17 April 2009

Mr John Tamblyn
Chairman
Australian Energy Markets Commission
PO Box A2449
Sydney South NSW 1235

Dear Mr Tamblyn

Review of National Framework for Electricity Distribution Network Planning and Expansion (EPR0015)

Integral Energy fully supports the Commission conducting a thorough and detailed review into the current electricity distribution network planning and expansion arrangements in the National Electricity Market and proposing recommendations to assist in the establishment of a national framework for distribution planning and expansion.

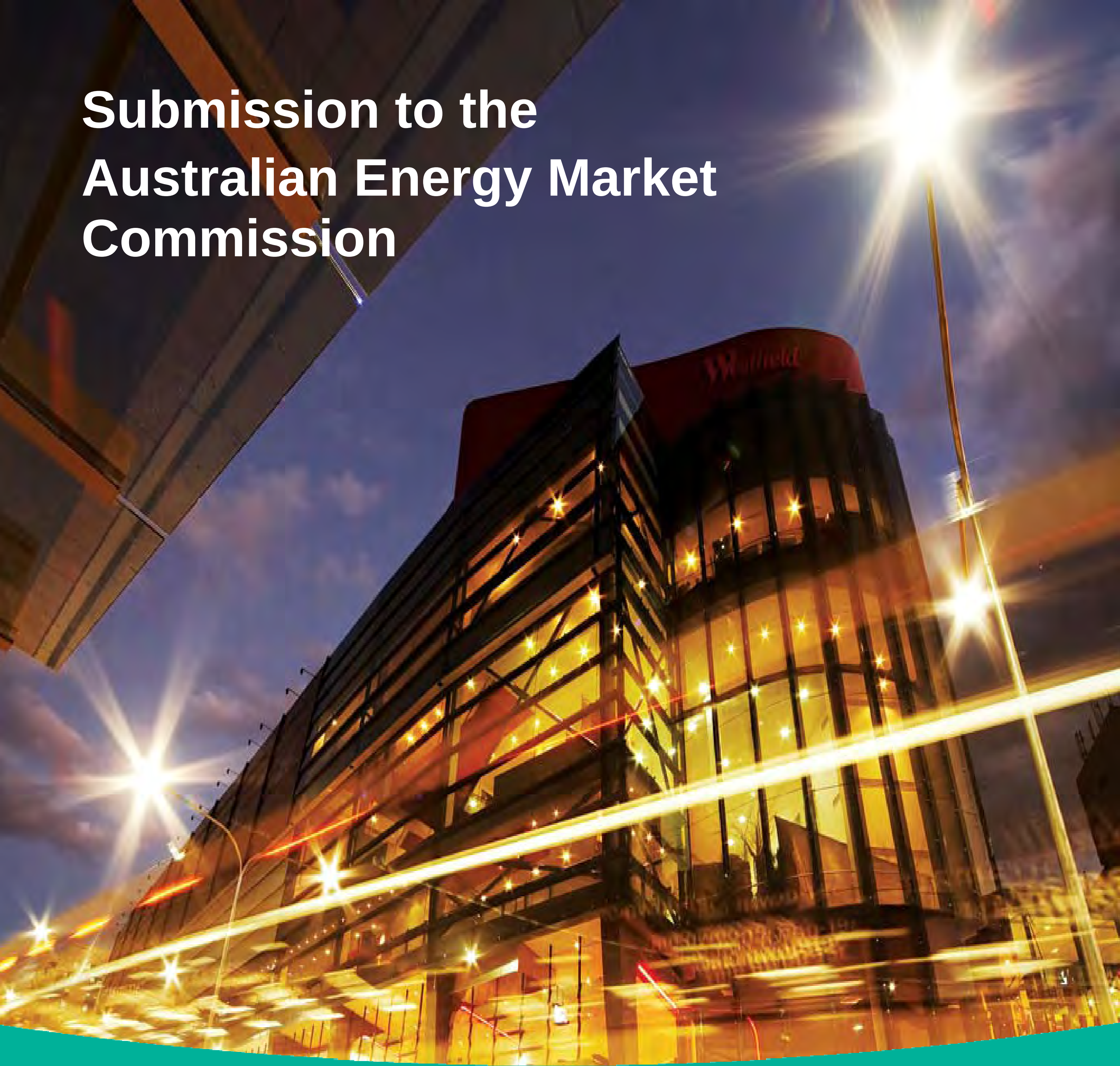
Integral Energy recognises that the Scoping and Issues Paper released by the Commission is the initial phase of the review and that Integral Energy will have the opportunity to provide further input into the review at the industry workshops scheduled for May 2009 and to provide comment on the draft report and rules scheduled for release in June 2009.

