiction, and the

[7] Or a body appointed by the jurisdiction.
[8] Refer ESCOSA (2006), Review of the Reliability Standards Specified in Clause 2.2.2 of the Electricity Transmission Code, Final Decision, September.

current application of mandatory standards to TNSPs, it would be wholly inappropriate for valuation of the reliability benefits to form part of the decision regarding which option passes the RIT. To do so would override the separate, jurisdictional process for determining appropriate reliability standards. In effect such a valuation would require a TNSP to assess the reliability that would result from a proposed augmentation at the time of each RIT application and to, in effect, select a reliability standard in relation to each augmentation that the TNSP considers to be justified on the grounds of the cost benefit analysis.

It is clear that the choice between options for amalgamating the reliability and market benefits limbs of the Regulatory Test is necessarily affected by the framework adopted for determining appropriate reliability planning standards. In amalgamating the two limbs, ETNOF considers that the Commission should aim to develop a single, consistent methodology that can be applied to all augmentations, including those primarily driven by the need to meet established reliability standards.

Regarding whether there is a need for a more specific decision criterion, ETNOF does not consider that there is a pressing need for this. Uncertainty about future outturns is currently factored into the Regulatory Test through the requirement to consider alternative scenarios, and to select the option that maximises the benefit in the majority of these scenarios. As the Commission recognises, under Option 3, if an augmentation is reliability driven it may be necessary to choose the 'smallest negative' NPV of net market benefits.

4.2 Interaction between National Transmission Planning Function and Regulatory Investment Test

The Commission is keen to understand in more detail what stakeholders consider to be the strengths, weaknesses and wider implications of these four broad options, and in particular views on the following questions:

- *What value might the NTP add to the RIT process under each of the different broad options identified above?*
- *What particular aspects of an RIT methodology might the NTP specify or recommend?*
- *How binding should the views or recommendations of the NTP be on the party with primary responsibility for undertaking the RIT?*
- *How might a 'compliance and monitoring role interact with the AER's role of monitoring and enforcing compliance with the Rules?*
- *However it is not clear to the Commission if there is value in the NTP taking over the AER role in monitoring the application of regulatory tests.*

Response:

The first option identified by the Commission, which involves the NTP co-ordinating and disseminating information on good practice in applying the RIT appears to be of little value. RIT assessments would be published and available to all stakeholders to have input.

The relationship between the NTNDP and other regulatory processes such as the implementation of the Regulatory Investment Test, and the economic regulation of TNSPs by the AER is an important aspect of determining the national transmission planning arrangements. In essence, and in accordance with COAG's requirements, the NTNDP is intended to inform these processes while leaving the clear accountability for investment decision and accountability for transmission service outcomes, with the TNSPs. Likewise, the NTNDP is intended to inform the revenue setting role of the AER, recognising that the AER's revenue decisions must be formulated on the basis of a broad range of considerations as set out in Chapter 6A of the NER.

ETNOF considers that a useful role for the NTP in relation to the RIT process would be in researching and publishing (but not specifying) certain cost elements used in the RIT evaluation, in particular estimates of non-transmission costs (such as fuel costs and generation development costs) and national benefit components. Under this approach the NTPs information would provide guidance to TNSPs, but rightly enable TNSPs to legitimately depart from that guidance where there is good reason and the TNSP provides justification for doing so. Leaving the ultimate responsibility with TNSPs – albeit with guidance from the NTP – is wholly consistent with the COAG directive that TNSPs retain accountability for jurisdictional transmission investment, operation and performance.

For the same reasons it would be inappropriate for the NTP to have primary responsibility for applying the RIT 'in certain circumstances', as suggested in the Issues Paper. Doing so may also result in the duplication of roles, with attendant consequences for resource cost outlays and the time taken to undertake RIT appraisals. In these circumstances it would be unclear as to who would be the party of any dispute raised in response to the RIT assessment.

The NTP could usefully provide information and guidance on:

- fuel cost assumptions to be used ($/GJ for gas; $/tonne for coal, conversion efficiency);
- capital cost assumptions to be used for generation capex ($/MW);
- carbon cost assumptions to be used;
- methodologies for valuing non-network options, eg, whether this should be based on proponents' offers or on the basis of estimated resource cost;
- valuing reliability investment in generation (current market benefit limb); and
- approaches to the assessment of competition benefits.

