26 February 2013

Mr Chris Pattas
General Manager - Network Operations and Development
Australian Energy Regulatory
Level 35, The Tower
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Email: AERInquiry@aer.gov.au

Dear Chris

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

SA Power Networks 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.

Please find attached our submission which responds to each of the questions raised within the AER's issues paper

If you have any queries on our submission please contact Mr Grant Cox on 08 8404 5012 or e-mail grant.cox@sapowernetworks.com.au.

Yours sincerely

Sean Kelly

Sean Kelly
General Manager Corporate Services

Preamble

The following is a submission by SA Power Networks to the AER's Issues Paper entitled "Regulatory investment test for distribution" dated January 2013. We welcome the opportunity to respond to this Issues Paper and consider that our response will be of assistance, particularly as SA Power Networks has had many years experience in applying similar tests to significant network projects.

The responses are set out according to the section headings within the Issues Paper.

Should the AER require any clarification of the views raised in this document, please contact the following people,

- SA Power Networks: Grant Cox, Manager Regulatory Affairs, grant.cox@sapowernetworks.com.au or

We would expect as part of the AER's consultative procedures we will be afforded the opportunity to comment on any draft guideline s prior to finalisation.

Responses 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:

1. the requirement to consider wholesale market competition benefits;
2. changes in fuel consumption costs arising through different patterns of dispatch;
3. the impact on generator bidding behaviour; and
4. the requirement to undertake market dispatch modelling.

These issues are not relevant to the RIT-D since distribution projects generally do not influence these classes of market benefits. It is not prudent therefore, for a DNSP to develop the critical competencies, systems and models required to enable it to undertake this sort of analysis. As the RIT-T and RIT-D are fundamentally different in these ways, it is appropriate that they are treated separately.

To this 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:

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

In summary, it is our position that:

1. The overall form of the RIT-T guidelines, if used as a template for the RIT-D, is satisfactory with the exception that, within the RIT-D guidelines, a revision to section 2.2 is required to

clarify when the RIT-T is to be applied as opposed to the RIT-D (i.e. for "Joint Planning Projects").

2. The definition of "economic feasibility" found on page 6 of the RIT-T guidelines is strongly supported for inclusion within the RIT-D guidelines. For the avoidance of doubt, we recommend that the AER also clarify whether the terms economic feasibility and commercial feasibility should be taken to have the same meaning for the purposes of the RIT-D.
3. The definition of "identified need" within section 3.1 of the RIT-T guidelines should take into account the differences in regulations governing transmission and distribution networks. In particular, the definition needs to clarify whether or not there is a requirement to operate the distribution network within the appropriate equipment ratings (i.e. in a satisfactory state or purely based on maintaining existing levels of supply reliability).
4. Those elements of the RIT-T guidelines which discuss impacts on the wholesale electricity market are not relevant to the RIT-D and should therefore be removed.
5. 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 addressed later within this response.
6. Where a joint TNSP and DNSP project is determined to be a RIT-T project, the NER requires a lead party to undertake the RIT-T with this lead party being agreed by the DNSP and TNSP. Where agreement can not be reached, the RIT-D guidelines (and subsequent amendments to the RIT-T guidelines) should either provide a resolution procedure under which the AER will determine the lead party or provide guidance or scenarios on whom the lead party should be. It would be our preference, if all RIT-T assessments were performed by the TNSP in order to avoid DNSPs from having to develop systems and procedures to enable them to perform both tests.
7. Section 4 of the RIT-T guidelines needs to be modified to reflect the differences in process between the RIT-T and RIT-D as outlined in section 5.17.4 of the NER.
8. The worked examples provided within the RIT-T guidelines need to be replaced with examples that are relevant to the type of network augmentations likely to be performed by DNSPs which will be subject to the RIT-D.

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 (ie where the customer is contributing to, 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.

The guidelines should also clarify when a customer connection project may require a RIT-D. The provision of electrical supply to a customer's installation is usually an early priority in the customer's construction schedule, and undertaking a RIT-D may adversely affect the customer's overall construction project in terms of timing.

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 for DNSP augmentations are much lower than those generally associated with TNSP projects. 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:

1. 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.
2. 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 an insignificant proportion of the peak demand of the respective NEM region, which is in the order of thousands of MWs, thus 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 distribution level for the purposes of the test, deal in Megawatt hours rather than Gigawatt hours. Consequently, the impact on the outcome of the test of those elements of the test concerned with energy (ie losses, reliability etc) is much smaller than is the case with a typical transmission augmentation.