Attached is Integral Energy's submission in response to the Commission's Scoping and Issues Paper. Our comments focus on the need to ensure consistency with the transmission arrangements and to provide details of the processes currently in use in NSW.

If you have any queries regarding this submission please do not hesitate to contact our Manager Regulatory & Pricing, Mr Mike Martinson on (02) 9853 4375.

Sincerely

Vince Graham
Chief Executive Officer



Submission to the Australian Energy Market Commission

Review of National Framework for Electricity Distribution Network Planning and Expansion

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INTEGRAL energy

The power is in your hands

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Requests and enquiries concerning this document should be addressed to:

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Front Cover:

Parramatta by night, supported by
Integral Energy's Parramatta Field Service Centre.

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Introduction

The Australian Energy Market Commission (AEMC) has been directed by the Ministerial Council on Energy (MCE) to conduct a review into the current electricity distribution network planning and expansion arrangements in the National Electricity Market with the view to establishing a national framework for distribution planning and expansion.

The AEMC has released a Scoping and Issues Paper which commences the initial phase of the review and is seeking comment on the scope of the review and to identify and seek views on a range of issues that require resolution in recommending a national framework.

Integral Energy supports the terms of reference for the review, particularly the characteristics of a national framework which should ensure that:

- DNSPs have a clearly defined and efficient planning process which provides certainty in relation to the approval of network expansion and augmentation to maintain the reliability of supply to customers;
- DNSPs develop the network efficiently;
- There is a level playing field for all regions in terms of attracting investment and promoting more efficient decisions;
- There is an appropriate information transparency; and
- The regulatory compliance burden is not onerous.

Integral Energy is also keen to ensure that there is consistency in approach and methodology between transmission and distribution planning wherever possible.

2

Scope and AEMC proposed approach

The Commission is seeking stakeholder views on:

1. The proposed scope for the review;
2. Its proposed approach and assessment criteria for the review; and
3. The interaction between transmission and distribution network planning.

2.1 The proposed scope for the review

Integral Energy notes that the AEMC review will not cover those distribution network connections and access issues which are being separately addressed by the MCE through the planning and connection process.

Integral Energy supports the AEMC's view that issues relating to the framework governing revenue determinations, pricing of distribution services and the recovery of network investment are not within the scope of the review.

Scope of distribution services

The AEMC has asked whether the scope of the national framework should be extended beyond the direct control, standard control services as defined in the National Electricity Rules, to include negotiated distribution services and direct control, alternate control services. For consistency in the approach to the planning of the distribution network, Integral Energy believes that it is essential that the scope of distribution services to be covered by the AEMC's review should align with the Australian Energy Regulator's (AER's) classification of services as part of the current distribution determination process.

In this regard, Integral Energy believes that the review should be confined to direct control, standard control services. For Integral Energy, the AER has determined that the only direct control, alternative control service is public lighting and the AEMC's review would have little if any relevance to the provision of public lighting services.

The concept of negotiated services for distribution businesses is not a well understood term. In fact it is difficult to understand what, if any service provided by a DNSP relating to access to the network would be anything other than a direct control, standard control service. To add to the confusion around a negotiated distribution service is the concept of negotiated components of a direct control, standard control service. In conjunction with the AER, Integral Energy and the other NSW DNSPs have spent a considerable amount of time trying to define these services as part of the current distribution determination process. It would appear that the provision of these negotiated components of the direct control, standard control services would generally be covered by the MCE connection process review and as such would be outside the scope of the AEMC's review.

In the absence of a more transparent service definition framework, the scope of the review should be confined to direct control, standard control services. In essence broadening the scope will only complicate an already complex review.

Integral Energy considers that the review should be confined to direct control, standard control services.