Monitoring and enforcing compliance with the Rules should remain the sole responsibility of the AER. It would be inappropriate for the NTP to undertake such a role because it would be duplicative. The NTP itself should be subject to compliance oversight by the AER.

4.3 Last Resort Planning Power Function

Given the development of a National Transmission Planner the Commission seek feedback from interested stakeholders as to:

- *The purpose for the LRPP under the new arrangements;*
- *Who should be responsible for the LRPP;*
- *The status of the advisory role of the IRPC to the LRPP; and*
- *Any other comments regarding the application of the LRPP under the new arrangements.*

Response:

Whilst the existence of the NTP may *reduce* the risk of planning failure it will not remove it entirely.

To the extent that the LRPP is seen as a means of addressing this planning risk, then it should remain. There should be no change to the current arrangements for the LRPP whereby the Commission has the LRPP role and is able to take advice from the IRPC. Replacement of the IRPC role with the new arrangements as required by the COAG decision should be considered in conjunction with the other roles of the IRPC.

4.4 Provision for Urgent and unforseen Investment

The Commission seeks views on:

- *Why, specifically, different options for an RIT (and the role of the NTP in that process) might result in urgent or unforeseen investment being delayed?*
- *How would the RIT (and the role of the NTP in that process) need to be redesigned to assess the source of any such delay?*

Response:

The need for urgent investment does not necessarily represent a planning failure. Many unforeseeable factors can and do alter network investment requirements in the short-term, including sudden demand growth and/or drought affecting the pattern of generation dispatch.

The key issue is to ensure that the design of the RIT does not lengthen the time taken to obtain investment approvals when such circumstances arise, consistent with the directive from COAG. TNSPs must have the flexibility to devote time and resources where they are most needed, thereby minimising the time and resource cost implications for themselves, other market participants and ultimately, customers. In other words, it is important to design a RIT that is sufficiently adaptable to be ‘fit-for-purpose’ in different scenarios.

A key distinguishing feature between proposed Options 1 and 3 for the RIT is that Option 1 requires the level of reliability resulting from alternative augmentations (or non-network options) to be *explicitly valued* in relation to all RIT applications. In practice, this is likely to be achieved though estimating the expected level of unserved energy (USE) associated with an augmentation and then applying a value per MWh to this level of USE. Estimating the USE expected to result from an augmentation for each and every project assessment is a significant network modelling task, involving the computation of load flows. Similarly, the value of per MWh for each expected level of unserved energy is highly variable across customer class, time of day, time of year and geography. It would therefore need to be assessed for each connection point, and then updated on a regular basis.

The increased complexity of the analysis under Option 1 for investments primarily driven by reliability considerations is explicitly recognised by the Commission.[9] In addition to the need to explicitly model changes in USE, Option 1 (as defined by the Commission) does not incorporate a materiality provision. This implies that all costs and benefits would need to be modelled for all RIT assessments, even where some of the benefits are not expected to be material.

The complexity of such an analysis not only consumes valuable, scarce resources, but is less transparent and more open to disputation. Taken together, the prospect for delays in the conduct of Regulatory Investment Test consultations is assured in most cases and would be expected to be material. Such an outcome will clearly impact the overall timing of investment decision making and project delivery. As a consequence, ETNOF considers that Option 1 is inconsistent with COAG’s directive that the new planning processes do not add delays to the current timelines for delivery of required investment.

The importance of timing also reinforces the need for TNSPs to retain sole responsibility for undertaking RIT appraisals. In particular, the application of the RIT and associated consultation process can be conducted in parallel more readily with environmental approval and other processes if both are conducted by the one body – the TNSP. The involvement of a third party such as the NTP will likely make this process more sequential, extending the timeframes and blur accountabilities. Moreover, as noted in 4.2, because the TNSP (not the NTP) is ultimately accountable for investment outcomes and network performance, arguably the NTP would not have the same level of motivation to meet timeframes as the TNSPs.

[9] AEMC, *National Transmission Planning Arrangements: Scoping Paper*, August 2007, p. 14.

