25 February 2013

Mr Chris Pattas
General Manager - Network Operations and Development
Australian Energy Regulator
Level 35, The Tower
360 Elizabeth St
Melbourne Victoria 3000

Email: AERInquiry@aer.gov.au

Dear Mr Pattas

Issues Paper – Regulatory investment test for distribution (RIT-D) application guidelines

The Energy Networks Association (ENA) is pleased to have this opportunity to respond to the Australian Energy Regulator's (AER) Issues Paper on the Regulatory investment test for distribution (RIT-D) application guidelines.

Key messages:

- We acknowledge that the Issues Paper is the first stage of the consultation process on the RIT-D application guidelines. While we are appreciative of the opportunity to respond to the Issues Paper, more substantive comments will be able to be provided once the AER has developed the draft guidelines.
- It is important to recognise that there are several components of the RIT-T that do not apply to the RIT-D. As a result, the complexity of considerations under the RIT-D should be commensurate with the value and electricity market impact of distribution projects in order to ensure that the regulatory and administrative burden is proportionate.
- We would expect that the AER will provide guidance on *how* to consider market benefits, the magnitude of credible option analyses to undertake, and will impose sensible limitations on who should be considered an 'interested party' for the purposes of the guidelines.
- As a general rule, the guidelines should provide simple methodologies for the quantification of market benefits and deemed values where appropriate. However, the guidelines should also provide sufficient flexibility for a DNSP to use more complex methodologies where appropriate and justifiable.
- Service Target Performance Incentive Scheme (STPIS) payments and penalties are a transfer payment between participants in the market and should therefore not be included in any economic analysis under the RIT-D.
- ENA members are willing to assist the AER to create worked examples once the draft guidelines have been developed.

Responses to the specific questions from the Issues paper have been addressed in Attachment A to this letter.

The ENA is the peak national body for Australia's energy networks, which provide the vital link between gas and electricity producers and consumers. The ENA represents gas distribution and electricity network businesses on economic, technical and safety regulation and national energy policy issues.

Energy network businesses are valued at more than $60 billion, annually undertake investment of more than $6 billion in network maintenance and expansion, have annual revenue of over $20 billion and employ 40,000 staff.

The ENA appreciates the work put into these guidelines by the AER and appreciates the opportunity to continue to contribute to its development. If you have any questions please contact Jim Bain on 02 6272 1516.

Yours sincerely

Bill Nagle
Acting Chief Executive Officer

Attachment A

AER - Issues Paper - Regulatory investment test for distribution
ENA response to AER questions

Section 4. Similarities and differences between RIT-T and RIT-D

Question 1
Stakeholders should have regard to the regulatory test, RIT-T and RIT-T guidelines when considering their response to this Issues Paper. We are interested in what provisions of the RIT-T should be included in the RIT-D, modified or excluded altogether.

It is important to recognise that there are several components of the RIT-T that do not apply to the RIT-D. These include: the requirement to consider wholesale market competition benefits, changes in fuel consumption costs arising through different patterns of dispatch; the impact on generator bidding behaviour; and the requirement to undertake market dispatch modelling. These issues are not a component of the RIT-D as distribution projects generally do not influence these classes of market benefits. It is therefore not prudent for a DNSP to develop the critical competencies, systems and models to undertake this sort of analysis. As the RIT-T and RIT-D are different in these important ways, it is appropriate that they are treated separately.

To that end, we believe that the AER needs to be guided by the underlying principles in section 5.17.1 of the NER when developing the guidelines, in particular:

- each element of the test should be material to identifying the best credible option;
- the test must be capable of being applied predictably, transparently and consistently;
- the cost of the test must be proportionate to the impact of the options under consideration.

In summary, it is the ENA's position is that:

- The overall form of the RIT-T guideline, if used as a template for the RIT-D, is satisfactory with the exception that, within the RIT-D guidelines, a revised section 2.2 is required to clarify when the RIT-T is to be applied as opposed to the RIT-D.
- The definition of 'economic feasibility' on page 6 of the RIT-T guidelines is strongly supported as a clarifying statement for inclusion within the RIT-D guidelines. For avoidance of doubt, we recommend that AER also specify that economic feasibility and commercial feasibility have the same meaning for the purposes of the RIT-D.
- Elements of the RIT-T guidelines that discuss impacts on the wholesale electricity market are not relevant to the RIT-D and should therefore be removed.
- The operation and application of the RIT-D needs to be significantly simplified from the process outlined for the RIT-T, if the principle of proportionality of the analysis undertaken to the augmentation's value is to be met. This is particularly relevant given the large volume of RIT-D tests that will be required to be performed annually by DNSPs relative to the number of RIT-T tests performed by TNSPs. Specific elements of concern are discussed later in this response.
- Where a joint TNSP and DNSP project is determined to be a RIT-T project, the AER should provide guidance as to how it would deal with situations where there is no agreement between the DNSP and TNSP as to who should be the lead party.