When combined with the issue of lead times discussed earlier, this suggests 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 (eg Screening Test Notice) 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 (eg 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

We note that there are some major differences between the RIT-T and RIT-D in the assessment of market benefits. The RIT-T requires assessment of a base case (ie 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 lower than in a RIT-T project as typically, a RIT-D project affects a smaller proportion of the National Electricity Market (NEM) and is therefore unlikely to have any impact on inter-regional benefits.

Section 4.1 Removal of the base case

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

Since the intent of the RIT-D is a process for ranking potential credible options to identify the option with the highest economic / market benefit, removal of the base case (i.e. a "Do Nothing" scenario) potentially makes for a more efficient and cost effective RIT-D assessment process. This is because a "do nothing" scenario is not a credible option where the identified need is reliability corrective action. Thus, its removal does not alter the RIT-D ranking of possible credible options relative to each other.

Accordingly, Power Networks supports in principle this proposal to remove the need to consider a base case. In the experience of SA Power Networks the requirement for a base case option has proven to be problematic due to the difficulty in generating a valid base case model caused by voltage collapse in many modelled distribution networks, especially in weak rural distribution systems., over a period of analysis in excess of 10 years .

Whilst SA Power Networks agrees to the removal of the requirement to include the base case, we consider that it should be allowed to be included. Problems may arise in situations where the preferred option has a negative value (i.e. at an overall cost to the market) and the local jurisdiction requires a positive outcome in comparison to a "do nothing" scenario; e.g. in Victoria or where doubt exists 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 comparing benefits against a "Do Nothing" option or directly comparing options, 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 or where Health and Safety considerations (e.g. line clearance) are at play.

Section 4.2 Distribution level market benefits

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 within the guidelines that a market benefit is considered immaterial (and therefore consideration within the RIT-D is not required) if an initial calculation determines that it is less than a threshold percentage of the total project cost or where 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 to 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 our 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) for network support; 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. As previously noted, individual distribution augmentations are typically not of the scale to affect this. Augmentations of the scale required to do so would generally involve transmission connection point or transmission lines as options and therefore be evaluated under the RIT-T as a Joint Planning project.

The second form of voluntary curtailment is considered by us to be 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 (ie loss of production) or a time shift in production which results in no loss of overall production and therefore revenue to the customer. The question of materiality, willingness to participate and appropriate compensation levels to be applied by DNSPs within the test is important to clarify, as this will significantly impact the viability of this option.

The third form of load curtailment is also possible, particularly in remote areas of the network or areas which are either already constrained or for which a constraint is imminent. This form of curtailment is driven by the customer’s willingness to invest or afford the cost of network augmentation required to support their load request. Under this scenario, existing 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 progress. This is particularly relevant for large mining loads in remote 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 within the RIT-D.

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 publish, on an annual basis, deemed values and/or guidance 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.

It is also important to make clear that VCR calculations should only be 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 should not need to be calculated.

4.3. Other Parties Costs

Clarification is sought as to what costs should be included or excluded under this heading within the context of a DNSPs system, given that constraints solved by potential transmission upgrades and therefore potentially impacting the wholesale market are likely to be evaluated under the RIT-T as a Joint Planning project and therefore be excluded from evaluation under the RIT-D.

This situation may arise in the third form of Voluntary Load Curtailment discussed in our response within section 4.1 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, this augmentation enables the connection of larger levels of solar PV to become 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 4.5 below related to transfer capacity for relaxing of constraints on existing generation.

4.4. Timing of Expenditure

Consideration of how the timing of expenditure is handled by the RIT-D is a significant issue. For instance, if expenditure for one option occurs in the last year of the analysis period (e.g. year 10 in a 10 year analysis) and not at all in another option or be required outside the analysis window 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 as a benefit. We seek confirmation from the AER of their preferred method of dealing with this issue.

We also request the AER provide guidance of the minimum assessment period (we would suggest 10 years) to be used for the RIT-D, including guidance on the assessment of load at risk for incorporation of load forecasts. We note that the the National Electricity Rules (NER) requires

DNSPs to operate according to a minimum 5 year planning period, is difficult for us to provide a credible forecast beyond a 10 year horizon.

4.5. Load Transfer Capacity and capacity of Embedded Generators

We request guidance on how load transfer capacity should be explicitly considered within the analysis in a cost effective way other than by performing the test over an unreasonable number of years and therefore including changes in this capacity through changes in the timing of network augmentations. Load transfers should only be considered where spare capacity exists while remaining within the N-1 capacity of the adjacent stations.