4.5 Detailed design issues

The Commission seeks views on:

- *Need for a proponent for reliability driven options; and*
- *Appropriateness of the RFI process to "reliability investments"*

Response:

For reliability driven options, ETNOF considers that a proponent should be required to ensure that investment is not delayed by unsubstantiated claims that alternative network or non-network options exist. The requirement was added in the previous review of the Regulatory Test to address this very concern. It must be retained to be consistent with the COAG directive that the timeframes for RIT appraisals are not lengthened.

By contrast, the lengthy, detailed RFI process outlined by the AER for market augmentations is likely to be inconsistent with COAG's directive against lengthening the RIT timeframes. ETNOF also does not consider that introducing a RFI process would necessarily deliver more non-network options. In ETNOF's experience it is only when very large investments are potentially deferred resulting in substantial potential funds being available for non-network solutions that serious options come forward. In addition, for non-network solution providers to become a critical element in maintaining reliability of supply, in addition to receiving payments they must also share in the liabilities which apply to TNSPs in the event that reliability standards were not met. Given the difference in availability of network and non-network solutions this risk may be substantially higher for the non-network solution provider compared to the network solution. ETNOF considers that the most effective way of eliciting proponents of non-network alternatives would instead be to provide TNSPs with a specific incentive to do so through the regulatory pricing framework.

Importantly, the Commission has correctly noted that TNSPs must already consult on investment options, including small and large reliability augmentations, as part of the APR process. In light of this requirement and the comments noted above, the RFI process is not necessary for reliability augmentations (or arguably even for market augmentations).

Chapter 5 Revenue and Pricing Framework

5.1 Simultaneous Reviews for TNSPs revenue determination

The Commission seeks views on:

- *The costs and benefits of aligning the timing of TNSP revenue determination, in the context of different models for NTP functions and NTNDP content – and in the light of the considerations identified as relevant by the Commission?*
- *Whether, and why, the current (or amended) contingent projects mechanism represents an adequate alternative to the alignment of transmission revenue resets?*

Response:

ETNOF considers that alignment of revenue reset reviews is unlikely to have any material beneficial impact on national transmission planning outcomes and that there are no obvious synergies that would reasonably be expected to be achieved as a result of simultaneous reviews. In fact, the simultaneous preparation and consideration of a number of TNSP revenue proposals within a compressed timeframe is likely to diminish consideration of national transmission matters rather than enhance them.

Submissions on the Commission's Scoping Paper highlight that there is no support for simultaneous TNSP revenue reviews. This sentiment has most clearly been expressed by the AER, citing the practical, technical and other resourcing issues associated with such an undertaking.

Empirical evidence suggests that the level of potential augmentations involving multiple TNSPs is unlikely to be material in the overall context of a TNSP's total investment. For example, in the case of Powerlink, the potential upgrade of QNI constitutes approximately 7% of Powerlink's contingent project allowance and just over 2% of its total capex allowance (ex-ante and contingent project allowance). This is clearly not sufficiently material to warrant simultaneous revenue reviews. Further, planning and regulatory processes currently in place to address the inter-regional impacts of investment (eg. joint planning between TNSPs and public Rules and Regulatory Test consultation process) are working adequately.

Given the level of uncertainty surrounding the timing and cost of inter-regional investments, ETNOF also considers that the contingent project mechanism provides an appropriate mechanism to deal with these types of issues. The regime ensures that where a trigger for upgrade is activated and demonstrated, TNSPs can undertake all the necessary analysis and processes associated with the investment with a degree of certainty that the expenditure will be recognised under the regulatory framework. It is also efficient in that customers do not unnecessarily pay for such highly uncertain investments.

A key mechanism of the contingent projects regime is the pre-defined trigger event, which must be satisfied before an investment proceeds and its costs included in the TNSPs regulated revenue., The definition of the trigger is completely unrelated to the timing of the relevant TNSPs revenue reset. The current contingent projects mechanism therefore provides an efficient an effective way of dealing with lage project uncertainties, while the alignment of revenue resets would serve no purpose in terms of dealing effectively with large project uncertainties. The AER can readily ensure that the triggers are consistent between the relevant TNSPs even with revenue resets on different timeframes.