- Section 4 of the RIT-T guidelines needs to be modified to reflect the differences in process between the RIT-T and RIT-D outlined in section 5.17.4 of the NER.
- The worked examples provided within the RIT-T guidelines need to be replaced with examples that are relevant to the type of distribution network augmentations likely to be subject to the RIT-D. The ENA is happy to provide examples of scenarios based on the market benefits limb of the existing Regulatory Test so that the AER can assess issues of scale and materiality.

Question 2

We are interested in how the differences in electricity distribution and transmission may require us to adjust our approach to the way RIT-T and RIT-D should be considered.

2.1 Lead Times

Generally lead times for customer initiated distribution projects where they are contributing to the costs but not paying the full costs are in the order of 12 to 18 months. Examples of such projects are embedded generation, expansion of shopping centres, government infrastructure, new underground residential developments (URD's) and the expansion of large agricultural facilities. Consequently the RIT-D process must be streamlined and capable of completion within a period of no more than several months if significant disruption to external party's construction program is to be avoided. It should be noted that the provision of electrical supply to a customer's installation is usually an early priority in the customer's construction schedule. As such, any delay in the provision of electrical infrastructure has a knock-on effect on the customer's overall construction schedule. Therefore, solutions which may be technically feasible should be capable of being ruled unfeasible by the DNSP should they not be achievable by the customer's required supply date.

2.2 Volume and value of tests

DNSPs do a vastly greater number of projects, of significantly lower capital cost than TNSPs. As a consequence, the number of RIT-D assessments required to be performed by DNSPs will be much higher than the number of RIT-T assessments performed by TNSPs, while the financial consequences of using a simplified test are much lower. Therefore, each RIT-D should be relatively simple to execute and concentrate solely on those elements that make a material difference to the determination of the final preferred option in order to prevent the cost of performing the RIT-D becoming overly onerous, in line with the intent of section 5.17.1 (c)(2) of the NER.

2.3 Impact on the Electricity Generation Market

There is likely to be no significant impact on the wholesale electricity market as a result of a distribution project evaluated under the RIT-D due to two elements:

- Any project in which transmission system upgrades are a credible option will be evaluated as a Joint Planning Project under the RIT-T. This effectively means that any project which makes major changes in power flows at transmission connection points and consequently in the transmission system will be excluded from consideration under the RIT-D.
- The typical size of embedded generation solutions to resolve distribution constraints not involving transmission connection points is typically in the order of a few MWs to a few tens of MW. Relative to the demand of the relevant NEM jurisdictional market, these individual generation solutions (i.e. tens of MWs) are likely to represent less than 0.5% of the peak demand of the respective NEM region, which is of the order of thousands of MWs. Therefore having no real impact on the generation market.

2.4 Scale of energy usage

The scale of energy usage in distribution networks is much smaller than in transmission networks; DNSPs at a distribution level deal in Megawatt hours rather than Gigawatt hours. Consequently, the impact on the outcome of the test of those elements of the network that are concerned with energy (i.e. losses, reliability etc) is much smaller than is the case with a typical transmission augmentation. Some elements, for instance, the evaluation of the reliability impacts due to VCR under N-2, are rarely material at a DNSP level while others such as N-1 reliability calculations at a multi transformer substation have similarly low impact on the outcome of the evaluation due to the relatively low likelihood of the event occurring.

When combined with the issue of lead times discussed earlier, this implies DNSPs need the flexibility to ignore entire classes of market benefits (due to their relative immateriality) at the start of the process rather than need to prove this for each individual assessment conducted, provided the reasons for these benefits not being relevant is explained in the relevant RIT-D document published by the DNSP..

2.5 Number of Augmentations per test

In heavily loaded distribution networks, there are typically a series of augmentations required at different stages of the evaluation period to resolve new or re-emerging constraints in an area rather than a single augmentation as is given in the RIT-T examples. These augmentations may be traditional network augmentations, non-network solutions or a combination of both (e.g. network augmentations to facilitate implementation of the non-network solution or where the non-network solution only acts as a deferral solution after which, network solutions are subsequently required). In addition, each augmentation impacts upon other regional constraints so that the breadth of consideration can also be much wider. This suggests that the RIT-D evaluation of each set of augmentations needs to be much simpler than the RIT-T. We therefore request that the RIT-D guidelines provide real world scenarios and examples to provide greater clarity in how the test should be applied. A list of such examples is provided later in response to Question 18.

