grid australia
BACKBONE OF THE NEM

18 July 2013

Mr Chris Pattas
General Manager
Network Operations and Development
Australian Energy Regulator
GPO Box 5220
MELBOURNE VIC 3001

Dear Chris

Draft RIT-D and application guidelines

Grid Australia is pleased to make this submission to the Australian Energy Regulator (AER) in relation to its draft Regulatory Investment Test for Distribution (RIT-D), and associated draft Application Guidelines.

Given the parallels between the RIT-D and the Regulatory Investment Test for Transmission (RIT-T) applying to TNSPs, the guidance provided by the AER in relation to the RIT-D has implications for the RIT-T. Grid Australia is therefore particularly concerned to ensure that the AER's Application Guidelines for the RIT-D are clear, comprehensive and consistent with existing RIT-T guidance, where relevant.

Grid Australia has identified three concerns with the AER's draft RIT-D Application Guidelines. These are explained fully in the attachment to this letter. The key concern relates to the proposed treatment of the costs and benefits of non-network options.

The AER has set out two alternative approaches to valuing the payments made to customers to reduce their load under a demand-side option. One approach is that which is currently adopted under the RIT-T; i.e. including these costs as part of the direct cost of the option. The alternative approach is to exclude these costs from the direct cost, but to include the increase in voluntary load curtailment as a (negative) market benefit.

The alternative approach put forward by the AER:

- raises informational difficulties in practice, as it requires separating out payments made by demand-side aggregators to end customers, which can be expected to be commercially sensitive and not known with certainty at the time the RIT-T or RIT-D is applied;

- will not be equivalent to the contract cost approach in situations where there are availability payments, leading to the potential for dispute on which approach to use;

- is not comprehensive, as no guidance is provided on how to treat demand-side options which involve embedded generation as well as demand-reduction; and

- raises questions in relation to the approach that should be taken to the costs and benefits of network support contracts offered by embedded generators.

It is important that the AER Guidelines are clear and definitive in relation to how the costs and benefits of non-network options should be treated in the RIT-D (and, by implication, in the RIT-T).

Grid Australia strongly supports continuing with the current approach of including the full contract costs of non-network options (both demand-side and generation options) as part of the direct costs of the option. This approach is straightforward and does not require the NSP to 'second-guess' the commercial arrangements underlying non-network options. As a consequence it is less open to interpretation and dispute.

Given the AER's view that its two suggested approaches are equivalent, there appears to be no benefit in proposing an alternative approach which is more complex to apply, which suffers from informational shortcomings, and which has the potential to lead to disputes.

Grid Australia's concerns in relation to the AER's guidance for demand-side options are discussed in more detail in the remainder of this submission.

In addition, this submission covers two other issues which Grid Australia believes the AER should address as it finalises the RIT-D and associated Application Guidelines, namely:

- ensuring that NSPs are not precluded from adopting a robust methodology to quantify option value, where it is proportionate to do so; and

- providing clear guidance on the treatment of strategic land and easement acquisitions in the RIT-D/ RIT-T and recognising that, if these are to be included, it is the opportunity value of the land that should be included in the cost of an option.

Finally, Grid Australia supports the AER's view that the circumstances which would require a re-application of the RIT-D are likely to be limited.

For any further information required in relation to the issues raised above, please contact Anthony Englund on (02) 9284 3148 or me on (08) 8404 7983.

Yours sincerely

Rainer Korte

Rainer Korte
Chairman
Grid Australia Regulatory Managers Group

grid australia
BACKBONE OF THE NEM

RIT-D and Application Guidelines

Response to AER Draft Decision

18 July 2013

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

Table of Contents

1. Summary

Grid Australia welcomes the opportunity to make this submission to the Australian Energy Regulator (AER) in relation to its draft Regulatory Investment Test for Distribution (RIT-D), and associated draft Application Guidelines.

Given the parallels between the RIT-D and the Regulatory Investment Test for Transmission (RIT-T) applying to TNSPs, the guidance provided by the AER in relation to the RIT-D has implications for the RIT-T. Grid Australia is therefore particularly concerned to ensure that the AER's Application Guidelines for the RIT-D are clear, comprehensive and consistent with existing RIT-T guidance, where relevant.

Grid Australia's key concern with the AER's draft RIT-D Application Guidelines relates to the proposed treatment of the costs and benefits of non-network options.