Moreover, we do not consider that the description of "load transfer" on page 12 which states '...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' meets the generally understood definition of load transfer.

It should also be noted, for reasons of operational efficiency, DNSPs generally support a standardised range of conductor, transformer and substation sizes. Significant effort has been applied to the creation of standardised designs and equipment rationalisation in order to achieve the associated 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 generation 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 (ie 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 guidelines provide the opportunity for proponents to identify other relevant market benefits and costs and to seek written confirmation from the AER that they are acceptable. We would expect the RIT-D would operate in a similar manner, but request that the AER explain how the process would operate and what the likely response timeframes to such a request would be. This would be particularly important in the case of a RIT-D being performed for a customer initiated project.

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 for inclusion or exclusion within the RIT-D 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. Since these are effectively a transfer between market participants (as the costs of the transmission system do not change) these costs should be excluded from consideration under the RIT-D. Similarly, payments made to an embedded generator for provision of Network Support should have already considered avoided TUOS and therefore be included within the price offering used within the test. Note that if the embedded generation results 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 party's offer to generate would be.

5.2 Demand Side Participation (DSP)

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 should therefore operate in a similar manner to the current regulatory investment test, but 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 DNSPs 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. We consider that provision for recovery of any payment by DNSPs for DSP activities needs to be formalised by the AER, similar to the pass-through arrangements afforded to TNSPs within the NER for use of Network Support Arrangements. 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 DNSP 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. no incentive to pursue viable solutions). 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 Demand Side Participation (DSP) as the most efficient solution from a whole value chain viewpoint. To ensure efficient DSP is delivered in-line with the objectives of the National Electricity Law, the guidelines should 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 should be pre-determined, deemed values for generation and transmission set to equal the long run marginal cost of augmentation.

More generally, it is our view that the RIT-D should not favour any one technology, ownership structure or method of augmentation (ie the purpose of the RIT-D should be an objective test to identify a preferred option which resolves the identified constraint in a manner with 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 returns to 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 maintain existing system reliability levels over the long term. Without augmentation of the network in some form, this reliability becomes 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 in reliability 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 constraint on an overall region.

As such, we do not support any proposal to consider revision of the overall STPIS targets of 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 continue to be excluded from consideration under the RIT-D assessment. This is because 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 local 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 therefore, rather than the market price should be used within the RIT-D, 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 challenge by third parties, if the values to be applied within the RIT-D were published by the AER (together with 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 factor when comparing augmentation options due to:

- the average long run cost of generation being relatively small compared to the VCR (eg ~ $35 MWh compared with $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.

Our preference is not for the AER to specify a method by which the MWh value of losses is calculated as the preferred method used to calculate losses 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, we suggest 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, we support 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 by third parties for reasons which would be better resolved by relevant town planning and other development approval 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.

We would however 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 DNSPs on the ability of the proposed 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 and SA Power Networks 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.

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.

We request that the AER clarify its position on the inclusion of the DNSPs costs associated with proposals from third parties for "avoidance of doubt" and to reduce the risks of challenges alleging that the DNSP has not carried out the RIT-D analysis correctly. In particular, we seek clarification on the treatment of:

- costs of DNSPs in performing due diligence checks and administration of tenders and contracts with third parties;
- costs arising from the difference in the type of spending between DNSP augmentations (capital) and third party proposals (operational expenses);
- costs on network or non network options arising from environment considerations such as town planning or environmental authorities' criteria;
- costs of adjusting for differing financial risks between internal and third party proposals (we appreciate market performance risk is adjusted for through evaluation of VCR value); and

- the difficulties in quantifying financial risks such as contract cost variations between the performance of the RIT-D and the finalisation of contracts and financial stability of the third party.

In addition, the AER should confirm that where a third party has offered a price for Network Support, that said price may be deemed to reflect the true economic cost of the service for the party and therefore the DNSP does not have to further examine 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.

We are supportive of this proposal. Given the significant rate of change in the industry it is certainly conceivable that this flexibility may allow innovative and worth while projects to be considered.

However, given the time restrictions many RIT-D evaluations, particularly those that involve customer proposals will face, the AER needs to state the time frame within which they will make their decision on the relevancy of the costs and also on whether they will as a matter of policy make such determinations public. We support making these determinations public as this would increase the knowledge base of all DNSP's 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.

We oppose the treatment of the uncertainty in costs as outlined in the RIT-T guidelines due to the significant complexities and uncertainties involved in this approach. This point is explained further in response to Question 16 below.