2.6 Market Benefits

The ENA notes that there are some major differences between the RIT-T and RIT-D in the assessment of market benefits. The RIT-T requires an assessment of a base case (no credible option implemented) and the quantification of additional market benefits associated with large generator competition benefits, fuel costs and inter-regional benefits. The market benefits required to be quantified under a RIT-T are likely to be much more significant than those that have to be considered and optionally quantified under the RIT-D. For example, the approach to considering the market benefits of customer load curtailment, involuntary load curtailment and distribution network losses for the RIT-D would be significantly different because typically a RIT-D project would affect a smaller proportion of the National Electricity Market (NEM) and unlikely to have any impact on inter-regional benefits.

<u>Section 4.1 Removal of the base case</u>

Question 3
We are interested in how stakeholders believe this will change the analysis for RIT-D proponents.

Since the RIT-D is a process for the ranking of potential credible options in order to identify the option with the highest economic benefit, removal of the base case (the case where no credible option is implemented) makes for a more efficient and cost effective RIT-D assessment process as it does not alter the RIT-D ranking of possible credible options relative to each other. We are therefore, in principle, supportive of this proposal as the requirement for a base case option has proven to be problematic at times due to:

- The difficulty in generating a valid base case due to voltage collapse in many modelled distribution networks, especially in weak rural distribution systems, over a period of analysis in excess of 10 years.
- The implausibly large reliability benefits gained under any augmentation option when the base case would result in load shedding under normal “N” conditions in order for loads to remain within equipment ratings. Obviously, as the load at risk increases, so do the number of hours per annum that this shedding is required to occur. In one recent market benefits test, the VCR values associated with the shedding of load were well in excess of the total economic output of the area being modelled.

- The information gained from the base case is netted off between options and is therefore never used.

However, problems may arise in situations where the preferred option has a negative value – i.e. is at an overall cost to the market and the local jurisdiction requires a positive outcome in comparison to a doing nothing scenario; e.g. in Victoria or in areas of doubt as to what falls under the heading of 'reliability corrective action'.

We suggest that this should be resolved by:

- Providing DNSPs with the option of either preparing a 'Do Nothing' option as a default base case or directly comparing options without the need for a base case in situations where the DNSP feels it is appropriate;
- Clarifying the definition of 'reliability corrective action' where a non-prescriptive reliability standard (i.e. N-1, N-2) is in force with regard to equipment overloads and Health and Safety considerations (e.g. line clearance) are at play.

<u>Section 4.2 Distribution level market benefits</u>

Question 4 We are seeking stakeholder views on how any of the factors which should deliver market benefits listed above should be clarified.

The AER should provide advice on how to *consider* market benefits. For example, it might be prudent to specify in the guidelines that a market benefit is considered immaterial (and therefore no RIT-D quantification is required) if a 'back of envelope' calculation determines that it is less than a certain percentage of project cost or based on a lower burden of proof where in a class of projects particular benefits have proved immaterial in previous RIT-D assessments. We would also submit that it is equally important that the guidelines provide examples of items not be included, for example unpriced externalities.

In terms of how any of the factors which should deliver market benefits listed above should be clarified, we offer the following comments:

4.1 Voluntary Load Curtailment

It is the ENA's view that three forms of this type of load curtailment exists:

1. where load is curtailed at peak times by a customer due to the wholesale price;
2. where load is curtailed due to a payment received from a market participant (e.g. DNSP); and
3. where economic expansion (by potential or existing customers) is curtailed through the project not proceeding due to the cost of augmentation associated with connecting to the distribution network.

The first reason for voluntary curtailment is highly unlikely to be relevant to the RIT-D as this is only impacted by changes in the wholesale price and as previously noted, individual distribution augmentations are typically not of the scale to alter this. (Augmentations of the scale required would generally involve connection point or transmission lines as options and therefore be evaluated under the RIT-T)

The second form of voluntary curtailment is a valid method of resolving identified network constraints, however it is difficult to quantify the value respective customers will place on their load curtailment or their willingness to participate in such a scheme. Such curtailment may be as a result of either a shutdown (i.e. loss of production) or a time shift in production which results in no loss of overall production. The question of materiality and appropriate compensation levels to be applied within the test is important to clarify in this instance as this will significantly impact the viability of this option.

The third form of load curtailment is also a reality particularly in remote areas of the network or areas which are either already constrained or a constraint is imminent (for instance on Kangaroo Island in South Australia and in far western Queensland). This form of curtailment is an economic form of curtailment whereby customers or potential customers curtail local development (i.e. do not proceed) due to the prohibitive nature of the augmentation costs required to enable their proposals to proceed. This is particularly relevant for large mining loads in rural areas. Guidance is required on whether or not the societal or economic impacts to the local region, State or national economy should be included and if so, how this should be quantified and evaluated.

4.2 Involuntary load shedding

We note the historical differences in methods ('willingness to pay', 'consumer costs incurred' etc.) used across jurisdictions in calculations of the $ per MWh value used to evaluate the impact of involuntary load shedding. We also note the significant work currently being undertaken in this area by the AEMC under their Review of Distribution Reliability Standards and Outcomes.

