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energex
positive energy

Australian Energy Market Commission
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Dear Dr Tamblyn

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

ENERGEX Limited (ENERGEX) welcomes the opportunity to respond to the Australian Energy Market Commission's (Commission) Scoping and Issues Paper titled *Review of National Framework for Electricity Distribution Network Planning and Expansion* (Issues Paper). ENERGEX provides this response as a Distribution Network Service Provider (DNSP) operating in Queensland.

ENERGEX supports the development of a national framework for network planning that delivers a reduction in barriers for non-network alternatives and a distribution specific test for project assessment that recognises reliability as one of the key drivers for distribution investment.

Annexure A to this submission contains ENERGEX's detailed response to the issues raised by the Commission for comment throughout the Issues Paper.

At a high-level, ENERGEX believes that:

- The drivers, project volumes and lead-times for investment differ markedly between Transmission Network Service Providers (TNSPs) and DNSPs. These differences emphasise the importance of establishing a national framework for network planning that is tailored to the requirements of DNSPs and proponents of distribution non-network alternatives. ENERGEX does not believe that a suitable framework can be established for distribution in circumstances where the underlying premise is an alignment of the transmission and distribution frameworks. However, ENERGEX supports the desirability for greater consistency in joint planning activities;

- A single process for analysis and consultation should be applied to joint planning projects between DNSPs and TNSPs. ENERGEX supports the view previously expressed by Grid Australia that a single framework for assessing all options on a consistent basis is required to ensure that the overall most efficient option is selected. ENERGEX believes that the current Regulatory Test should apply to joint planning, to be replaced by the RIT-D once implemented;

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- Preparation of the Annual Planning Report (APR) should not result in an unwarranted cost burden for DNSPs, and ultimately customers. The scope and level of detail required to be included in the APR should be commensurate with the value to its target audience. Consistent with this principle, an alignment of national and jurisdictional reporting requirements will minimise the regulatory compliance burden for DNSPs and ensure that an appropriate balance is achieved between the costs of production and the value of information provision;

- Given the relative immaturity of the market for non-network solutions, such alternatives are more likely to achieve success in circumstances where they are considered at the point of option development by the DNSP (i.e. early in the process of analysis), rather than where they are raised in response to the RIT-D or its consultation processes;

- The reliability and market benefit limbs of the existing Regulatory Test should continue to remain separate under the RIT-D. Distribution augmentations are rarely required for reasons other than reliability and an attempt to amalgamate the limbs in a manner similar to that undertaken for the RIT-T would materially increase the regulatory burden on DNSPs by appearing to require an explicit assessment of market benefits (the range of which has yet to be prescribed) regardless of the driver for investment. Given that, even under an amalgamated test, the vast majority of investments would be expected to ultimately proceed under a 'least cost' approach (following the process of market benefit assessment), it is difficult to see how the amalgamation would optimise the decision making process and promote efficiency for distribution planning; and

- In undertaking its Review and in developing the RIT-D, the Commission should provide increased clarity on the process for option assessment, option quantification and the interaction of expenditure-related definitions. It is hoped that through this process ambiguities that currently exist in the application of the Regulatory Test will be removed, resulting in a cohesive national framework that is applied consistently across participants.

Please do not hesitate to contact Louise Dwyer, Group Manager Regulatory Affairs on 07 3407 4161 should you wish to discuss this submission in any way.

Yours sincerely

Chris Arnold
General Manager Network Performance

Attach.

ANNEXURE A

COMMENTS ON PROPOSED NETWORK PLANNING AND EXPANSION ARRANGEMENTS

The following table contains ENERGEX's detailed comment on the Issues Paper (questions 1 – 30 inclusive).