5.2 National Transmission Planning Functions and the process of AER Revenue Determinations

The Commission seeks comments on:

- *How should the relationship between the AER and the NTP be defined?*
- *What should be the basis upon which advice is provided, and what should be the status of any such advice? How should this be specified in the Rules?*
- *What value will such arrangements add to the process of revenue determinations, and are they consistent with the COAG requirements in respect of process timescales?*

Response:

The relationship between the AER and NTP must be consistent with the boundaries established by COAG in that the NTP and NTNDP are to provide a strategic perspective, and to focus on matters of national significance. In the same way that the role of the NTP should not duplicate that of TNSPs, the NTP should not be drawn into the detailed assessment of the merits of individual augmentation projects proposed by TNSPs as part of revenue proposals. This is clearly a matter for the AER as economic regulator.

By its very nature, information and advice from the NTP should relate to matters of strategic, national significance and may be used as one input into the AER's consideration of a TNSP's Revenue Proposal. Such advice is not intended to be and should not be seen as surrogate for the AER's own detailed assessment as to the efficiency and reasonableness of a TNSP's expenditure proposals.

Further, any arrangements established by the Commission should be consistent with the evidentiary matters to which the AER is required to have regard in reaching its decision on a TNSP's Revenue Proposal.

The NTNDP would inform the AER's five year revenue cap determinations. However, consistent with COAG's requirements, TNSPs would not be bound by the NTNDP and the AER would not be bound to base its revenue decisions solely on proposals included in the NTNDP. Rather, TNSPs could seek recognition of any proposed investment option as part of the AER's revenue cap regulation process on the basis of current assessment criteria related to whether the investment option is an efficient and prudent way of meeting the TNSPs obligations.

5.3 Consequential changes to Chapter 6A Rules

The Commission seeks comments on:

- *Whether the implementation of the new arrangements will require any consequential amendments to Chapter 6A of the Rules?*

Response:

The Rules should give effect to the direction given by COAG, in particular, that:

- the NTNDP is strategic in nature (implying both a long-term timeframe and high-level degree of detail), will not replace localised transmission planning, bind transmission companies to specific investment decisions or override TNSP performance obligations;
- Accountability for jurisdictional transmission investment, operation and performance will remain with TNSPs;
- The regime must not cause delays to current regulatory approval timeframes for transmission investments;
- The regime must not reduce or adversely impact on the ability for urgent and unforeseen transmission investment to take place; and
- Not bind the AER in its consideration of the revenue requirements of TNSPs.

5.4 Inter Regional Charging Arrangements

The Commission seeks views on:

- *Whether the current arrangements for inter-regional transfers between TNSPs are sufficient to support the co-ordinated development of a national grid?*
- *What would be the best approach to implementing a more formal inter-regional charging mechanism?*

Response:

Whilst ETNOF recognises the merits of a causer pays approach to inter-regional TUOS, it considers that matters relating to the current regulated transmission framework fall outside the scope and role of the national transmission planning arrangements determined by COAG. ETNOF notes that the Commission undertook extensive consultation with market participants in the review of Pricing of Prescribed Transmission Services and the subsequent publication of the National Electricity Amendment (Pricing of Prescribed Transmission Services) Rule 2006 No.22 on 21 December 2006. In any event, this is a matter for the relevant jurisdictions.

As the revenue regulation framework for electricity transmission businesses does not reduce the revenue available to a TNSP for investments which provide benefits to an adjacent region, there is no serious financial impediment to TNSP investment which delivers benefits across region boundaries. The Commission should assess the materiality of this perceived problem compared to the potential solution prior to considering this matter further.

In addition, ETNOF notes that any change to pricing arrangements would need to encompass a six year implementation timeline as TNSPs cycle through revenue determinations and have their individual pricing methodologies approved.

Chapter 6 Governance Arrangements

6.4 Framework for determining good governance arrangements for the NTP

6.4.3 Facilitating the best governance structure for the NTP

6.4.3.1 Form/composition

The Commission seeks comments on:

- *An appropriate form and composition for the NTP to carry out its functions; and*
- *How board/committee/panel members and office holders should be appointed and for how long.*

Response:

There are 2 factors which significantly influence the form and composition of the NTP:

- The requirements of the COAG decision; and
- The nature and extent of the functions to be undertaken by the NTP.