2.2 Proposed approach and assessment criteria for the review

In addition to the requirement to have regard to the National Electricity Objective in the National Electricity Law, the AEMC have proposed the following decision making criteria for the review:

- The extent to which the proposed national framework incorporates the variations in the existing jurisdictional distribution planning arrangements, including how well the framework is able to accommodate variations in jurisdictional reliability standards;
- An appropriate balance between the regulatory burden on DNSPs and the benefits to the broader market;
- Ensuring a level playing field for all regions in terms of attracting investment and promoting more efficient decisions;
- Minimising the regulatory compliance burden for market participants operating in more than one region in the NEM;
- The effectiveness of the proposed annual planning process and annual planning report in identifying non-network solutions to augmentations and encouraging efficient planning by market participants;
- Access to and timeliness of the dispute resolution process; and
- Achieving consistency, to the extent appropriate, between the national framework for distribution planning and the electricity transmission planning framework.

Integral Energy supports the decision making criteria for the review listed by the AEMC in the Scoping and Issues Paper. However, Integral Energy notes that, as part of the characteristics of a national framework detailed above, DNSPs should have a clearly defined and efficient planning process. Given this desirable outcome it would be appropriate for the decision making criteria to also reflect a measure of efficiency such that any tradeoffs made in developing the national framework deliver the most efficient outcomes.

2.3 The interaction between transmission and distribution network planning

Whilst recognising the differences that exist between transmission and distribution, Integral Energy believes that it is critical that there be a consistent approach to assessing investment options for addressing network constraints.

The framework for planning needs to ensure that the outcome for either a distribution or transmission investment option is determined by the least community cost solution and not as a result of having two different regimes for transmission and distribution.

With regard to the regulatory investment test for distribution, Integral Energy believes that it is appropriate and consistent for the thresholds in the regulatory investment test – transmission to apply to distribution.

3

Annual planning requirements

The MCE has agreed that the national distribution planning framework should require DNSPs to conduct an annual planning process covering a 5 year forward looking period and produce an annual planning report which would be publicly available and would, at a minimum, set out the forecast distribution network constraint information. In the Scoping and Issues Paper, the Commission is seeking stakeholder comment on aspects of the planning report requirements.

The Commission is seeking comments on the scope of the planning and reporting process. In particular:

4. In addition to emerging constraints, what other types of potential problems of the distribution network should be included in annual planning reports?

5. How could the interaction between transmission and distribution planning be reflected in the annual planning and reporting process?

6. Should the annual planning report including reporting on work carried out by DNSPs including reporting of actual network performance information and historical data?

3.1 What other types of potential problems of the distribution network should be included in annual planning reports?

Integral Energy believes that the information provided in DNSPs Annual Planning Reports (APRs) should be consistent with that provided in the TNSPs planning statements. Integral believes that the APR should contain the information detailed in Integral Energy's Electricity System Development Review (ESDR) which is in accordance with information disclosure protocols under the NSW Demand Management Code of Practice. To be consistent with requirements for the TNSP APRs Integral Energy also believes that it would be appropriate for information to be provided on all proposed replacement projects over $5 million in the DNSP APR. The information provided should align with the NER requirements for TNSPs.

The benefit of providing information on replacement projects is for transparency reasons only. The replacement expenditure is subject to significant review by the AER and its consultants and to public consultation at the time of the revenue determinations and the AER then decides on the efficient level of replacement expenditure appropriate for each DNSP. Integral Energy does not believe that it would be appropriate for the replacement expenditure to be subject to further review and public consultation during the relevant regulatory control period as part of an annual planning reporting process.

3.2 How could the interaction between transmission and distribution planning be reflected in the annual planning and reporting process?

Integral Energy and TransGrid, the transmission network service provider in NSW, conduct regular joint planning reviews. Integral Energy believes that it would be appropriate for the outcomes of the joint planning reviews to be reported in the APRs for each business.

In order for the two reports to align it would require the reporting thresholds for transmission and distribution to align as well. It would be confusing and counter productive if these reporting thresholds were different.

Integral Energy would suggest that the distribution APR should be published by 30 June each year.

3.3 Should the annual planning report include reporting on work carried out by DNSPs including reporting of actual network performance information and historical data?

Integral Energy currently publishes an annual Electricity Network Performance Report (ENPR). The report is prepared in accordance with the Electricity supply (Safety and Network Management) regulation 2002 and documents Integral Energy's performance with respect to:

- Network management;
- Customer installation safety;
- Public electrical safety awareness; and
- Bush fire risk management.