The AER has set out two alternative approaches to valuing the payments made to customers to reduce their load under a demand-side option. One approach is that which is currently adopted under the RIT-T; i.e. including these costs as part of the direct cost of the option. The alternative approach is to exclude these costs from the direct cost, but to include the increase in voluntary load curtailment as a (negative) market benefit.

The alternative approach put forward by the AER:

- raises informational difficulties in practice, as it requires separating out payments made by demand-side aggregators to end customers, which can be expected to be commercially sensitive and not known with certainty at the time the RIT-T/RIT-D is applied;
- will not be equivalent to the contract cost approach in situations where there are availability payments, leading to the potential for dispute on which approach to use;
- is not comprehensive, as no guidance is provided on how to treat demand-side options which involve embedded generation as well as demand-reduction; and
- raises questions in relation to the approach that should be taken to the costs and benefits of network support contracts offered by embedded generators.

It is important that the AER Guidelines are clear and definitive in relation to how the costs and benefits of non-network options should be treated in the RIT-D (and, by implication, in the RIT-T).

Grid Australia strongly supports continuing with the current approach of including the full contract costs of non-network options (both demand-side and generation options) as part of the direct costs of the option. This approach is straightforward and does not require the NSP to 'second-guess' the commercial arrangements underlying non-network options. As a consequence it is less open to interpretation and dispute.

Given the AER's view that its two suggested approaches are equivalent, there appears to be no benefit in proposing an alternative approach which is more complex to apply, which suffers from informational shortcomings, and which has the potential to lead to disputes.

Grid Australia's concerns in relation to the AER's guidance for demand-side options are discussed in more detail in the remainder of this submission.

In addition, this submission covers two other issues which Grid Australia believes the AER should address as it finalises the RIT-D and associated Application Guidelines, namely:

- ensuring that NSPs are not precluded from adopting a robust methodology to quantify option value, where it is proportionate to do so; and
- providing clear guidance on the treatment of strategic easement and land acquisitions in the RIT-D/ RIT-T and recognising that, if these are to be included, it is the opportunity value of the land that should be included in the cost of an option

Finally, Grid Australia supports the AER's view that the circumstances which would require a re-application of the RIT-D are likely to be limited.

2. Treatment of the Costs and Benefits of Demand-Side Options

The AER's draft Application Guidelines suggest that the costs associated with demand-side options can be treated in two alternative ways under the RIT-D.

Specifically, rewards or inducements paid to consumers for voluntary load curtailment under a demand-side option could be counted as either:

- part of the cost of the demand-side option ('Approach 1'); or
- a negative market benefit of the option – specifically through valuing the resulting increase in voluntary load curtailment by reference to the amount paid to customers to reduce their load ('Approach 2'). Under this approach, these payments would not then also be included as part of the cost of the demand-side option.

The AER suggests that these two approaches are equivalent, and focuses on Approach 2 in its worked examples.

Grid Australia has the following concerns with the AER's draft guidance:

- in practice there are likely to be informational difficulties associated with Approach 2, requiring the exercise of judgement by the NSP which may in turn lead to dispute;

- the two approaches will not always be equivalent, which may lead to the potential for dispute over which approach to adopt;

- the AER's discussion of Approach 2 and the associated worked examples are not comprehensive, and, in particular, do not provide guidance on how to treat demand-side options which involve embedded generation as well as demand-reduction; and

- the AER's suggested Approach 2 potentially leads to a different treatment under the RIT-T/RIT-D of the costs of embedded generation when arranged via a demand-side aggregator compared to where contracted directly by the NSP.

The lack of clear and definitive guidance by the AER in the draft RIT-D Guidelines in relation to the treatment of non-network options introduces confusion and, if not clarified, raises the risk of future disputes. Grid Australia therefore considers it of key importance that the final AER RIT-D Guidelines provide clear and unambiguous guidance on this issue. The AER should also confirm in its final RIT-D Guidelines the approach to treating the costs of generation network support options under the RIT-D, which is now potentially unclear in the light of the draft guidance provided for demand-side options.

The following sub-sections discuss each of the above points in more detail.