Question for Comment	ENERGEX Response
Chapter 2: Proposed Scope and Approach	
1. The proposed scope for the Review.	ENERGEX comments that: • The MCE's Terms of Reference contemplate the AEMC undertaking an examination of existing jurisdictional network planning and expansion arrangements and the preparation of recommendations to assist in the establishment of a national framework. ENERGEX believes that the AEMC should have regard to existing jurisdictional arrangements when developing its recommendations (including transitional provisions). For example, regard should be had to the content and scope of jurisdictional Network Management Plans or APR 'equivalents' to ensure that DNSPs are not required to derive varying sets of data or publish multiple plans/reports; • While it is agreed that an examination of the framework governing revenue determinations, pricing of distribution services and the recovery of network investment are outside the scope of the AEMC's Review, regard must be had for the impact of the national framework for network planning and expansion on the investment framework applying to DNSPs; and • ENERGEX queries the value in seeking to align the national framework for network planning and expansion with a classification of services under Chapter 6 of the NER that will necessarily vary between DNSPs. ENERGEX believes that the network planning and expansion activities sought to be captured under Chapter 5 of the NER primarily relate to the DNSP's shared network.
2. The Commission's proposed approach and assessment criteria for the Review.	The process by which the AEMC will assess its recommendation against both the National Electricity Objective (NEO) and the decision-making criteria should be clarified. For example, satisfaction of the NEO should carry greater weight than any Review-specific criteria.

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	In relation to the specific decision-making criteria proposed in the Issues Paper, ENERGEX comments that: • Criterion 1 – The Issues Paper appears to be silent on the interaction between the proposed national and jurisdictional arrangements. Duplication in regulatory obligations, including reporting, should be avoided. • Criterion 2 – ENERGEX believes that the assessment of regulatory burden versus broader market benefit should be undertaken by reference to discrete areas of regulatory obligation, rather than the framework as a whole. An assessment of the 'national framework' against this criterion may fail to identify opportunities to reduce the regulatory burden. It should also be clarified that in no circumstance should the regulatory burden outweigh the market benefit. • Criterion 3 – It should be recognised that the effectiveness of the national framework in attracting investment and promoting efficient decisions may be influenced by factors outside the scope of Chapter 5 of the National Electricity Rules (NER) (e.g. investment constraints or incentives established at a jurisdictional level). The national framework should seek to establish a 'level paying field' of itself and should not seek to counteract factors that are externally applied. • Criterion 4 – The practical application of this criterion is questionable given that: o the regulatory burden will primarily be borne by DNSPs, who by their nature do not operate within multiple regions; and o DNSPs are not 'market participants' under the NER. It is suggested that this criterion be amended to "Minimising the regulatory compliance burden". • Criterion 7 – ENERGEX does not believe that the inclusion of this decision-making criterion can be justified in light of the range of material differences that exist between transmission and distribution in the conduct of their network planning and investment activities. These differences are highlighted both in the Issues Paper and throughout this submission.
3. The interaction between transmission and distribution network planning.	There are a number of fundamental differences between transmission and distribution. For example: • Distribution augmentations are rarely required for reasons other than reliability – ENERGEX has never undertaken

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	an augmentation based on an assessment of market benefits. Any attempt to amalgamate the reliability and market benefits limbs of the regulatory test in a manner similar to that undertaken for the RIT-T would materially increase the regulatory burden on DNSPs for no clear value; • Although the scale of distribution projects will generally be smaller than transmission projects, they are significantly greater in number. Unless the processes for planning and assessment are streamlined, the regulatory burden on DNSPs will be increased; and • Distribution networks are less 'steady-state' than transmission networks. As a consequence, distribution projects are more likely to be urgent and unforeseen and will generally have shorter lead-times to meet new loads or satisfy regulatory requirements. These differences emphasise the importance of establishing a national framework for network planning and expansion that is tailored to the requirements of DNSPs and project proponents of distribution non-network alternatives. ENERGEX does not believe that a suitable framework can be established for distribution in circumstances where the underlying premise is the alignment of the transmission and distribution frameworks. For example, the scope of 'reliability' as defined in Schedule 5.1 of the NER is not comprehensive enough for DNSP's. The definition was originally tailored for TNSPs and needs to be widened to include voltages down to 11kV and meeting system reliability benchmarks ie SAIDI, SAIFI, CAIDI. In addition, when considering the distinction between distribution and transmission assets, the AEMC should also have regard to the Queensland derogation in NER 9.32.1(b) which provides that: *…transmission network assets are to be taken to include only those assets owned by Powerlink Queensland or any other Transmission Network Service Provider that holds a transmission authority irrespective of the voltage level and does not include any assets owned by a Distribution Network Service Provider whether or not such distribution assets are operated in parallel with the transmission system.*
Chapter 3: Annual Planning Requirements	
4. In addition to emerging constraints, what other type of potential problems of the distribution network should be	ENERGEX considers that the type and level of detail of information to be provided in the APR should be high level and proposes that the APR should contain:

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included in annual planning reports?	• General information on the DNSP's supply network, including the DNSP's operating environment (e.g. growth forecasts); • 5 year forecast of network constraints based on a single 'medium' scenario. Importantly, DNSPs should not be required to prepare forecasts based on low, medium and high scenarios due to the significant compliance cost that this would impose - for ENERGEX, this would effectively triple the existing workload for forecast preparation. Unlike TNSPs who prepare forecasts for a relatively small number of TNIs, DNSPs such as ENERGEX prepare their forecasts down to substation and 11kV feeder level. For ENERGEX, this results in approximately 2,000 forecast points (based on a medium scenario applying a 50 PoE and 10 PoE). There would be a high resource and cost burden and limited demonstrated benefit associated with any requirement for DNSPs to prepare forecasts across multiple scenarios for the purposes of the APR. It should be noted however that ENERGEX does undertake low, medium and high scenario analysis when undertaking individual project assessments under the regulatory test. • 5 year forecast of project scopes and costs. In recognition of the dynamic nature of the distribution planning process, ENERGEX believes that the APR should provide: o detailed planned project scopes and costs for year 1 of the APR, for those projects scheduled for completion in year 1 of a value greater than $1 million. For ENERGEX, this represents approximately 100 – 200 projects per annum; and o strategic project scopes and indicative costs for the remaining 4 years of the APR. These projects represent a preliminary solution for the alleviation of constraints flagged in the APR and as such are scoped and costed at a high-level. • A description of existing and planned demand management programs together with an invitation for non-network solutions, in the form of a statement of network demand management opportunities. It is important to note that although the APR may identify the costs of network solutions for strategic projects (i.e. those flagged for the outer years of 2 – 5), these are preliminary solutions only and are subject to revision should a viable non-network solution be raised. The scope of the APR should be constrained to network augmentations to resolve network security constraints.

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	Network refurbishment and replacement projects should be excluded regardless of the project costs. Reliability projects to improve jurisdictional minimum service standards (SAIDI and SAIFI) should also be excluded from the APR.
5. How could the interaction between transmission and distribution planning be reflected in the annual planning and reporting process?	ENERGEX believes that the APR should flag those projects which have been or are likely to be the subject of joint transmission and distribution planning. Duplication in the information published should also be avoided. For example, the TNSPs' APRs already set out the forecast loads submitted by DNSPs in accordance with NER 5.6.1. An attempt should not be made to duplicate these in the DNSP's APR as the forecasts may have been varied by the TNSP subsequent to their provision, in accordance with NER 5.6.1(d).
6. Should the annual planning report including reporting on work carried out by DNSPs including reporting of actual network performance information and historical data?	Reporting on historic performance or activities under the APR should not be characterised as an assessment of the DNSP's planning 'compliance', as it appears to be suggested by the Issues Paper (at page 16). There are a range of factors, such as high growth and high utilisation that will influence any attempt to undertake a detailed assessment of forecasts against 'performance'. For example, a period of high growth may mean that a project's parameters are revisited and updated prior to project approval. ENERGEX is concerned a requirement to evaluate the robustness of past planning decisions as suggested would require the DNSP to update its previous analysis for factors that are 'now known', imposing considerable cost and complexity. For this reason, ENERGEX believes that historic reporting should take the form of qualitative commentary on the DNSP's performance in the preceding financial year against the APR for that year, for example, by providing information on the implementation of major capital and operating expenditure initiatives. ENERGEX notes that it is the timing of investment delivery against assessed need that is of value to interested parties.
7. What factors need to be considered to ensure the level of detail of the information provided is useful and appropriate to stakeholders?	In determining the level of detail that is required, regard should be had to the relative size or significance of the project, its anticipated value and its operational date. ENERGEX believes that it would be appropriate to establish this requirement in the NER at principle level, rather than attempt to specify detailed information provision requirements. In relation to the specific content requirements of the APR: • The forecast and assessment of constraints should be limited to security constraints on the network (refer to issue