The COAG decision clearly states that the NTP is to be "*located within the AEMO*". The Issues Paper picks up on this point and (rightly) makes the distinction between AEMO itself (and its Board and management) and the NTP as a separate body within the AEMO, requiring both:

- a sufficient level of independence from AEMO management (noting that there may be conflicts of interests and resources between the NTP and the operational functions of AEMO); and
- transparency and accountability in its own NTP processes.

In order to meet the requirements of the COAG Decision, it would seem that the NTP must be either a business unit or division of AEMO or some form of administrative body operating within (or under the auspices) of AEMO. In either case ETNOF considers the NTP must have a sufficient level of independence, transparency and accountability which should be mandated under specific provisions in the NEL or Rules.

As a practical matter (as recognised by the Commission in the Issues Paper), the nature and extent of the functions to be undertaken by the NTP will necessarily directly impact on:

- the size, structure and resources required by the NTP; and
- the extent to which these need to be separately provided for the NTP as a distinct administrative body operating within the AEMO.

The COAG decision clearly contemplates that the NTP's main function will be to develop (annually) a strategic, longer term NTNDP which will not replace local transmission planning. Both local transmission planning and specific transmission investment decisions will be left to TNSPs. Furthermore, the new NTNDP (together with the continued local planning) must not result in it taking any longer to gain regulatory approval for a new transmission investment than it does currently.

Accordingly, under ETNOF's proposal, the nature and extent of the functions of the NTP (while strategically very important) will be fairly high level, focussing on strategic, long term national transmission development scenarios. This would not require substantial detailed analysis of detailed options and potential solutions (such as that required for local transmission planning and investment decision making which needs a more robust and detailed application of the Regulatory Test to specific options).

Hence the form and composition of the NTP does not need to cater for the needs of a large administrative body with many and varied detailed functions or a large administrative workload. Rather the form and composition of the NTP just needs to ensure that the NTP:

- has access to the right expertise; and
- operates with a sufficient degree of independence, transparency and accountability,

to properly undertake its high level strategic NTNDP development role.

Establishing the NTP as a business unit/division or an administrative committee/panel within AEMO needs to satisfactorily ensure that:

- the NTP has access to the necessary transmission planning expertise to develop its NTNDP;
- that the NTP can do this with a sufficient level of independence from the day to day system operation and security function of AEMO while still ensuring that AEMO and its Board can ultimately be satisfied that the NTP function (for which AEMO, is ultimately responsible) has been satisfactorily undertaken;
- the NTP appropriately and properly consults with stakeholders in developing the NTNDP; and
- the NTP and AEMO can be held properly accountable against them.

ETNOF therefore suggests that:

- the NTP be established as a separate business unit or division within AEMO with (for example) a dedicated General Manager with access to a small number of AEMO staff available for NTP purposes.
- the AEMO NTP division be allocated resources from AEMO within an annually approved budget set by the AEMO Board with input from stakeholders with expenditure tracked and publicly reported against that budget.

6.4.3.2 Independence

- *The Commission seeks comments on the level of independence required for the NTP to carry out its functions.*

Response:

From a governance perspective ETNOF considers that the NTP will be formally independent as a division within the AEMO.

However, ETNOF expects that the NTP and TNSPs will work effectively together to deliver the desired outcomes from the national planning arrangements as envisaged in the COAG decision.

In particular, in developing any potential solutions for inclusion in the NTNDP, the practicality of being able to implement such solutions must be taken into account. The national planning arrangements will not be advanced if transmission developments are considered to be economic by the NTP but are not actually able to be implemented.

An NTP within AEMO, operating subject to the AEMO Board and in consultation with TNSPs and stakeholders in a public and transparent way as outlined in response to 6.4.3.1 is likely to achieve the desired level of independence.

6.4.3.3 Accountability

- *The Commission seeks comments on appropriate forms of accountability for the development of the NTNDP.*

Response:

ETNOF considers the NTP form and processes outlined in all responses to chapter 6 matters provide the basis of a good accountability regime within which the NTP should operate. ETNOF considers that all of the requirements set out in these responses should be mandated in the Rules.

As outlined in 6.5, ETNOF considers the NTP should have a separate budget set annually by the AEMO Board with input from stakeholders. Expenditure against that budget would be publicly reported.