Consequently, given the requirement in section 5.17.1(c)(3) for consistency and transparency, we believe that it would be appropriate for the AER to clarify their views, on an annual basis, on the value of customer reliability (VCR) and the appropriate margins (for sensitivity analysis purposes) to be used within each NEM region in application of the RIT-D. The derivation of these values could then be addressed later through the customer reliability work stream.

It is also important to make clear that VCR calculations are only required to be performed or considered where their use may potentially impact the result of the test. For example, the impact of minor changes in the reliability of low power systems does not need to be calculated.

4.3 Other Parties Costs

Clarification is required as to what costs should be included or excluded under this heading within the context of a DNSPs system, remembering that constraints solved by potential transmission upgrades and therefore potentially impacting the wholesale market are excluded from evaluation under the RIT-D. This would appear to be related to the third case in our comments relating to Voluntary Load Curtailment above. For instance if an augmentation relaxes network constraints to the extent that the cost of connection or augmentation of an existing connection to the network for a third party changes, then should that benefit be quantified and if so how?

Another example requiring clarification, is where an unrelated network change alters the costs to a specific embedded generator of connecting to or operating in the network (either positively or negatively). We suggest that if this clause is intended to include the costs of existing or future parties with embedded generation connected or proposing to connect to the network, then these should be included only to the extent that the generation contractually resolves or creates network constraints.

This effect can happen at all scales of generation, for instance, where a SWER system is converted to three phase then the connection of larger levels of solar PV is technically feasible, Similarly, the connection of new generation to resolve network constraints may either positively or adversely affect an existing embedded generator through alteration of their Distribution Loss Factor (DLF).. See item 5 below related to transfer capacity for relaxing of constraints on existing generation.

4.4 Timing of Expenditure

The timing of expenditure is of major concern. For instance, if expenditure occurs in the last year of the period of analysis in one option and not at all in another, this may significantly skew the overall result of the analysis towards the option with the earlier expenditure. Of the many options available to minimise this effect, it is suggested that the residual network values at the end of the analysis period be added back into the analysis. We seek confirmation from the AER of their preferred method of avoiding this issue.

4.5 Load Transfer Capacity and capacity of Embedded Generators

We request guidance on how load transfer capacity should be explicitly included in the analysis in a cost effective way other than by doing the test over an unreasonable number of years and therefore including changes in this capacity through changes in the timing of network augmentations. Moreover, the description of load transfer on page 12 which defines it as '...identifies the potential to shift the timing of usage away from peak periods, or to shift usage away from highly utilised assets to lower utilisation assets' is not consistent with the definition in the Rules.

It should also be noted, for reasons of efficiency of operation, DNSPs generally support a very limited range of conductor, transformer and substation sizes. Significant effort has been applied to the generation of standardised designs and rationalisation of equipment in order to achieve operational savings. This rationalisation leads (as a consequence) to a limited palette of available upgrade options available to the DNSP.

In terms of the capacity of embedded generators, our major concern is how to calculate the value of the constraint that a distribution network may impose on an embedded generator. There are three issues;

1) calculation of the capacity (installed or potential),
2) calculation of value of the electricity generated (for instance between a wind farm and a peak lopping diesel generator) and
3) calculation of the quantum of energy produced (i.e. historical values may be constrained, future values fall short of the transparency and consistency test).

4.6 Any other class of market benefits

In relation to 'any other class of market benefit determined to be relevant by us', we are uncertain as to how this process would work in practice, particularly within the time constraints of the RIT-D process. We note that the RIT-T provides the opportunity for proponents to identify other relevant market benefits and costs and to seek written confirmation from the AER that they are accepted. We would expect the RIT-D would operate in a similar manner.

Question 5
We are also interested in whether we should look at any additional distribution level market benefits, other than those specified under clause 5.17.1(c)(4). In particular, we are interested in whether broader types of demand side participation are likely to result in distribution level market benefits. In addressing this, we recommend that stakeholders have regard to the AEMC's Power of Choice Review.

5.1 Additional Market Benefits

Other benefits that might be considered include:

- Changes in level of avoided TUOS payments due to embedded generation not using the transmission system. Such consideration should only be made where the embedded generator operates at times which reduce the peak demand and therefore impact the TUOS charge levied by the TNSP on the DNSP. These are effectively a transfer between market participants as the costs of the transmission system do not change and therefore should be excluded from consideration under the RIT-D. Note that if the embedded generation resulted in changes in the timing of transmission system upgrades then this would cause the project to be considered under a RIT-T and the benefit of this would be considered under the change in timing elements of that test.
- Payments to demand side aggregators for a reduction in demand. As the bulk of these payments are compensation to the aggregators for the real costs of arranging the demand side response our view is that they should be included in the RIT-D. In short, aggregators are in effect service providers who arrange and manage load curtailment activities of customers. Their cost offering should be able to be considered against a network solution just as a third part offer to generate would be.