We suggest that a better way is to develop a simple mechanism by which the materiality of the possible variation in costs to the determination of the preferred option can be assessed, and only if the variation has a material impact on the result should further analysis be required.

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. [page 22]

We accept the use of the WACC as the discount rate, with sensitivity analysis undertaken. We would request guidance be provided by the AER on the variations to be applied to the discount rate for the purpose of undertaking the sensitivity analysis.

Section 5.4 Methodologies for estimating costs

Question 16 & 17
We seek stakeholder views on the methodology that the RIT-D should specify for estimating costs. We are interested in whether stakeholders think the methodology should be adopted from those specified under the RIT-T and regulatory test

It is our position that the costing methodology proposed in the RIT-T is inappropriate for use by DNSPs in performing the RIT-D and that significant changes are required.

We would propose the use of a standard costing methodology based on historical unit or building block costs to estimate augmentation costs on an distribution system component/segment by component/segment basis with these unit costs set to a mid point of probability (same chance of exceeding as falling short). These costs should be the same as those used by the DNSP in preparing and submitting their Regulatory Reset proposals to the AER. In this way, the AER has already had an opportunity to review the reasonableness of the costing methodology employed by the DNSP through their Reset Determination.

The requirement to explicitly adjust these costs for externalities such as exchange rate, price of steel, price of labour or land etc. on an individual element by element basis as used by the RIT-T is extremely onerous given that a RIT-D conducted over a 10-15 year period with 3 or 4 credible options may entail multiple augmentations per option, each occurring in a different time period and therefore requiring a different evaluation of the risk of variation. The assessment of probabilities is also highly subjective and well outside of the technical competencies of the typical network planning department – it is therefore likely to fail the requirements of consistency and predictability under clause 5.17.1 (c) (3).

We recommend changing to evaluating the impact of different cost assumptions through sensitivity analysis rather than some highly complicated and arbitrary weighting system. This would allow a simple and consistent impact assessment to be conducted, 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).

We would support the AER providing guidance as to an appropriate variation, we suggest ±20% of the DNSP’s best cost estimate for use within the sensitivity analysis.

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.

In general, those examples contained within the RIT-D guidelines should be real world examples which show the comparison of multiple options. We believe that the following worked examples would be useful in both clarifying the thinking of the AER in the application of the test and in covering a substantial range of issues:

1. Substation on a radial line nearing the ultimate capacity of the line

Augmentation options to include installing peak lopping generation or a second line in year 1 with a further network upgrade required in year 5. This case is to illustrate:

- identification of constraints in terms of the DNSP's internal planning criteria;
- the interplay between Demand Management solutions and standard network upgrades;
- the treatment of reliability benefits and changes in losses;
- treatment of capital cost variations over augmentations separated in time;
- treatment of differences in transfer capacity between options.

2. Substation nearing capacity of its two transformers

Augmentation options to include upgrade of the transformers, a third transformer or a new substation on a radial line. This case is to illustrate:

- the treatment of losses and reliability benefits when moving load from a networked multi transformer substation to a single transformer substation on a radial line;
- the treatment of increased transfer capacity between substations.

3. Meshed Sub-transmission line overload under contingency conditions

Augmentation options to include upgrade of the existing line(s) or creation of a new line. This case is to illustrate:

- the treatment of losses and reliability benefits when dealing with meshed networks;

We would be willing to provide the AER with typical cases of the above including costs, forecasts and growth rates.

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.

We believe that additional clarification is required for the following:

1. Identification of parties to consult

Clause 5.17.4 (1) requires the DNSP to consult with all registered participants, AEMO, interested parties and non-network providers. We request clarification on how the DNSP is expected to identify and maintain the contact details of these groups so that they can be consulted; the assumption being that they have not registered on the individual DNSP's Demand Side Engagement Register. While a list of such Registered Participants is available on the AEMO website, it contains no contact details and contains parties who are unlikely to wish to receive such notifications (eg other DNSPs and unaffected TNSPs). It is our preference for DNSPs to notify the AER, AEMO and those contained within the DNSP's Demand Side Engagement Register of the publication of a RIT-D document. Should the AER wish this to be distributed more widely, the AER or AEMO should distribute a notice to further parties of the publication of the relevant document. We therefore request, the guidelines clarify those parties required to be notified under the RIT-D.

2. Identified Need

The DNSPs internal planning and load forecasting policies dictate the timing requirements of network augmentation to resolve a forecast network constraint. These policies are required to be published by the DNSP within the Distribution Annual Planning Report and consequently open to public comment and oversight by the AER. In addition, these policies are also subject to AER review during the Regulatory Reset process. Examples of areas where the current schedule 5.1 rules are unclear, relate to those constraints related to the determination of equipment ratings, the meeting of reliability standards and health and safety issues such as maintaining adequate line clearances and bushfire prevention policies.