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	8 below); • Information on utilisation should only be required at asset type and utilisation category, not at 'points' in the network; and • ENERGEX queries the value of the inclusion of 5 year forecasts of Distribution Loss Factors (DLFs), suggested by NERA/ACG for inclusion in the APR. Network losses are a complex issue, are only calculated annually and can be influenced by any number of changes in network circumstances over time. A requirement to provide a 5 year forecast of DLFs would represent a significant change for ENERGEX and impose material additional compliance costs. ENERGEX also queries the value of providing this information when the strategic projects that are flagged in the APR may not ultimately proceed, or may proceed in a different form.
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?	ENERGEX believes that emerging constraints should not be classified in a prescriptive manner and instead, should be identified by reference to the high-level factors of network security, reliability and capacity (which may vary by jurisdiction). Emerging constraints should be classified as meeting or not meeting DNSP security planning guidelines / criteria and when the constraint is expected to occur.
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?	ENERGEX does not support a distinction being created between the information that is made available to the general public and that which is made available to potential EG or DSR proponents, through either the annual planning process or the APR. While the APR should provide adequate information to permit the identification of relevant constraints and to scope possible non-network solutions at a high-level, it would simply be impossible for the APR or an alternative document to address all information that may be required by an EG or DSP proponent to fully develop an investment option. ENERGEX is also concerned that this would grant preferential treatment to EG and DSR proponents, pre-empting the outcomes of the planning and RIT-D processes. This may be contrary to the NEO which requires the long term interest of consumers to electricity services to be considered with respect to reliability and service quality and the market design principles which are intended to avoid any special treatment in respect of technologies used by market Participants (NER 3.1.4(a)(3)). However, ENERGEX does strongly support providing additional information on a specific identified constraint to

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	potential EG or DSR proponents upon request following publication of the APR.
10. Would the Australian Energy Market Operator's website be the appropriate central location for the planning reports to be stored and published?	ENERGEX agrees that the AEMO's website would be the appropriate central location for the publication of annual APRs. This would complement the existing practice of publishing regulatory test consultations and decisions on NEMMCO's website.
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)?	ENERGEX believes that the publication date for the APR should be 1 September. ENERGEX does not believe that the APR publication date for DNSPs should be aligned to that applying to TNSPs (i.e. 30 June) on the following basis: • *Summer peaks* - A number of DNSPs (including ENERGEX) are summer peaking. In ENERGEX's case, this summer peak typically occurs in January / February of a given year and forms the basis of its annual forecasts. The summer period ends on 31 March each year and only then can ENERGEX begin the annual planning and forecasting process. Time and resource constraints under a 30 June publication date would necessitate ENERGEX basing its forecasts on the prior year's data, which would be almost 18 months old by the time of APR publication. Although ENERGEX currently provides a draft of its Network Management Plan to its jurisdictional regulator by 30 June, material amendment of the underlying data can occur between the provision of the draft and release of the final on 1 September. This timeframe does not adversely impact publication of Powerlink's APR or joint transmission and distribution planning activities; and • *Forecast volumes* – DNSPs prepare their forecasts on a significantly greater number of data points than TNSPs, necessitating a longer lead-time for forecast and APR preparation. For example, TNSPs will prepare their forecasts at TNI level - for Powerlink Queensland this is approximately 30 – 40 data points. By comparison, ENERGEX prepares its forecasts at both TNI and substation level – representing approximately 250 additional data points. ENERGEX also notes that in circumstances where DNSPs were required to submit the APR to the AER in draft form for approval prior to publication (which is not supported), a delay in publication of 1 to 2 months would be required. ENERGEX suggests that the need for AER approval could be avoided through the inclusion in the APR of a 'statement of compliance' – i.e. a high-level demonstration that the content of the APR satisfies the requirements of the NER and any supporting Guidelines.