5.2 Demand Side Participation

We note that the RIT-D process makes explicit and transparent the existing obligations to "consider" DSP when evaluating investment options. Additionally, the new requirement for a demand side engagement strategy will assist in increasing the profile of DSP options. The RIT-D would therefore operate in a similar manner to the current regulatory investment test, but would allow distributors to include market benefits in the analysis of business cases for demand management.

The RIT-D is not without issue. This is because simply being able to consider the benefits does not enable proponents to access additional funds to cover costs of such projects within the regulatory period. The costs of the demand management project still must be paid for through the difference between the value of deferred network capital (return on and return of capital) included in the revenue allowance during the period, and the additional operating costs required (in addition to the allowance) to facilitate and operate the project. The business case for a network proposing a demand management option is therefore effectively the same under the RIT-D as it is under the current investment test – savings within the framework must be sufficient to pay for the project, otherwise it cannot proceed. At no point can a network access a separate funding stream to help pay for the project even though the benefits that may arise from the project may be spread through the market and more than outweigh the costs.

The inability of DNSPs to access a share of market benefits in financial terms means that investment in demand management projects will occur in fewer circumstances than might otherwise be the case (i.e. viable cases will not be pursued).

We would contend therefore that the inclusion of market benefits in the analysis of the business case does little to actually facilitate (i.e. fund) project implementation, unless market benefits are identified and incorporated in the determination of the allowed revenue for a regulatory period or as an addition to allowed revenues. There is an opportunity to change this within the current regulatory framework through the AER's incentive arrangements and the RIT-D guidelines.

Question 6

Specifically, noting the recently released Power of Choice report, does the RIT-D consideration of market benefits need to be amended to support demand side participation?

As projects are reviewed under the RIT-D, opportunities will emerge for DSP as the most efficient solution from a whole value chain viewpoint. To ensure efficient DSP is delivered in-line with the NEL objectives, the guidelines could specify the values or methodologies for evaluating the full chain market value of demand reductions. This would allow networks a share of the transmission and generation benefits that a network DSP option delivers. The DSP market benefits would be predetermined deemed values for generation and transmission set to equal the long run marginal cost of augmentation.

More generally, It is the ENA's view that the RIT-D should not favour any one technology, ownership structure or method of augmentation; (i.e. the focus of the RIT-D should be an objective test to identify a preferred option which resolves the identified constraint in a manner of the greatest net benefit to the users of the network, rather than one to promote the preferences of any particular group of stakeholders). It is important to note the difference in this case between elements that impact the market as a whole, either by increasing costs or reducing benefits and those elements that represent transfers between market participants that change the profitability of differing sectors.

Question 7

The RIT-D process is designed to capture significant new projects and programs. It is feasible that the scale of these new projects and programs could be large enough to have a material impact on overall network reliability. In these cases, it is most likely that the reliability impact will be a positive one and this would then result in the DNSP receiving an incentive payment under the Service Target Performance

Incentive Scheme (STPIS). It is also technically feasible that the STPIS outcomes could be negatively impacted by a RIT-D project or program. In both of these cases, it would be reasonable to assess the STPIS impact and potentially adjust the STPIS targets to account for the forecast reliability change. How should the consideration of market benefits under the RIT-D recognise the impact the proposed works would have on the STPIS?

DNSPs plan their network to more or less maintain system reliability to the same level over the long term. Without augmentation of the network in some form, this reliability is slowly degraded over time as the number of connections per asset and consequently, loading per asset increases in line with the natural increase in the number of connections and the level of peak demand. Simply focusing on the projects which counteract this degradation without adjusting for the degradation itself will distort the design of the STPIS scheme and its outcomes. It is therefore difficult to determine the impact on STPIS due to the resolution of a single constrain on an overall region.

As such, we do not support any proposal to consider revision of the overall STPIS targets for a DNSP as part of the RIT-D process and associated guidelines. Given the intent of the NER is not to make the level of analysis undertaken by DNSPs unduly onerous, requiring DNSPs to consider the impact of a single project on the STPIS targets would be disproportionately burdensome with respect to the value of the augmentation.

In addition, it is our view that STPIS payments represent an economic transfer between parties in the market and changes in these payments are and should therefore be excluded from consideration under the RIT-D assessment as the benefit gained by one party (increase in payments) is offset by the cost to the other party (increase in charges). This is similar to the exclusion of local compensation payments made to consumers based on length and frequency of outages that originate from license conditions.