2.1 The AER has proposed two alternative approaches to treating demand-side options

Currently under the RIT-T the total contract costs associated with non-network options (both demand-side options and generator network support options) are included as part of the 'direct cost' of those options. The AER has previously clarified that the costs of non-network options should be based on the expected contract costs for these options.[1]

EnerNOC has suggested that payments to consumers to reduce their demand represent a transfer, and therefore should not be included as part of the cost of a demand-side option under the RIT-T.[2] In its submission on the AER's RIT-D issues paper, EnerNOC commented that if the availability and dispatch payments made by the DNSP are to be counted as an economic cost, then the availability and dispatch payments received by participating customers should be counted as an economic

1 See: AER, Regulatory Test Version 3, Final Decision, November 2007, p. 39; and AER, *Regulatory Test Application Guidelines, Version 01*, November 2007, p. 17.

2 EnerNoc, *Dispute notice regarding SA-Vic Interconnection Upgrade RIT-T*, 26 February 2013.

benefit.[3] In contrast, the Energy Networks Association (ENA), amongst others, has asked the AER to clarify that payments to demand side aggregators should be included in the RIT-D, as the bulk of these payments are compensation to the aggregators for the real costs of arranging the demand side response.[4] The ENA has also asked the AER to confirm that where a third party has offered a price for Network Support that price is deemed to reflect the true economic cost of the service to the party and the DNSP does not have to investigate further.

Clearly the treatment of non-network options under the RIT-D (and, by implication, the RIT-T) is an area in which further guidance from the AER appears warranted. However the AER's Draft Guidelines increase the confusion around this issue, and, as they currently stand, do not provide a single, clear approach to how the costs and benefits of demand-side options should be assessed. Rather, the Draft Guidelines suggest that rewards or inducements paid to consumers for voluntary load curtailment under a demand-side option could be counted as either:[5]

- part of the a cost of the demand-side option (Approach 1); or
- a negative market benefit of the option – specifically through valuing the increase in voluntary load curtailment by reference to the amount paid to customers to reduce their load (Approach 2).

The AER states that under Approach 2 payments to consumers for curtailment do not need to be counted again as part of the costs of the option.[6] As a consequence, under Approach 2 costs of the demand-side option would be limited to the commission or fees charged by the demand-side aggregator or relevant energy service business,[7] including the margin of the demand-side option provider.[8]

The AER suggests that the two proposed approaches are equivalent.

Grid Australia's understanding of the way in which the costs and benefits of demand-side options are treated under each of the two approaches proposed by the AER is illustrated in Figure 2.1.

---

3 EnerNOC, *Submission on the Regulatory Investment Test for Distribution issues paper*, 25 February 2013, p. 7.

4 Energy Networks Association, *Issues Paper – Regulatory investment test for distribution (RIT-D) application guidelines*, p.6 and p. 10.

5 AER, *Draft Regulatory Investment Test for Distribution*, Application Guidelines, June 2013, p. 41.

6 AER, *Draft Regulatory Investment Test for Distribution*, Application Guidelines, June 2013, p. 40.

7 AER, *Draft Regulatory Investment Test for Distribution*, Application Guidelines, June 2013, p. 41.

8 AER, *Draft Regulatory Investment Test for Distribution*, Application Guidelines, June 2013, p. 52.

Figure 2.1 - The two approaches to treating demand-side options proposed by the AER

AER Proposed Approach	Costs	Market Benefits
Approach 1	Aggregator costs Customer payments	
Approach 2	Aggregator costs	Value of increased voluntary load curtailment*

** As reflected in payments to customers for demand reduction.*

2.2 Worked example of the AER's guidance

The worked examples provided in the AER's Draft Guidelines do not provide a comprehensive picture of the treatment of both the costs and benefits of demand-side options, focusing instead only on how to treat payments for load reduction. There are also inconsistencies between the worked examples, as well as between the examples and the explanatory text in the Guidelines.

Box 2.1 below contains a worked example of the AER's two approaches, which has been modified from the AER's 'Example 16' in the Draft RIT-D Application Guidelines in order to cover both the costs and benefits of the demand-side option.

Box 2.1 - Two approaches proposed by the AER to include the cost of demand-side options

Assume that load on a particular network is expected to reach 201 MW but that the network's capacity is only 200 MW. Assume also that customers value involuntarily curtailed load at $45,000/MWh (this value represents the value of customer reliability (VCR) for customers).

A demand-side credible option involves paying a demand aggregator $1,500/MWh to curtail load by 1 MW during 100 pre-notified hours of critical peak periods each year, of which the aggregator in turn pays $1,000/MWh to a group of large electricity consumers to curtail their load during these periods, (i.e. the aggregator retains $500/MWh).