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Chapter 4: Project Assessment and Consultation Process	
12. What types of investments should be required to undertake the project assessment process?	Consistent with existing practice, the RIT-D should apply to new distribution assets which are augmentations. Proposed investments such as negotiated services, reconfigurations, reliability and replacement expenditure should be excluded from the project assessment process. Importantly however, there is a need for increased clarity regarding the scope of projects that should be captured within the definition of 'augmentation', e.g. whether this is intended to apply to network communications projects, secondary system projects, land acquisition and conduct installations for future network? With respect to the interaction between distribution and transmission projects, ENERGEX believes that joint projects should be assessed on the basis of the lowest NPV for the joint option under a common regulatory test. ENERGEX supports the view previously expressed by Grid Australia that a single framework for assessing all options on a consistent basis is required to ensure that overall the most efficient option is selected. ENERGEX believes that in joint planning situations the current Regulatory Test should apply until the RIT-D is implemented, recognising that the number of joint distribution and transmission projects that are taken to consultation each year is relatively small (for ENERGEX approximately 1 – 2 per year). ENERGEX also notes that it does not have any 'dual function assets', such that it would need to determine the project assessment process that should be applied (refer to clause 9.32.1(b) of the NER).
13. What are the appropriate thresholds to trigger the project assessment process?	The existing practice of defining triggers in terms of cost thresholds should be retained. ENERGEX believes that: • The threshold for new small distribution assets should be set at $5 million (increased from $1 million); and • The threshold for new large distribution assets should be set at $15 million (increased from $10 million). The practicality of implementing thresholds is a particular issue for Queensland given high load growth and high asset utilisation. This requires ENERGEX to be increasingly responsive in delivering investments to meet customer demand. Setting the thresholds too low is likely to inhibit ENERGEX's ability to build an efficient and secure network in a timely manner. It is important to also note that the threshold will only determine those projects for which a regulatory test is required. Extensive project information, including project scopes and costs, will still be provided to the market through

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	the DNSPs' APRs. In terms of the projects to be captured within the project assessment process, ENERGEX's current approach is to determine if a regulatory test and consultation is required through an assessment of the initial capex cost of the committed projects that form an option. This ensures that where appropriate, multiple 'small' projects are captured within an option for assessment and removes the perceived risk that a DNSP will break an option into smaller components to avoid the threshold.
14. Should the thresholds be indexed in accordance with CPI or subject to a periodic review?	Monetary thresholds should be both indexed in accordance with CPI and subject to a periodic review every 3 years to address circumstances where CPI fails to reflect the escalation in underlying input costs. A failure to increase thresholds over time would increase the regulatory burden on DNSPs in terms of resourcing and costs as the RIT-D will progressively apply to projects that were not intended to be captured at the time that the thresholds were set.
15. What factors should be considered in a RFP process and how should this be specified in the NER 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?	ENERGEX believes that, given the relative immaturity of the market for non-network solutions, such alternatives are more likely to achieve success in circumstances where they are considered at the point of option development by the DNSP (i.e. early in the process of analysis), rather than where they are raised in response to a formal RFP. Further to this, ENERGEX is refining the $/kVA cost of non-network options, to provide a more appropriate 'hurdle rate' for the assessment of non-network solutions. ENERGEX therefore provides only qualified support for the introduction of an RFP process and believes that this should only be applied to projects greater than $15 million (i.e. the proposed revised threshold for new large distribution assets). Although it is accepted that an RFP would provide additional transparency to the planning process, in the absence of a mature market for non-network solutions, the likelihood of the RFP eliciting a viable non-network alternative will be limited. An RFP process for projects below the threshold for new large distribution assets is not supported given the volume of consultations that would be required, the associated regulatory burden and costs for distributors, and the risks of delay to investment delivery. ENERGEX believes that: • The RFP timeframes must recognise the adverse impact of a prolonged evaluation process on the delivery of

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	investment; • To provide assurance on the viability of non-network solutions, the RFP process needs to provide clarity around the materiality/firmness of a proposed solution. For a non-network solution to be a credible option, it has to provide an acceptable level of 'firmness'. In ENERGEX's view, this will occur where it is able to meet the same reliability standards as the DNSP at the point on the network to which it is connected. If the non-network proposal is immature, it may delay the project implementation and impact the ability of the DNSP to comply with its minimum service standards. Consequently, it is unlikely that a DNSP would consider a non-network solution that results in a higher risk of supply interruptions to be a valid alternative solution; and • Responses to the RFP process must comply with both the NER and jurisdictional-specific requirements relating to reliability, security and technical standards. The content of the RFP should be developed and contained in the NER as this is quasi-regulatory in nature and the format of the RFP and the processes supporting its release should be contained in an AER Guideline.
16. What is the appropriate list of costs and benefits associated with distribution projects, and should that list be mandated in the NER?	ENERGEX does not believe that it is necessary to mandate a list of potential costs and benefits. However, should they be considered appropriate, the following should be taken into account under the reliability limb (as well as under the Market Benefits limb): • Improved reliability (valued by VCR and indexed annually and reviewed every 3 years in line with project thresholds) • Cost of network losses In addition, market benefits for: • New large distribution network assets, can be raised by project proponents for consideration by the DNSP in response to the RFP process; and • New small distribution network assets, can be raised by project proponents in response to the statement of network demand management opportunities contained in the DNSP's APR.
17. How should the range of benefits to be quantified under	While in principle ENERGEX supports the quantification of increased reliability above deterministic standards, it is