As part of the network management section the document details performance against the NSW design, reliability and performance (DRP) Licence Conditions as well as reliability, quality of supply, complaints etc.

Integral Energy will also be required to report the network performance statistics to the AER under the 2009 to 2014 distribution determination.

It is difficult to understand what benefit, if any, would come from reporting the network performance data a third time as part of an annual planning report, particularly if the definitions and reporting periods are not consistent. Depending on the timing of the publication of the APR the data reported may be at least 12 months old and its relevance to investment decisions would be minimal.

Integral Energy considers that the APR should not include reporting on work carried out and actual performance information and historical data as this reporting is already undertaken through separate processes.

3.4 What should be the type and level of detail of information to be provided in the planning report?

The AEMC is seeking comments on the appropriate content of the annual planning report, and especially on:

7. What factors need to be considered to ensure the level of detail of the information provided is useful and appropriate to stakeholders?

8. For the areas that are to be reported on, what specific factors should be considered? For example for emerging constraints, how should emerging constraints be classified and how could they be consistently set out?

9. Should a distinction be made between general information that is publicly available and more detailed information for embedded generators and demand side response proponents?

The AEMC have suggested that the APR contents could include such things as:

- Credible scenarios of demand for the next five years;
- Forecast distribution network constraints and other distribution problems;
- Potential solutions to network constraints including results of case-by-case project assessments and public consultations where applicable;
- Information on projects that were not subject to the project assessment process that have been scheduled or are proposed;
- Forecast of distribution network capacity including load forecasts and transmission interface provisions; and
- Other factors such as the adequacy of transmission interchange capacity, general network capacity and summer and winter peak capacity.

The main focus of the proposed information requirements appears to be on network constraints. Integral energy agrees that providing information in the APR on demand-related constraints and growth forecasts is appropriate. However, the planning framework needs to specify the (planning) criterion that is applied to define a need for investment as a "constraint" for example the NSW Design, Reliability and Performance (NSW DRP) licence conditions.

It should be recognised that investment is not always constraint driven. Investment needs are often a result of other drivers such as safety, duty of care, reliability, customer connections, asset condition or a combination of all of these. These drivers are often a consequence of a regulatory obligation or requirement.

Integral Energy currently publishes an Annual Planning Statement (APS) or Electricity System Development Review (ESDR). This document sets out the network strategy, energy efficient solutions both planned and underway and the future expenditure plans. The ESDR contains all the information required by external stakeholders to evaluate network constraints and identify non-network alternatives and is in line with the disclosure protocol in the current NSW electricity industry Demand Management Code of Practice.

The APS is structured to:

- Provide details and information on network constraint areas over the next ten years in accordance with the Demand Management Code of Practice;
- Invite stakeholder input and feedback, particularly in relation to suggesting alternative proposals to relieving specific network constraints;
- Outlines actions taken and results achieved as a result of feedback received since the last Planing Statement was issued;
- Explains Integral Energy's energy efficiency strategy.

3.5 What factors need to be considered to ensure the level of detail of the information provided is useful and appropriate to stakeholders?

The NSW Demand Management Code of Practice details the necessary information disclosure requirements to inform the market in a timely manner and to ensure that the information is provided in a clear and consistent form without wasting effort in providing unnecessary information.

The disclosure protocol requires two levels of information to be disclosed annually:

- A low level of detail across the whole network to provide an indication of where constraints are, and are not, likely to emerge in the foreseeable future; and
- A medium level of detail for parts of the network where a constraint is forecast within five years to allow customers and third parties to consider whether they may be able to assist in addressing the constraint.

Integral Energy publishes this information in its ESDR.

The ESDR is published annually by 31 May each year and the information published in the ESDR is also provided to NEMMCO for compiling the Annual Statement of Opportunities.

The ESDR provides information on all sub-transmission and zone substations and lower voltage parts of the network where significant network support expenditure is anticipated. A description of the basis for formulating load forecasts and the system planning guidelines is also provided as well as the following information on all zone substations:

- Total capacity;
- Firm delivery capacity;
- Peak load;
- Whether a constraint is forecast within five years; and
- A brief description of trends and factors driving any identified constraints.

Integral Energy would support a continuation of the disclosure protocols detailed in the NSW Demand Management Code of Practice.