In the base case:

- demand exceeds supply by 1 MW for 100 hours a year
- value of voluntary load curtailment: $0
- value of involuntary load curtailment: 1 MW x 100 hours x $45,000/MWh = $4,500,000 per year

Using Approach 1, in the state of world with the credible option:

- demand is curtailed by 1 MW for 100 hours a year so that it does not exceed system supply
- full contract cost included in the costs of the demand-side option: $1,500/MWh x 1 MW x 100 hours = $150,000
- value of voluntary load curtailment: $0
- value of involuntary load curtailment: $0
- net benefit of demand-side option: [9] $4,500,000 - $150,000 = $4,350,000 per year

Using Approach 2, in the state of world with the credible option:

- demand is curtailed by 1 MW for 100 hours a year so that it does not exceed system supply
- only aggregator costs included in the costs of the demand-side option: $500/MWh x 1 MW x 100 hours = $50,000
- value of increased voluntary load curtailment (as reflected in payments to customers): $1,000/MWh x 1 MW x 100 hours = $100,000
- value of involuntary load curtailment: $0
- net benefit of demand-side option: $4,500,000 - $50,000 - $100,000 = $4,350,000 per year

The two approaches proposed by the AER yield the same result under these assumptions.

The worked example in Box 2.1 highlights several inconsistencies in the AER's own worked examples:

- Under Approach 2 there is no need to value voluntary load curtailment at the wholesale market price. Instead, the voluntary load curtailment arising as a result of the demand-side option is valued at the amount paid by the demand aggregator to customers. This is because the demand reduction is the result of the demand management option, rather than being a customer response to market prices.

9 Note: In this and the later examples presented in this submission, Grid Australia has assumed all other market benefit categories are zero in order to simplify the example.

- There is an inconsistency in the AER's worked examples on this point. Example 15 of the Draft Guidelines does not value voluntary load curtailment at the wholesale market price, whereas Example 16 does (incorrectly).

- The AER's Example 15 in the Draft Guidelines refers to the 'allocation' of the demand-side payments to customers across energy, transmission and distribution activities. There is no discussion in the Guidelines of the basis on which this allocation should be made. More fundamentally, there is no discussion of the rationale for such an allocation, which appears unnecessary.

- Again, there appears to be an inconsistency in the AER's worked examples. Example 16 of the Draft Guidelines does not involve this allocation, whereas Example 15 does (incorrectly).

- The allocation of demand-side payments means that Approach 2 suffers from an 'apples with oranges' comparison, given that the reduction in involuntary load curtailment is valued at the VCR, which is a system-wide estimate.

Grid Australia also notes that the AER's Approach 2 may in some circumstances be inconsistent with the wording of the NER, depending on how reliability standards are expressed in a particular jurisdiction. Specifically, clause 5.17.1(c)(5) of the NER states that where the identified need is for reliability corrective action, the quantification of both voluntary and involuntary load curtailment only applies insofar as the market benefit delivered by that credible option exceeds the minimum standard required for reliability corrective action. Where voluntary load curtailment under the demand-side option is required in order to meet the reliability standard, but does not result in the target being exceeded, the wording of the NER appears to preclude the quantification of the benefit associated with voluntary load reduction.[10]

2.3 Informational difficulties with Approach 2

In practice, there are substantial informational difficulties associated with the AER's Approach 2. This approach relies on information regarding the business model of the provider of the demand-reduction service; i.e. the split between the amount of the contracted demand management payment the demand aggregator will pay to end-use customers and the amount (including margin) that is retained by the demand aggregator. This breakdown can be expected to be commercially sensitive, and dependent on particular circumstances[11], and so is unlikely to be readily available. Indeed, difficulties with obtaining a robust estimate of the real resource costs

[10] The same NER provision means that it will also not always be the case that the negative contribution to the market benefits of the demand-side option (via increased voluntary load curtailment) will be more than offset by a positive contribution to market benefit caused by a reduction in the amount of involuntary load shedding that would otherwise occur. Where the reduction in involuntary load shedding meets, but does not exceed, minimum standards it would not be quantified under the RIT-D.

[11] Indeed, in its Dispute Notice regarding the SA-Vic Interconnection upgrade, EnerNOC noted that the exact amount passed through to participating electricity consumers varies from programme to programme depending on the difficulty of customer acquisition in the relevant region (although it noted that it was typically around 50%).

associated with non-network options previously led the AER to focus on the contract cost as representing the appropriate cost to include for non-network options (i.e. Approach 1 above).