Question 8
A portion of electricity is naturally lost in its transmission and distribution. RIT-D proponents pass through these costs on the network, although proponents are obligated to comply with certain efficiency standards. How should the economic cost of electricity loss be treated within the market benefits assessment?

We believe that losses should be valued at the long run average cost of generation in the relevant NEM region in which the DNSP operates, rather than the long run marginal cost of generation. Calculations show that the majority of the economic loss occurs at non peak time when there is ample spare capacity. The long run average cost, rather than the market price should be used as the latter includes the transfer of profit between market participants, consideration of which is excluded under the regulations.

As was the case with the Value of Customer Reliability (VCR), it would be of significant benefit in terms of clarity and the avoidance of challenging by third parties on values applied within the RIT-D, if the AER published these values (and the variances for the purposes of the sensitivity analysis) on an annual basis for each NEM region.

In our experience the value of losses is a secondary element when comparing augmentation options due to:

- The average long run cost of generation being relatively small compared to the Value of Customer Reliability (e.g. ~ $35 MWh cf $50,000 MWh).
- The benefits attributable to a reduction in losses in a typical distribution system under consideration being quite small especially when compared between two upgrades both of which result in decreased losses.

Having said this, we believe that it is important for public policy to include the impact of losses within the RIT-D even though they are rarely material to the outcome, in order for policy makers to better understand the functioning of the electricity system (i.e. the calculations are of an educational rather than practical benefit).

Our preference is for the AER to not specify a method by which the MWh value of losses is calculated as the preferred method will depend significantly on the information available to the DNSP. For instance, the method used will differ significantly depending on the availability of reliable SCADA values for the system under consideration.

The question of feeder losses emanating from a zone substation is difficult to resolve as these may be substantial but may be unquantifiable with any degree of accuracy at a reasonable cost. Consequently, the ENA suggests that consideration of changes in losses as a result of augmentations in these instances are at the discretion of the relevant DNSP based on clause 5.17 (c) 3 on the grounds of consistency and transparency of process.

Section 4.3 Material and adverse NEM impacts for the purpose of interested parties

Question 9
We are seeking stakeholder views on who should be considered an interested party under this definition.

In principle, the ENA supports the AER's change in terminology on the presumption that the intention is to prevent disputes or objections on the RIT-D outcome being raised with the AER by third parties for reasons which would be better resolved by relevant town planning authorities. Given the intent of the RIT-D is to determine the solution which derives the greatest market benefit, rather than consideration of local planning authority criteria, we are supportive of this premise.

The ENA however would question the legal robustness of the proposed change in achieving the desired outcome and would therefore request the AER to obtain legal guidance and subsequently advise the ENA on the ability of this change in wording to deliver the desired outcome.

It should be noted, that, during the AEMC consultation process associated with the rule change which resulted in implementation of the RIT-D, the ENA consistently argued that disputes relating to the outcome of the RIT-D, should only be capable of being raised by parties which had responded during one of the various consultation periods throughout the process. The intent of this request to the AEMC, was to mitigate those objections to or concerns with augmentation proposals (whether network or non-network) which were better resolved by local planning authorities than the AER on either technical or financial merit.

We also note that in its submission to the consultation paper on the draft Rules, the AER expressed concern that the draft definition of 'interested party' was ambiguous. The AEMC amended the Rules to recognise that without further clarification, the definition of 'interested party' may unintentionally expand the scope of parties eligible to raise a dispute beyond national electricity market impacts. The final Rules therefore clarified that the material and adverse market impact experienced by the interested party must arise in the national electricity market (NEM).

The AER also has the discretion to determine what it considers to be a material and adverse NEM impact for the purposes of interested parties. We would therefore recommend that the AER give careful consideration to this matter to avoid the potential for vexatious disputes. As an example, it would be inappropriate for a party to be deemed an 'interested party' if their interest in the project related to the potential future use of a new investment rather than the investment itself. This could arise if a party is concerned that the NEM investment may be a forbearer to the development of a new mine or industrial complex.

Question 10

We are interested in what guidance stakeholders would find useful in interpreting the definition of interested parties.

Please refer to response to question 9.

Question 11
We are of the view that the change in terminology from material and adverse 'market impacts' to 'NEM impacts' improves clarity. We are seeking stakeholders' views on this.

Please refer to response to question 9.

Section 5.1 Estimating costs

Question 12
We are interested in stakeholder views regarding what other financial costs are likely to be relevant.

The ENA would encourage the AER to adopt a flexible approach to the consideration of costs to incorporate risk and managing uncertainty.

In addition, could the AER confirm that where a third party has offered a price for Network Support in response to a RIT-D consultation such as the Non Network Options Report, that that price is deemed to reflect the true economic cost of the service of the party and therefore the DNSP does not have to further investigate the third party proposal to distinguish between elements of market costs and market transfers between parties.