3.6 For the areas that are to be reported on, what specific factors should be considered? For example for emerging constraints, how should emerging constraints be classified and how could they be consistently set out?

The NSW Demand Management Code of Practice outlines the information disclosure requirements for zone substations where a system constraint is forecast to occur within five years.

The system is considered to be constrained in those locations where the existing load or forecast load requirements are such that the NSW DRP Licence Conditions are not or will not be met based on the forecast loads.

The information to be provided on the constrained zone substations in the network includes:

- Total capacity, firm delivery capacity and peak load;
- The extent, frequency and length of any overloads;
- The power factor at the time of peak load;
- The specific security standard that applies;
- The nature of the load at the time of peak or constraint;
- A brief description of possible system support options for overcoming the constraint and their estimated total cost and/or annualised cost;
- A forecast date that electricity support investment decisions must be made;
- A statement as to whether a Request for Proposals will be issued based on a Reasonableness Test; and
- An outline of how the DNSP intends to inform and test the market.

Integral Energy would support a continuation of these disclosure requirements.

3.7 Should a distinction be made between general information that is publicly available and more detailed information for embedded generators and demand side response proponents?

Integral Energy believes that if the information disclosure protocol, as outlined in the NSW Demand Management Code of Practice, is followed that it would not be necessary to distinguish between general information and the more detailed information for embedded generators and demand side response proponents.

The intent of the ESDR is to inform all stakeholders of emerging constraints. Any more detailed information on a particular constraint would be provided as part of any Request for Proposal or if an embedded generator or demand side response proponent approached Integral Energy with a possible solution to a constraint identified in the ESDR.

3.8 How should the planning and reporting process be implemented?

The AEMC is seeking comments on the implementation of the planning and reporting process. In particular:

10. Would the Australian Energy Market Operator's website be the appropriate central location for the planning reports to be stored and published?

11. What would be the appropriate timeframe for the publication of the DNSP annual planning report (noting the relationship between the timeframe for the publication of the TNSP annual planning report and the DNSP/TNSP joint planning requirements)?

3.8.1 Would the Australian Energy Market Operator's website be the appropriate central location for the planning reports to be stored and published?

Integral Energy consider that it should publish the APR on its website and that it is appropriate to provide a link to the APR from a central location to Integral Energy's website. The Australian Energy Market Operator's website would seem the most appropriate location to provide this link.

3.8.2 What would be the appropriate timeframe for the publication of the DNSP annual planning report (noting the relationship between the timeframe for the publication of the TNSP annual planning report and the DNSP/TNSP joint planning requirements)?

Integral Energy currently publishes the ESDR by 31 May each year however, Integral Energy considers that it would be appropriate to synchronise the publication of the transmission and distribution APRs.

4

Project assessment and consultation process

The Commission is seeking comments on the following elements to the project assessment framework:

4.1 Threshold to trigger project assessment

The Commission is seeking comments on the design of the project assessment process. In particular:

12. What types of investments should be subject to the project assessment process?

13. What are the appropriate thresholds to trigger the project assessment process?

14. Should the thresholds be indexed in accordance with the CPI or subject to a periodic review?

4.1.1 What types of investments should be subject to the project assessment process?

The NER, as currently drafted, require DNSPs to carry out an economic cost effectiveness analysis of possible options for augmentation of the network exceeding $1 million. Also, the current regulatory test requires consideration of “market benefits” in the analysis process for augmentation investments driven by reasons other than meeting a regulatory obligation or requirement.

As stated earlier, in the absence of a more transparent service definition framework, the scope of the AEMC review should be confined to direct control, standard control services and negotiated services should be considered outside the scope of the AEMC review.

For consistency with the arrangements for transmission, distribution projects should be classified by the original intent of the augmentation, that is, if there is a need to augment to relieve a distribution constraint which ultimately causes a transmission augmentation, then the project would be assessed purely under the distribution process and dual function assets should be assessed under the distribution process.

4.1.2 What are the appropriate thresholds to trigger the project assessment process?

Integral Energy considers that the thresholds should be same for both transmission and distribution. That is, a cost threshold of $5 million for new small distribution network assets and a cost threshold of $20 million for new large transmission network assets.