2.4 The two approaches need not be equivalent

The two approaches proposed by the AER will also not always be equivalent. By suggesting that either approach can be used, the AER is therefore opening up be possibility of disputes as to which approach should be adopted.

Consider an example where payments by the demand-side aggregator to consumers include a fixed (availability) payment, in addition to load reduction payments (i.e. a $/MWh payment). In this circumstance, the sum of the costs of the demand-side option plus the negative benefit from voluntary load reduction will be less under Approach 2 than under Approach 1, as the availability payments to consumers will not be captured under Approach 2. This is illustrated in Box 2.2 below.

Availability payments from demand aggregators to consumers may be a transfer. However they are more likely to be to compensate customers for the costs that they incur in providing demand response, such as the costs of implementing systems and processes. This is particularly the case where the market for demand-response services is competitive.

The AER's Approach 2 would not capture these real resource costs. A possible modification of Approach 2 would be to allow these costs to be captured as an increase in 'the costs to other parties' under the RIT-D. However the AER has provided no guidance on this issue. Moreover, if this modification was adopted, it would then be necessary for the NSP to also obtain information not only on the expected payments from demand aggregators to end-customers, but also on the breakdown of those payments between availability payments and load reduction payments. As noted above, this information is unlikely to be directly available (as it will be commercially sensitive), and will also be uncertain at the time at which the RIT-D or RIT-T is applied (as this is prior to customers being signed-up to the demand-side program).

Box 2.2 - The two approaches need not be equivalent

As in Box 2.1, assume that load on a particular network is expected to reach 201 MW but that the network's capacity is only 200 MW. Assume also that customers value involuntarily curtailed load at $45,000/MWh.

However, in contrast to Box 2.1, assume that a demand-side credible option involves paying a demand aggregator the following:

- $500,000 per year as an availability payment, which it passes on in full to a group of large electricity consumers; and
- $1,500/MWh to curtail load by 1 MW during 100 pre-notified hours of critical peak periods each year, of which it pays $1,000/MWh to a group of large electricity consumers to curtail their load during these periods, (i.e. the aggregator retains $500/MWh).

In the base case:

- demand exceeds supply by 1 MW for 100 hours a year
- value of voluntary load curtailment: $0
- value of involuntary load curtailment: 1 MW x 100 hours x $45,000/MWh = $4,500,000 per year

Using Approach 1, in the state of world with the credible option:

- demand is curtailed by 1 MW for 100 hours a year so that it does not exceed system supply
- full contract cost included in the costs of the demand-side option: $500,000 + $1,500/MWh x 1 MW x 100 hours = $650,000
- value of voluntary load curtailment: $0
- value of involuntary load curtailment: $0
- net benefit of demand-side option: $4,500,000 - $650,000 = $3,850,000 per year

Using Approach 2, in the state of world with the credible option:

- demand is curtailed by 1 MW for 100 hours a year so that it does not exceed system supply
- only aggregator costs included in the costs of the demand-side option: $500/MWh x 1 MW x 100 hours = $50,000
- value of increased voluntary load curtailment (as reflected in payments to customers): $1,000/MWh x 1 MW x 100 hours = $100,000
- value of involuntary load curtailment: $0
- net benefit of demand-side option: $4,500,000 - $50,000 - $100,000 = $4,350,000 per year

The two approaches proposed by the AER are not equivalent under these assumptions.

2.5 The AER's discussion of approach 2 is not comprehensive

The AER's discussion of its alternative treatment of demand-side options (Approach 2) is also not comprehensive.

In many circumstances, demand-side reductions offered by an aggregator will include payments to customers to use their own embedded generation at times of peak demand on the network (thereby reducing network demand), in addition to payments to customers to curtail their load at peak times. The AER's draft guidance does not cover the appropriate treatment of the costs and benefits of a demand-side option in this case.

The AER's proposed Approach 2 could be extended to also cover demand-side options involving payments to embedded generators. In this case:

This approach is outlined in Box 2.3.

In relation to the treatment of the additional fuel costs, Grid Australia notes that 'changes in fuel costs' is not a market benefit category automatically included in the RIT-D (in contrast to the RIT-T), and so DNSPs may need to obtain prior written approval from the AER to include this market benefit.

Under this modified Approach 2 the informational difficulties faced by the NSP are further compounded, as now the NSP needs to identify both payments from a demand-aggregator to end-use customers to reduce their load and payments by a demand-aggregator to customers to use their on-site generation.