Question 13
The RIT-T specifies that transmission network service providers could determine additional classes of costs if we agreed that they were relevant. We are seeking stakeholders' views on whether it should make a similar specification for RIT-D proponents under the RIT-D.

Provisions available to RIT-T proponents for the quantification of any other relevant classes of costs not identified in the Rules, or in the RIT-T, should also be available for RIT-D projects. RIT-D proponents, rather than just the AER, should be able to determine additional relevant classes of costs and to obtain agreement in writing from the AER during the RIT-D project assessment stage in a process similar to the RIT-T.

Given the real time restrictions on many RIT-D evaluations, particularly those that involve customer connections, the AER needs to state the time frame within which they will provide a decision on the relevancy of the costs proposed and also on whether or not they will as a matter of policy make such agreements public. We would support making these agreements public as this would increase the knowledge base of all DNSPs and therefore the efficiency of the market.

Question 14
The RIT-T specifies that if the costs were materially uncertain, the cost should reflect the probability weighted present value of the direct costs of the credible option under a range of different cost assumptions. We are seeking stakeholders' views on whether we should make a similar specification under the RIT-D.

This should be limited to situations where there is material uncertainty about input costs and where the choice of preferred option is shown to be sensitive to those variations. For the purposes of sensitivity analysis, it would be beneficial, if the AER were to include within the Guidelines, guidance regarding the variances which should be applied to the augmentation costs (i.e. ± 10%, ± 20%).

Section 5.2 Determining discount rates

Question 15 We seek stakeholder views on whether the RIT-D should specify the same methodology for determining the discount rate as the RIT-T and current regulatory test.

It would be a useful simplification to specify the use of the current regulatory WACC (i.e. the WACC in the prevailing Distribution Determination) as the discount rate. If the AER chooses to specify a different process, then the guidelines should set out the reasoning behind such a choice and provide a clear and simple means of determining the appropriate rate, including worked examples. In addition, specification of suitable variances of the discount rate (e.g. ± 1.5%, ± 3%) for use within the sensitivity analysis would also be of assistance in order to maintain consistency across DNSPs and reduce the likelihood of third party challenges to the RIT-D results.

Section 5.4 Methodologies for estimating costs

Question 16 We seek stakeholder views on the methodology that the RIT-D should specify for estimating costs.

It is suggested that any methodology should not be overly prescriptive, but that it should specify that cost estimates should be risk based estimates that take into account the level of uncertainty associated with the particular investment.

It is also suggested that DNSPs should be able to use those “building block” costs used in preparing their Regulatory Reset submissions. Given as part of the Reset determination, these building block costs are reviewed and ultimately approved by the AER, they should be considered suitable for use when undertaking the RIT-D analysis in order to prevent DNSPs sinking potentially large amounts of money and labour into specific project estimates. Once again, this relates to a suitable level of proportionality between the RIT-D analysis and the cost of the augmentation being considered.

Question 17 We are interested in whether stakeholders think the methodology should be adopted from those specified under the RIT-T and regulatory test.

The methodology could be adopted from those specified under the RIT-T and the regulatory test but the methodology should recognise that the scale and nature of some distribution investments may not require the same level of analysis and accuracy as that for a major transmission investment.

More generally, we seek guidance and clarification on the extent of possible credible option analysis required for each RIT-D project. The AER RIT-T Guidelines state that a credible option may not be economically feasible if it has an estimated cost that is substantially larger in magnitude than that of other options to address the *identified need*, and is not expected to have significantly higher market benefits.

It is our position that the costing methodology proposed in the RIT-T is inappropriate for use within the RIT-D and that significant changes are required. The RIT-T requirement to explicitly adjust costs for externalities such as exchange rate, price of steel, price of labour or land etc. for an augmentation, on an element by element basis is extremely onerous and disproportionate to the likely augmentation cost.

We recommend that the evaluation of the impact of different cost assumptions should be better performed through sensitivity analysis rather than some highly complicated and arbitrary weighting system. This would allow a simple impact assessment where the cost of construction of each DNSP augmentation is varied uniformly by a set percentage to judge the sensitivity of the evaluation to such changes (high cost, expected cost and low cost states of the world). Guidance on an acceptable variance for sensitivity analysis purposes would be welcomed.

Section 6 RIT-D Guideline Issues

Question 18 We seek stakeholder views on what guidance and examples for distribution would be useful to in the RIT-D guidelines.

We recommend that a number of distribution network specific examples including the consideration and quantification of market benefits listed in clause 5.17.1 (c)(4) be developed, and that they are sufficiently broad to recognise the fact the network management is increasingly an integrated approach rather than being conducted exclusively on a project by project basis. Specifically, guidance is required on the process and justification required when determining the case that market benefits would not be material in the evaluation and therefore not required to be quantified for the RIT-D evaluation.