4.1.3 Should the thresholds be indexed in accordance with the CPI or subject to a periodic review?

The thresholds, once aligned with the thresholds for transmission assets, should be indexed using the same methodology and timeframe as that applicable to the transmission thresholds.

4.2 What are the requirements for identifying and consulting upon the range of options?

The Commission is seeking stakeholder comments on the RFP process. In particular:

> 15. What factors should be considered in a RFP process and how should this be specified in the Rules compared to AER guidelines? Including:
>
> - what defines a credible option?
> - what information is needed to enable market participants to raise alternatives?
> - how long should the consultation take place?
> - should an RFP process include elements to deal with the potential issue of DNSPs seeking assurance from non-network proponents for the performance of a non-network option?

Integral Energy has adopted the RFP process outlined in the NSW Demand Management Code of Practice. Under this Code of Practice, Integral Energy will decide if it is reasonable to issue a formal RFP or other direct approach to the market for electricity system support where the system constraint meets the following criteria:

- The expected overloading is sufficient to require investment in system support to meet the NSW DRP Licence Conditions; and
- The estimated forecast annualise cost of adequate system support is at least $200,000 for at least one year.

A RFP may be issued for constraints of smaller size and cost than this subject to consideration of the following matters:

- Any relevant information or proposals submitted by interested parties;
- The significance of the constraint or of possible system support options to the local or wider community.

Where it does not issue a formal RFP, Integral Energy is required to explain why and demonstrate how it has undertaken fair and reasonable steps to allow non-network based solutions to develop and to service the market.

When issuing a formal RFP Integral Energy is required to:

- Advise all registered interested parties of the release of the RFP;
- Publicly advertise the release of the RFP;

- Issue the RFP at least eight months prior to the forecast date that the system support investment decision will be made; and
- Allow eight weeks for submission of proposals.

Apart from an update of the information already provided in the ESDR the RFP is to include the following information:

- The level/timing of network support required;
- The results/reports from any investigations and negotiations with customers;
- Load data for the largest existing commercial/industrial customers where applicable and where customer consent is provided;
- Expected load contributions by new loads per year where applicable; and
- All relevant assumptions to be used in the evaluation of proposals/options.

Integral Energy believes that is it prudent to seek an assurance from non-network proponents for the performance of a non-network option and may require the proponent to provide information and other data on other sites where the proposed solution has been implemented.

Integral Energy's experience is that the RFP process in the NSW Demand Management Code of Practice works reasonably well as the Reasonableness Test allows the exclusion of those projects where a non-network solution either would not be workable or appropriate. Integral Energy does not believe that a prescriptive requirement for a RFP process for all projects over a certain expenditure threshold without a Reasonableness Test would lead to any more useful and cost effective non-network solutions than are currently realised through the RFP process under the NSW Demand Management Code of Practice. The imposition of a prescriptive requirement for a RFP process without a Reasonableness Test will only add costs without any realisable benefits.

4.3 What costs and benefits should be recognised and quantified in the assessment?

The Commission is seeking stakeholder comments on the application of the project assessment process. In particular:

16. What is the appropriate list of costs and benefits associated with distribution projects, and should that list be mandated in the NER?

17. How should the range of benefits to be quantified under the project assessment process be determined?

18. How can the project assessment process ensure that environmental benefits are appropriately treated and quantified?

Integral Energy undertakes a financial assessment of each capital expenditure project in accordance with the *NSW Government Office of Financial Management TPP07-4 Commercial Policy Framework Guidelines for Financial Appraisal July 2007.*

In many cases network capital expenditure will be necessary to meet criteria that are defined within licence, legislative or regulatory conditions. In these cases, the costs will be readily apparent, but the financial benefits may not. Therefore, the financial analysis of a project will determine the least present value of costs to meet the particular criteria being addressed.

4.3.1 What is the appropriate list of costs and benefits associated with distribution projects, and should that list be mandated in the NER?

It is important to provide a manageable process which does not involve significant costs, trying to identify benefits which do not exist.

The most easily quantifiable benefit obtained from network augmentation projects is the ability to service load in accordance with specified security standards. An approximate revenue stream associated with this additional load may be derived to evaluate the benefits of a particular project option.

4.3.2 How should the range of benefits to be quantified under the project assessment process be determined?

In assessing the benefit of the additional revenue stream that comes from increased capacity Integral Energy uses a ten-year demand forecast. It would seem appropriate to limit the assessment of benefits to no more than ten years.