Any 'availability payment' made to embedded generators by the demand aggregator would again not be captured as a market cost or benefit under this approach. This would again lead to different net benefits being calculated depending on whether the AER's Approach 1 or Approach 2 is adopted.

Grid Australia considers that if the AER continues to propose the treatment of demand-side options under 'Approach 2', then the guidance provided needs to be expanded to include how to apply this approach in the context of an aggregator making payments to customers to use their own embedded generation, as well as to reduce their demand.

Box 2.3 - Two approaches proposed by the AER – embedded generation

As in Box 2.1, assume that load on a particular network is expected to reach 201 MW but that the network's capacity is only 200 MW. Assume also that customers value involuntarily curtailed load at $45,000/MWh.

However, in contrast to Box 2.1, assume that a demand-side credible option involves paying a demand aggregator the following:

- $1,500/MWh to curtail load by 0.5 MW during 100 pre-notified hours of critical peak periods each year, of which it pays $1,000/MWh to a group of large electricity consumers to curtail their load during these periods (i.e. the aggregator retains $500/MWh); and
- $2,000/MWh to provide 0.5 MW of load reduction during 100 pre-notified hours of critical peak periods each year, of which it pays $1,500/MWh to a group of large electricity consumers who own embedded generators (i.e. the aggregator retains $500/MWh).

In the base case:

- demand exceeds supply by 1 MW for 100 hours a year
- value of voluntary load curtailment: $0
- value of involuntary load curtailment: 1 MW x 100 hours x $45,000/MWh = $4,500,000 per year
- fuel costs: $0

Using Approach 1, in the state of world with the credible option:

- demand is curtailed by 0.5 MW and 0.5 MW of generation support is provided for 100 hours a year so that demand does not exceed system supply
- full contract cost included in the costs of the demand-side option: $1,500/MWh x 0.5 MW x 100 hours + $2,000/MWh x 0.5 MW x 100 hours = $175,000
- value of voluntary load curtailment: $0
- value of involuntary load curtailment: $0
- net benefit of demand-side option: $4,500,000 - $175,000 = $4,325,000 per year

Using Approach 2, in the state of world with the credible option:

- demand is curtailed by 0.5 MW and 0.5 MW of generation support is provided for 100 hours a year so that demand does not exceed system supply
- only aggregator costs included in the costs of the demand-side option: $500/MWh x 0.5 MW x 100 hours + $500/MWh x 0.5 MW x 100 hours = $50,000
- value of increased voluntary load curtailment (as reflected in payments to customers): $1,000/MWh x 0.5 MW x 100 hours = $50,000
- value of involuntary load curtailment: $0
- fuel costs: $1,500/MWh x 0.5 MW x 100 hours = $75,000
- net benefit of demand-side option: $4,500,000 - $50,000 - $50,000 - $75,000 = $4,325,000 per year

2.6 Treatment of generation network support options

Finally, Grid Australia notes that the AER's draft guidance raises a wider question regarding the appropriate treatment of the costs of other non-network options, and in particular the treatment of options involving network support payments to embedded generation.

Currently, under the RIT-T the direct costs of generator network support options are taken as the contract costs associated with those options. This is consistent with previous AER guidance,[12] and means that the NSP is not required to investigate the proposed contract costs to try to distinguish between elements of market costs and market transfers between parties. That is, the contract cost is taken to be representative of the true economic cost of the option.

As highlighted in the previous section, demand-side options obtained via an aggregator can be expected to involve both payments to customers to reduce demand, and payments to customers to use their own embedded generation at times of peak demand. Applying the AER's Approach 2 to these options (as discussed in the previous section), but continuing to apply the full contract cost of options where the embedded generator contracts directly with the NSP (i.e. Approach 1), would led to different valuations under the RIT-D of options with essentially the same cost structure. This is illustrated in Box 2.4, where the only difference between the options is their contractual arrangements (i.e. one involves contracting with an aggregator and the other contracting with the NSP directly).

Grid Australia considers that the AER should provide clear guidance under the RIT-D for the treatment of the costs of generator network support options, and that the guidance provided for generator network support and demand-side options (which may also involve embedded generation) should be consistent.

12 See: AER, Regulatory Test Version 3, Final Decision, November 2007, p. 39; and AER, *Regulatory Test Application Guidelines, Version 01*, November 2007, p. 17.