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the project assessment process be determined?	essential to ensure that the practical application of this requirement does not significantly increase the cost, complexity and timeframes for the delivery of reliability driven investment. ENERGEX also believes that in undertaking its Review and in developing the RIT-D, the AEMC should provide increased clarity on the process for option assessment and quantification. For example: • Whether the threshold values apply to included project or modelled plus included projects; • Whether the threshold values apply to nominal dollars or today's dollars; • Whether the threshold values include direct and indirect costs (capital plus operating); • The method for treating a combined network / non-network option; • The method for calculating refurbishment costs for a combined refurbishment / augmentation project; • Clarification on the parameters for sensitivity analysis; and • Clarification as to the intended operation and interaction of terms used throughout Chapter 5 of the NER and consistency in their application, e.g. 'total capitalised expenditure'; 'estimated capital expenditure'; 'estimated capital cost'; and 'capital cost of investment'.
18. How can the project assessment process ensure that environmental benefits are appropriately treated and quantified?	ENERGEX does not believe that recognition of environmental benefits (and costs) within the project assessment process can be addressed until such time as the policy framework for climate change is settled. For example, until there is clarity regarding the scope and coverage of the Carbon Pollution Reduction Scheme and the future application of exemptions for the distribution sector under the *Energy Efficiency Opportunities Act 2006*. As a general comment however, ENERGEX supports the inclusion of losses in the project assessment process, subject to clear guidance as to the manner in which losses are costed through the supply chain. Although the cost of losses is not currently captured in the decision-making process, ENERGEX does publish the expected project impact on losses through its consultation and project approval reports, including a carbon equivalent based on emission factors consistent with the National Greenhouse Accounts factors for transmission and distribution network operators.
19. How should a net benefit test be designed for	ENERGEX does not support an amalgamation of the reliability and market benefits limbs of the regulatory test under

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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 RIT-D. As noted by the AEMC, the market benefits limb of the regulatory test is applied by DNSPs as the exception rather than the rule. Unlike a TNSP, a DNSP has very little controllable impact on the market through a single network augmentation project and ENERGEX believes that a cost benefit decision approach (rather than a least cost approach) should only be applied in these rare circumstances. ENERGEX is also concerned that an attempt to amalgamate the limbs in a manner similar to that undertaken for the RIT-T would materially increase the regulatory burden on DNSPs by appearing to require an explicit assessment of market benefits (the range of which has yet to be prescribed) regardless of the driver for investment. Given that, even under an amalgamated test, the vast majority of investments would be expected to ultimately proceed under a 'least cost' approach (following the process of market benefit assessment), it is difficult to see how the amalgamation would optimise the decision making process and promote efficiency. Any perceived failings in the ability to capture market benefits should be addressed through the process of assessing which limb should be applied, not through the application of the limb itself.
20. Is there a need for a more specific decision making criterion compared to the existing regulatory test?	ENERGEX considers that the existing criterion for determining which prospective project goes through which process of assessment (i.e. reliability or market benefits) is adequate.
Chapter 5: Dispute Resolution Process	
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 DNSPs' annual planning processes?	The DRP only should apply to project assessments that have been the subject of consultation. The issue of a DNSP's compliance with the NER when preparing its APR is a matter for regulatory oversight, investigation and enforcement by the AER. It is not appropriately the subject of a DRP. This is consistent with existing jurisdictional planning arrangements.
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?	ENERGEX believes that the threshold for the DRP should be aligned to the threshold for public consultation. As noted earlier, the vast majority of augmentations under the RIT-D would be reliability based. This emphasises the importance of ensuring that the DRP does not unnecessarily delay investment. ENERGEX also notes the practical difficulties experienced by DNSPs and Registered Participants under the current process in seeking to determine whether there has been a shift in DUOS charges of greater than 2% when pricing is only determined on an annual basis. ENERGEX does not believe that this criterion should be carried across to the