The ENA requests that the AER consider the following cases and provide guidance and worked examples for:

- New distribution feeder;
- New sub-transmission feeder/line, including a replacement and augmentation component for both radial and meshed sub-transmission lines;
- Additional transformer at a Zone Substation;
- New Zone Substation (augmentation);
- New Dual Function Asset;
- Incidental augmentation associated with an asset replacement project; and
- Augmentation of a Zone Substation due to a customer initiated project (i.e. customer connection).

Members would be happy to co-operate with the AER in developing worked examples once the body of the guidelines have been developed.

Section 6.1 Operation and application of the RIT-D

Question 19 The RIT-T guidelines provide guidance and worked examples on these topics. Having regard to the RIT-T guidelines, we are interested in whether the RIT-T guidelines provide useful information which should be adopted in the RIT-D guidelines.

The RIT-T guidelines provide many useful worked examples that are applicable to the analysis of potential credible options on the transmission network and cover the complexities involving the evaluation of broader electricity market benefits such as competition benefits, generator fuel cost, benefits to other regions etc. Many of the worked examples do not apply to the evaluation of projects on the distribution network.

The RIT-D contains fewer classes of market benefits and does not concern itself with the broader RIT-T specified market benefits and the analysis of “states of the world” that include the wholesale market. Our members would find it more beneficial to be given guidance on a range of worked examples focusing on the assessment of common types of RIT-D projects, and the consideration and decision of whether to quantify the relevant RIT-D specified market benefits.

Question 20

Additionally, we are interested in whether stakeholders consider the guidelines should provide guidance and worked examples on any additional areas that have not been specified under clauses 5.17.2(c) or 5.17.2(b)(2) of the NER.

At a minimum, we consider that guidance and worked examples for the RIT-D process and the valuation of market benefits and option costs under of clauses 5.17.1(b)(2) and 5.17.2(c) should be included.

<u>Section 6.2 Application of guidelines</u>

Question 21
We seek views on what guidance we should give on when a regulatory test assessment will be considered to have commenced for the purposes of 11.50.5(c).

DNSPs should be free to elect which RIT applies to all investments that have commenced, but not yet finalised at the time of commencement of the RIT-D.

A regulatory test assessment should be considered as commenced where a clear network need has been identified, documented and consideration of options has been undertaken.

<u>Section 6.3 Process to be followed</u>

Question 22
We seek stakeholders' views on whether there are any particular areas where further guidance on the RIT-T assessment process would be useful.

As indicated in our response to question 1, where a joint TNSP and DNSP project is determined to be a RIT-T project, the AER should provide guidance as to how it would deal with situations where there is no agreement between the DNSP and TNSP as to who should be the lead party.

It would be useful for the AER to provide a sample flowchart illustrating how projects flow through the process. This would simplify explanations to the general public, interested third parties and senior management of how the process operates.

Clause 5.17.4 (1) requires the DNSP to consult with all registered participants, AEMO, interested parties and non-network providers. Clarification is requested on how the DNSP is to identify and maintain the contact details of these various parties for consultation; the assumption being that not all registered participants, interested parties or non-network providers will have registered their interest through the DNSP’s Demand Side Engagement Register.

The concern is that the list of Registered Participants available on the AEMO website contains no such contact details as well as including many parties who will have no interest in the activity of the relevant DNSP (i.e. other DNSPs or unaffected TNSPs). Our preferred solution is for the DNSP to notify the following groups:

1. The AER;
2. AEMO; and
3. Those parties registered on the DNSP’s Demand Side Engagement Register.

We therefore request that the RIT-D Guidelines provide further guidance on this matter.

<u>Section 6.4 Estimating market benefits</u>

Question 23

We seek stakeholder views on what methodologies the RIT-D application guidelines should adopt for valuing market benefits.

Given the more numerous and lower value of distribution projects, there is a need for simplified methods of quantification. Deemed values where possible should be established (which may vary by DNSP and be subsequently updated in determinations). Simplified methods should be developed where case by case evaluation is required. DNSPs should be free to apply more complex methods where they deem it appropriate, subject to demonstrating their validity.

The question of materiality of the benefits considered (or not considered) is likely to be the major area for dispute. We therefore seek clarification of at which point a benefit can be considered to be immaterial to an outcome and therefore excluded from being considered.

<u>Section 6.5 Dispute Resolution</u>

Question 24
We seek stakeholder views on what dispute resolution guidance would be of assistance. The RIT-T guidelines provide guidance on dispute resolution. Having regard to the RIT-T guidelines, we are interested in whether this content should be adopted into the RIT-D guidelines.

Members agree that the dispute resolution process described in the RIT-T guidelines could generally be adopted into the RIT-D process. However, we note that clauses 5.16.5 (g) (2) & (3) are not applicable to the RIT-D.