Box 2.4 - Approach 2 – Embedded Generation: Aggregator vs. Contracted Directly with NSP

As in Box 2.1, assume that load on a particular network is expected to reach 201 MW but that the network's capacity is only 200 MW. Assume also that customers value involuntarily curtailed load at $45,000/MWh.

However, assume that there are two demand-side credible options that have identical underlying costs except that one involves embedded generation arranged via an aggregator and one involves embedded generation contracted directly with the NSP. Specifically, the payments under the two options are summarised below:

- embedded generation arranged via an aggregator (credible option 1):
  - $500,000 per year as an availability payment, which it passes entirely on to a group of large electricity consumers; and
  - $2,000/MWh to provide 1 MW of load reduction during 100 pre-notified hours of critical peak periods each year, of which the aggregator pays $1,500/MWh to a group of large electricity consumers who own embedded generators (i.e. the aggregator retains $500/MWh).
- embedded generation contracted directly with the NSP (credible option 2):
  - $500,000 per year as an availability payment; and
  - $2,000/MWh to provide 1 MW of load reduction during 100 pre-notified hours of critical peak periods each year, of which $1,500/MWh reflects the embedded generator's underlying fuel costs.

In the base case:

- demand exceeds supply by 1 MW for 100 hours a year
- value of voluntary load curtailment: $0
- value of involuntary load curtailment: 1 MW x 100 hours x $45,000/MWh = $4,500,000 per year
- fuel costs: $0

In the state of world with credible option 1 (using Approach 2):

- only aggregator costs included in the costs of the demand-side option: $500/MWh x 1 MW x 100 hours = $50,000
- fuel costs: $1,500/MWh x 1 MW x 100 hours = $150,000
- value of involuntary load curtailment: $0
- net benefit of demand-side option: $4,500,000 - $50,000 - $150,000 = $4,300,000 per year

In the state of world with credible option 2 (using Approach 1):

- full contract cost included in the costs of the demand-side option: $500,000 + $2,000/MWh x 1 MW x 100 hours = $7000,000
- value of involuntary load curtailment: $0
- net benefit of demand-side option: $4,500,000 - $700,000 = $3,800,000 per year

2.7 Summary: need for clear, definitive guidance

Grid Australia considers it imperative that the AER's guidance is clear and definitive in relation to how the costs and benefits of non-network options should be treated in the RIT-D (and, by implication, in the RIT-T). This is particularly important given the potential for dispute in relation to the treatment of non-network options. Several stakeholders have called on the AER to provide clear guidance on this issue.

The AER's draft guidance currently falls short of being clear and definitive, and risks introducing considerable uncertainty in relation to the appropriate treatment of both demand-side and generation options under the RIT-D and the RIT-T.

Grid Australia strongly supports continuing with the current approach under the RIT-T of including the full contract costs of non-network options (both demand-side and generation options) as part of the direct costs of the option (i.e. Approach 1). This approach is straightforward and does not require the NSP to 'second-guess' the commercial arrangements underlying proposed non-network options. As a consequence, it is less open to interpretation and, therefore, dispute.

The AER appears to be of the view that its two suggested approaches are equivalent, rather than suggesting one is theoretically superior than the other. In this context there appears to be no benefit in the AER proposing an alternative approach, which is more complex to apply comprehensively, and which suffers from informational shortcomings.

Grid Australia recognises the argument that an element of the payment made to both demand-side aggregators and directly to embedded generators may reflect a 'transfer' element between parties in the NEM, which should be excluded from consideration under the RIT-D or RIT-T. However, consistent with the AER's previous guidance, Grid Australia considers that if the market for demand management and generation support services is sufficiently competitive, then the contract costs should reflect the underlying efficient economic costs of providing these services. In the case of payments to customers to reduce their consumption, as the AER has recognised in its discussion in relation to the RIT-D, this payments reflects the cost to customers associated with forgoing their consumption, rather than a 'transfer' which need not be captured in the analysis.[13] TNSPs' recent experience with the RIT-T has indicated that there is substantial competition to provide non-network services, with a number of non-network offers being received in response for requests for tender.

3. Additional issues

3.1 Option value and the treatment of uncertainty

The AER's draft Application Guidelines include a discussion of both the treatment of uncertainty under the RIT-D analysis and option value.

The NER include option value as a category of market benefit that can be included under the RIT-D and RIT-T, where material. Option value is the additional value captured by being able to modify the timing or nature of an investment in response to new information, in a situation in which there is uncertainty. The treatment of uncertainty and the assessment of option value are therefore concepts that are directly interlinked.