4.3.3 How can the project assessment process ensure that environmental benefits are appropriately treated and quantified?

Treatment of environmental benefits should continue to be on the basis of costs as mandated by legislation.

Integral Energy considers the inclusion of considerations of underground vs. overhead construction is not seen as appropriate as the “environmental” benefits of underground construction are largely aesthetic and it is not possible to ascribe aesthetic benefits. Any network cost benefits (for example reduced maintenance) will already be included in the assessment of whole of life maintenance costs.

The only real environmental benefit that may be obtained could be a reduction in network losses, particularly for a distributed generation solution. There needs to be some commonly recognised or mandated cost of carbon to enable this to be properly assessed.

4.4 What should be the decision-making criteria used to determine which option passes the test?

The Commission is seeking stakeholder comments on the application of the project assessment process. In particular:

19. How should a net benefit test be designed for distribution investment assessments? What are appropriate circumstances where a least cost assessment should be applied, and if so, should the two limbs of the regulatory test be maintained?

20. Is there a need for a more specific decision making criterion compared to the existing regulatory test?

4.4.1 How should a net benefit test be designed for distribution investments assessments? What are appropriate circumstances where a least cost assessment should be applied, and if so, should the two limbs of the regulatory test be maintained?

The NER, as currently drafted, require DNSPs to carry out an economic cost effectiveness analysis of possible options for augmentation of the network exceeding $1 million. Also, the current regulatory test requires consideration of “market benefits” in the analysis process for augmentation investments driven by reasons other than meeting a regulatory obligation or requirement.

Integral Energy has not had to undertake a market benefit assessment of a project since the commencement of the National Electricity Market. Typically, distribution projects are required to meet regulatory obligations or requirements and hence the investment needs to proceed regardless of any perceived market benefit and all assessments are undertaken on a “least cost” basis.

Integral Energy believes that as most, if not all, of the augmentation investments are driven by the need to meet regulatory obligations or requirements and in the absence of a clear case for the materiality of market benefits there would be little benefit in maintaining the market benefit test in the regulatory test and consideration should be given to excluding the market benefits test from the regulatory test for distribution investment.

4.4.2 Is there a need for a more specific decision making criterion compared to the existing regulatory test?

Integral Energy does not believe there is a need for more specific decision making criterion compared to the existing regulatory test and that the assessment process as currently applied under the regulatory test, whereby DNSPs apply the assessment across a range of scenarios and use judgment to find the most appropriate option, should be maintained in any national framework.

5

Dispute resolution process

The Commission is seeking stakeholder feedback on the following aspects of the proposed dispute resolution process:

5.1 What should be the scope of issues subject to dispute resolution?

The Commission is seeking stakeholder comments on the appropriate scope of the dispute resolution process. In particular:

21. Should the dispute resolution process only apply to project assessments undertaken by DNSPs under the regulatory test or should the dispute resolution process also apply to matters arising from DNSP's annual planning processes?

22. What is the appropriate scale of distribution projects that should be subject to the dispute resolution process? Should the threshold for the dispute resolution process be aligned with the threshold for the project assessment process?

5.1.1 Should the dispute resolution process only apply to project assessments undertaken by DNSPs under the regulatory test or should the dispute resolution process also apply to matters arising from DNSP's annual planning processes?

Integral Energy believes that the dispute resolution process developed for the transmission regulatory investment test should be applied to distribution. Integral Energy does not believe that there should be any extension of the scope for dispute resolution and that the dispute resolution process should only apply to project assessments undertaken by DNSPs under the regulatory test. That is, the dispute resolution process should only cover disputes relating to the DNSP's compliance with the NER and the investment test itself.

To allow disputes to apply to matters arising from the annual planning process would be problematical. The annual planning process is a forward looking process and is intended to provide information to interested parties on the most likely scenarios in terms of the development of the distribution network. The APR is only provided to interested parties for information purposes only and a DNSP should not be held accountable for any decisions made by participants based on the information in the APR.

5.1.2 What is the appropriate scale of distribution projects that should be subject to the dispute resolution process? Should the threshold for the dispute resolution process be aligned with the threshold for the project assessment process?

Integral Energy believes that the threshold for the dispute resolution process should be aligned with the threshold for the project assessment process.