6.4.3.4 Relationship / context with other organizations

- *What should be the consultation arrangements between the relevant stakeholders and the NTP. Should these consultation arrangements be documented in the NER or another instrument?*

Response:

ETNOF considers an NTNDP development process should be included in the Rules which requires:

1. The AEMO NTP division to prepare a preliminary draft NTNDP covering specific matters to be set out in the Rules (reflecting the content of the NTNDP).
2. That preliminary draft NTNDP to be submitted to the AEMO Board and each TNSP who may each provide written submissions to the NTP division as to any changes they suggest.
3. AEMO NTP division to either incorporate changes requested or provide written reasons why they have not been incorporated.
4. The amended draft NTNDP (plus any written reasons against changes suggested by the AEMO Board or TNSPs) to then be published by the AEMO NTP Division with a call for submissions from the public. The AEMO NTP division may also set down a public consultation forum.
5. Final draft NTNDP presented to AEMO Board following close of public consultation. The AEMO NTP division to prepare a final draft NTNDP plus final report on public consultation process (summarising and responding to submissions received and giving reasons for any further changes) to be published and presented to the AEMO Board.
6. AEMO to adopt (or amend) and publish the final NTNDP, including NTP's consideration of the submissions received.

6.5 Funding

The Commission seeks comments on:

- *Should the NTP have a separate budget and accounting requirement?*
- *As the contemplated NTP functions deal with electricity transmission only, should gas market participants also contribute to the NTP's costs?*

Response:

ETNOF considers that the NTP division budget should be set each year by AEMO and recovered through NEM participant fees as part of AEMO's budgeted expenditure. The setting of the budget should involve stakeholder consultation and actual expenditure against that budget made publicly available. In this way participants can more effectively participate in the setting of AEMO participant fees that will now be incurred to support the new NTP function.

Gas market participants should only contribute to NTP costs if the NTP takes on gas transmission planning as well.

Chapter 7 Implementation and Transition Issues

7.1 Enabling Powers for NTP

The Commission seeks views on:

- *The appropriate balance between NEL and NER for defining the NTP's role and functions; and*
- *Should the NTP functions be subject to the Rule Change Process.*

Response:

The core role and functions of the NTP, being to prepare and publish the NTNDP on an annual basis, should be set out in the NEL, and therefore would not be subject to the Rule Change Process.

The NEL should concisely and accurately reflect the policy requirements of COAG and the MCE that the NTNDP requires consultation with relevant stakeholders, have a minimum outlook period of ten years and be updated on an annual basis. The NEL should also clearly set out that the NTNDP is an informational document and does not substitute for normal standards of investigation and analysis such as that performed by the AER in making a revenue decision or by TNSPs in making investment decisions.

The NER would then set out the detailed mechanics of NTNDP development such as publication date, details of consultation procedures and method of funding.

This view is based on ETNOF's proposed national transmission planning arrangements. The detailed structure of what is in the NEL and NER should be further considered once the model for the arrangements is known. This can form part of the detailed implementation plan as necessary and could be considered by the reference group the Commission has flagged it will form. ETNOF reserves its position to provide further input on this matter once the high level model is established.

7.1.1 Information Powers

- *Whether, and if so how and where, should the information requirements of the NTP be defined?*
- *What, if any, powers should the NTP have to request or require information? And what obligations should parties have in respect of any such requests or requirements? Where should these rights and obligations be defined?*
- *What should the relationship be between information held by AEMO and information available for use by the NTP?*

Response:

The information requirements of the NTP are linked to the functions of the NTP and the scope of the NTNDP. As such the information requirements ought to be defined within the National Electricity Law as those necessary to achieve these functions, together with the definition of NTP functions and the scope of the NTNDP.

The NTP powers to request or require information need to be defined in the National Electricity Law as those necessary to carry its functions and deliver the required NTNDP. The detailed specification to give effect to this requirement could be included in the Rules.

Under ETNOF's proposed model the identification of potentially economic transmission developments would depend on a assessment of various demand forecasts and generation development scenarios over a 5 to 15 or 20 year time horizon. Such assessments would require information on transmission and generation costs for a range of fuel types, as well as information on performance characteristics of various generation and transmission development options. Much of this would be at a strategic level and could be sourced from public domain material and expert consultants. Specific technical information on the existing gas and electricity systems would be generally available from AEMO in its role as market and system operator.