3. Economic feasibility and Credible Option

The statement on page 10 of the RIT-T guidelines, that an option is "commercially feasible" if "…the option would be provided if it was the only available option", is not an appropriate test for the RIT-D to judge economic feasibility, given that most augmentations are driven by failure to meet regulatory reliability standards and therefore requiring something to be done.

We would suggest that in order for a proposal to be feasible, it should meet three criteria;

1. financial viability (i.e. be economically feasible);
2. technical viability (i.e. be capable of resolving the constraint); and
3. deliverability (i.e. be capable of being delivered within the timeframe required).

Should a proposal be incapable of meeting any of these areas, it should not be considered a viable or credible option for consideration within the test.

We believe that economic feasibility and the overall credibility of an option or proposal (as outlined above), should be assessed with regard to other available augmentation options. We request that the AER develop examples or provide guidance within the guidelines with regard to when proposals or options can be considered by DNSPs to be unfeasible or not credible.

4. Scope of the examples

The examples within this section of the RIT-T guidelines are focused on the wholesale electricity market and are therefore not directly applicable to the RIT-D, for the reasons previously stated. The examples within the RIT-D guidelines therefore need to represent real world examples and scenarios as they apply to DNSPs.

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.

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

Section 6.2 Application of guidelines

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).

It is our preference that a project should be evaluated under the old regulations where:

- the first augmentation in the project is expected to commence construction within 24 months of the RIT-D coming into force; or
- a project evaluation has been published under the former regulations prior to the RIT-D commencement date; or
- a document other than an annual planning report has been published informing the public of the project. In the South Australia jurisdiction, these documents are the Reasonableness Test (i.e. screening test) or a Request For Proposals; or
- the project is included in the list of projects subject to the former Reg Test submitted to the AER prior to 31 December 2013.

Section 6.3 Process to be followed

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.

We note the following areas where guidance on the RIT-D, rather than the RIT-T (which we consider is the intended subject of the question), would be useful.

1. Flow charts illustrating progress

In addition to the existing combined flow chart showing how each category of augmentation progresses through the RIT-D process, it would be useful for the AER to provide some sample flow charts illustrating how small, medium and large projects are intended to flow through the process. This would simplify explanations to the general public, interested third parties and management of how the steps in the process combine for each scale of project.

2. Screening for non network options

We believe that given the rapid change of technology in this area, guidance in this area should not be formalised by the AER as such guidance is highly likely to become redundant over time.

If the AER does wish to provide guidance, we suggest that it limit itself to specifying the minimum range of technologies that should be considered in the Screening Test.

3. Content of the Notice under clause 5.17.4 (d)

We would appreciate an example of the contents of this Notice given the requirement under the clause 5.17.1 (c) (2) of the NER of proportionality.

We also request clarification of whether or not the Notice and Draft Project Assessment Report (DPAR) could be the same in the cases where the project is large enough to require a DPAR to be produced (i.e. > $10 million) but the Screening Test Notice suggested no viable non-network solutions. If not, can the AER explain what differences should exist between the Notice and the DPAR.

4. Timing

We believe it would be useful for the AER to provide guidance regarding the impact of changes to project timings on the RIT-D assessment process, as well as confirmation that minor delay of a project (eg 1 or 2 years) , as a result of other factors, would not require a new RIT-D to be completed.

Section 6.4 Estimating market costs

Question 23
We seek stakeholder views on what methodologies the RIT-D application guidelines should adopt for valuing market benefits.

We believe that the question of materiality of benefits is likely to be the major issue and therefore seek clarification of at what point a “benefit” can be considered to be material or immaterial to the outcome of the RIT-D and therefore excluded from being calculated.

A second issue is where an augmentation provides benefits in excess of a “minimum change”, for example, by installing a second transformer from day one at a new substation. We believe that this is best justified when the additional benefits outweigh the additional costs. In terms of what constitutes the minimum augmentation requirements, the relevant DNSP should be entitled to rely on individual company planning policies that dictate the range of upgrades / new equipment that will be supported by a project. These policies are published in the DAPR and are open to public comment and open to review by the AER as part of the Regulatory Reset process.

Section 6.5 Dispute resolution

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.

We believe that the dispute resolution process provided within the Rules are sufficiently explicit and satisfactorily explain the process to be followed.