5.2 How should the dispute resolution process operate?

The Commission is seeking stakeholder comment on how the dispute resolution process should operate. In particular:

23. Who should be able to initiate the dispute resolution process?

24. What process should be followed to resolve disputes and what should be the timing for this process? Should parties be required to undertake a formal mediation process before the dispute is referred for a binding determination? What aspects of the proposed process for transmission should apply to distribution?

25. Who should make binding determinations to resolve disputes? Is the AER the most appropriate body? If a mediation process is used, who should be the mediator for disputes?

26. Should the appointed arbiter have the ability to reject disputes immediately if the grounds for the dispute are invalid, misconceived or lacking in substance?

5.2.1 Who should be able to initiate the dispute resolution process?

Integral Energy notes that currently only Registered Participants are able to lodge a dispute in relation to distribution unlike transmission where a range of parties are able to lodge a dispute.

It will be important for the AEMC to consider the type of projects that will be subject to a dispute in determining who the parties are that should be able to initiate a dispute. Given that most, if not all, of Integral Energy's distribution projects are assessed under the reliability limb of the current regulatory test and there have been no assessments under the market benefit limb, it would seem that there was little if any reason for Registered Market Participants to be involved in a dispute

The parties most likely to be interested in a project assessment by a DNSP would be connection applicants and non-network solution providers as these are the parties who would be directly affected by the DNSP planning processes. The connection process is outside the scope of the AEMC review and it is believed that a separate dispute resolution process will be implemented to cover disputes arising from the connection process.

5.2.2 What process should be followed to resolve disputes and what should be the timing for this process? Should parties be required to undertake a formal mediation process before the dispute is referred for a binding determination? What aspects of the proposed process for transmission should apply to distribution?

Integral Energy believes that the dispute resolution process developed for the transmission regulatory investment test should be applied to distribution.

5.2.3 Who should make binding determinations to resolve disputes? Is the AER the most appropriate body? If a mediation process is used, who should be the mediator for disputes?

Integral Energy believes that the dispute resolution process developed for the transmission regulatory investment test should be applied to distribution.

5.2.4 Should the appointed arbiter have the ability to reject disputes immediately if the grounds for the dispute are invalid, misconceived or lacking in substance?

Integral Energy believes that the dispute resolution process developed for the transmission regulatory investment test should be applied to distribution.

5.3 What should be the outcome of the process?

The Commission is seeking stakeholder comment on the appropriate effect of the dispute resolution process. In particular:

27. Should the dispute resolution process be restricted to reviewing the DNSP's compliance with the NER and requiring the DNSP to amend its analysis in its project assessments or annual planning report if it is found that it has not fully complied (i.e. compliance review)? Or, should the dispute resolution process provide for a review of the outcomes of the DNSP's project assessments or annual planning report and if it is found that the DNSP has not reached the best outcomes, direct the DNSP to implement the most suitable outcomes (i.e. merits review)?

As stated earlier, Integral Energy does not believe that there should be any extension of the scope for dispute resolution and that the dispute resolution process should only apply to project assessments undertaken by DNSPs under the regulatory test. That is, the dispute resolution process should only cover disputes relating to the DNSP's compliance with the NER and the investment test itself.

This would mean that the outcome of the dispute resolution process would require the DNSP to amend its analysis in its project assessments or annual planning report.

6

Common issues

The Commission is seeking stakeholder comment on:

28. The appropriate balance of specification in the national framework between the Rules and supporting guidelines. 29. Should “urgent” investments be exempt from aspects of the national framework? If so, how should “urgent” be defined? 30. What consequential amendments should be made to other arrangements to reflect the implementation of the national framework?

6.1 The appropriate balance of specification in the national framework between the Rules and supporting guidelines.

Integral Energy notes that a DNSP cannot initiate a change to a guideline if the guideline is not working or if there are problems with applying the guideline.

Integral Energy believes that the NER should specify the requirements and that the DNSPs are then required to comply with the NER.

6.2 Should “urgent” investments be exempt from aspects of the national framework? If so, how should “urgent” be defined?

There may be augmentation projects which are customer driven and have to meet the timeframes required by the customer. As such they may be “urgent” and if having to comply with the NER planning requirements would substantially delay the project and not meet the customer’s timeframe then there should be an exemption from aspects of the national framework.