Under this model then, the NTP would need some powers to obtain information from a relatively wide range of sources. However, the extent of these powers would not be excessive given that the strategic nature of its assessments.

It is worth noting that TNSPs have an interest in the NTNDP being robust, practical and credible. Hence, TNSPs have an incentive to provide information through the consultation phase to ensure this outcome. ETNOF does not envisage a requirement for the NTP to compel the provision of information, except perhaps for a base level of demand forecasting.

ETNOF reserves its position to provide further input on this matter once the high level model is established.

7.1.2 First Publication Date for NTNDP

The Commission seeks views on:

- *The appropriate first publication date for NTNDP; and*
- *The appropriate approach to developing the first NTNDP and What level of industry consultation should be allowed.*

Response:

ETNOF considers it important to establish the credibility of the NTNDP from the outset and for this reason the first NTNDP should be as complete and comprehensive as possible. ETNOF supports the first NTNDP being published in 2010 after the NTP has been established and has had sufficient time to properly consider the requirements of the NTNDP. This will require the existing planning documents to continue to be produced in 2009.

7.1.3 Advisory Panels

The Commission seeks views on:

- *Should the NTP have the ability under the Rules to establish advisory panels? And what should the status/transparency of such panels be?*

Response:

For the NTP to be effective in replacing the existing IRPC, ETNOF believes there is a need for a formal, standing advisory committee, to assist the NTP (ie a National Transmission Planning Committee). ETNOF considers that only this highest level needs to be formalised in the NER. Ad-hoc working groups can be formed to examine specific matters as and when the needs arise as they do currently between TNSPs, JPBs and NEMMCO. A number of groups already exist and their scope of work changes on a regular basis to reflect changing needs and priorities. To ensure flexibility of response these groups should be the responsibility of the National Transmission Planning Committee, who will set their Terms of Reference etc.

7.2 Transition Issues

7.2.1 National Transmission Planning Function

The Commission seeks view on:

- *What are the main reasons why a ‘hard’ cut-over to the new arrangements might not be feasible, or otherwise appropriate?*
- *What specific transitional measures might be required to resolve any such difficulties with a ‘hard’ cut-over to the new arrangements?*

Response:

ETNOF’s response to 7.1.2 supported the first NTNDP to be published in 2010, with existing planning documents still produced in 2009.

7.2.2 Revised Project Assessment and Consultation Process

The Commission seeks view on:

- *What are the reasons why transition from the current Regulatory Test to a new Regulatory Investment Test might require explicit management?*
- *What issues would need to be provided for in such a transition plan?*

Response:

Transitions from one version of the Regulatory Test to another require explicit management as TNSPs may be part way through investigation and consultation processes when a change is made. In these circumstances, ETNOF considers the TNSP should be able to continue to work with the previous version of the Regulatory Test and not be required to re-commence the process. To require a restart of the process would introduce unnecessary delays, contrary to the COAG directive.

Because the changes being envisaged to the Regulatory Test provide for a combining of the two limbs ETNOF considers it would be appropriate in these circumstances to permit, but not require, a TNSP to adopt the new formulation of the Regulatory Test for a project which is under assessment at the time of introduction of the new RIT. In this situation the TNSP would restart the consultation process using the new RIT. However the TNSP should remain free to continue any processes already in train using the current version if desired.

Chapter 8 Illustrative models for a National Transmission Planner

The Commission would welcome submissions in respect of these illustrative models (set out in Table 8.1 on page 91 of the Paper) and any relevant variants or alternatives (including hybrids formed of different aspects of the illustrative models), with reference to the criteria discussed in Chapter 1:

- *Consistency with the specific wording of, and the broad intent underpinning, the direction provided by the MCE to the Commission in its letter of 3 July 2007;*
- *Solutions which are proportionate to the materiality of the problems being addressed;*
- *Application of good regulatory practice and design;*
- *Application of effective corporate governance and accountability principles; and*
- *Minimisation of implementation costs and risks – including costs associated with any duplication of functions.*

Response:

ETNOF's submission sets out an alternative model ("Model 5") in the same terms as models 1 – 4 proposed in the Issues Paper. ETNOF submits that its proposed model meets the COAG directive and better balances the criteria adopted by the Commission for the purpose of this review.