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	revised DSP.
23. Who should be able to initiate the dispute resolution process?	ENERGEX believes that restricting the parties who are able to initiate a dispute to an appropriate sub-set is a combination of: • Defining the <u>parties</u> that may initiate a dispute. In particular, care should be taken when defining 'interested parties' to ensure that there is an appropriate nexus between the planning decision and the impact that is likely to result; and • Defining the <u>grounds</u> for initiating a dispute. ENERGEX believes that these must be clearly identified in the NER. For example, although a party may be 'affected' by a planning decision, a dispute should not relate to an individual's personal detriment or property rights.
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?	ENERGEX believes that: • A dispute should only be raised once a regulatory test process has been completed to avoid the planning process being frustrated by applications at each stage of the consultation process. Until the point of a final decision, issues regarding analysis or assessment should be addressed by potentially aggrieved parties through the RIT-D consultation process; • As noted above, the grounds for dispute must be clearly identified in the NER and should be restricted to the DNSP's compliance with the NER and RIT-D (refer to issue 27). Consistent with the DRP for transmission, a dispute should not relate to externalities under the regulatory test or an individual's personal detriment or property rights; and • Formal mediation is likely to be ineffective and lead to unnecessary delays in circumstances where the DRP is restricted to a review of the DNSP's compliance with the NER and RIT-D.
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?	ENERGEX considers that the AER is best placed to act as the arbiter under the DRP. The AER should be empowered to develop a Dispute Resolution Guideline, specific to the RIT-D, which supports the information requirements and procedural aspects of the DRP. As noted above, ENERGEX believes that mediation is likely to be ineffective and lead to unnecessary delays in

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	circumstances where the DRP is restricted to a review of the DNSP's compliance with the NER and RIT-D (a position which is supported by ENERGEX). If a mediation process was to be used, ENERGEX suggests that the mediator should be the Dispute Resolution Adviser under NER 8.2.2(a).
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?	Yes. This would support the principle of proportionality in design (i.e. that the costs of the process reflect its potential benefits) and would assist in mitigating the risk of unnecessary delays in investment. The arbiter should: • Have the ability to terminate the dispute proceeding on this basis at any time (i.e. not only at the commencement of proceedings). This would be consistent with NER 6A.30.5(d); and • Have the ability to disregard any matter raised by a party that is misconceived or lacking in substance when making its determination. This would be consistent with NER 5.6.6(m)(3).
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)?	The DRP should be restricted to a compliance review. In undertaking the compliance review, the arbiter should only have regard to information that was available to the distributor at the time that the project assessment was undertaken. Merits review or the inclusion of subsequently available information would inappropriately expand the scope of the DRP process and the powers of the arbiter to being regulatory, rather than review, in nature. ENERGEX agrees that the AER should have the ability to direct a DNSP to revise its analysis in circumstances where the DNSP has been found not to have complied with the NER and the RIT-D. Consistent with existing practice, DNSPs should not be directed as to what they can or cannot construct.
Chapter 6: Common Issues	
28. The appropriate balance of specification in the national	ENERGEX believes that Guidelines and 'Statements of Requirements' should not be quasi-regulatory in nature. For example, while a Guideline or Statement of Requirements would be appropriate to establish the standard format for

Question for Comment	ENERGEX Response
framework between the NER and supporting guidelines.	the provision of the APR, its content should be specified in the NER.
29. Should “urgent” investments be exempt from aspects of the national framework? If so, how should “urgent” be defined?	ENERGEX supports the inclusion in the NER of an exemption from the project assessment process for urgent and unforeseen investment. An attempt should not be made to include a definition of ‘urgent and unforeseen’ in the NER or RIT-D as this will necessarily be influenced by the specific drivers for the investment decision, including the prevailing policy and regulatory environment in the relevant jurisdiction.
30. What consequential amendments should be made to other arrangements to reflect the implementation of the national framework?	Clauses 6.5.6 and 6.5.7 of the NER already permit the AER to consider, when making a Distribution Determination, whether the proposed expenditure reasonably reflects “a realistic expectation of the demand forecast and cost inputs required to achieve the [operating or capital expenditure] objectives” and “the extent the DNSP has considered, and made provision for, efficient non-network alternatives”. Given this, ENERGEX does not believe that it is necessary to explicitly amend the list of factors to which the AER must have regard when assessing the DNSP’s proposed operational and capital expenditure, to include the outcome of the project assessment process.