[13] This 'cost' to customers is captured where the direct cost of the demand-side option includes the payments made to customers (i.e. Approach 1).

Statements by the AER in both its Draft RIT-D Guidelines and the accompanying Explanatory Statement show a fundamental misunderstanding of the nature of the real options assessment required to quantify option value. For example, the AER Draft RIT-D Guidelines state that: 'We believe that appropriate identification of credible options is capable of capturing any option value, thereby meeting the requirement to consider option value as a class of market benefit under the RIT-D.' [14]

Grid Australia does not agree that option value and an appropriate treatment of uncertainty will necessarily be captured by considering a range of options under a spreadsheet RIT-T analysis. Work previously commissioned by Grid Australia (which informed the RIT-T consultation process) highlighted the techniques that can be used to quantify option value – which go substantially beyond the identification of different options.[15]

The substantial work required to quantify option value will not be proportionate for all RIT-T or RIT-D assessments. However the wording of the RIT-T Guidelines currently provides flexibility for TNSPs to quantify option value, where the analysis required to do so is considered proportionate. Grid Australia considers that, similarly, the AER's RIT-D Guidelines should not preclude the quantification of option value via appropriate techniques as part of a RIT-D assessment, in circumstances where such analysis would be proportionate.

3.2 Treatment of the costs of strategic acquisitions

The AER states that costs incurred before the RIT-D process is finalised 'would typically be treated as sunk costs and therefore excluded from the cost benefit analysis'.[16] However the AER has highlighted that the treatment of the strategic acquisition of easements is one which it intends to 'monitor', and which it considers to be 'an issue under the RIT-T'.[17]

Grid Australia considers that the same principles should be applied under the RIT-D and RIT-T to the treatment of the cost of strategic acquisitions, whether those acquisitions relate to easements or land.

3.2.1 Justification of strategic acquisitions as prudent and efficient

Strategic acquisitions relate to the purchase of either land or easements ahead of the time at which they are needed. Such strategic purchases may be justified as prudent and efficient, where the expected future development of land (for example, for residential development) means that it would either not be possible, or would be substantially more expensive, to acquire the easements and/or land closer to the time of the associated investment. In the absence of an earlier, strategic acquisition, either (i) the cost of acquiring the easements/ land at the time the investment is

---

[14] AER *Draft RIT-D Application Guidelines*, p. 59. See also AER *Explanatory Statement*, p. 21.

[15] http://www.nera.com/nera-files/PUB_GridAustralia_0511.pdf

[16] AER *Explanatory Statement*, p. 22.

[17] AER *Explanatory Statement*, p. 22.

required would be substantially higher; or (ii) the costs of the network investment itself would be substantially higher (as an alternative route would need to be selected, or parts of the development may need to be located underground). As a consequence, the costs that customers would bear in relation to the investment would be higher in the absence of the strategic purchase.

In some circumstances, expected future expansion or replacement of an existing network element can only occur on land which is adjacent to existing facilities (for example, the future expansion of a transmission substation), and so substantive uncertainty about the availability or cost of that land in future may justify its strategic purchase.

Although the detailed nature and/or timing of an investment may not be known at the time at which strategic acquisitions are made, in many cases the broad location of the investment can be foreseen. Similarly, closer to the time of the investment it may be possible to identify non-network options (which would be assessed via the RIT-T or RIT-D process). However, in many cases such options will only delay the need for the network investment, rather than replace it (for example, where eventual replacement of a transmission line will be required due to asset condition).

Where an NSP considers that it is prudent and efficient to undertake a strategic purchase or either easements of land, this expenditure is included in its capital expenditure forecast for the regulatory period in which the purchase is anticipated. As a consequence, the NSP needs to justify the purchase to the AER in its regulatory proposal.

Such justification typically includes evidence confirming the expected availability and/or cost of later acquisition, and evidence that the strategic purchase is expected to lower the overall cost borne by consumers over time (for example, by comparing the total costs of the investment with and without the strategic acquisition). Where the AER considers that the NSP has demonstrated that the strategic purchase is prudent, it would be approved as part of the regulatory determination process.

3.2.2 Principles for treatment under the RIT-T/ RIT-D

The RIT-T or RIT-D is a separate process which is applied at the later time of the investment decision. At this time the costs of any strategic acquisitions are sunk. However, there are potentially benefits if an option is identified which does not require the land/ easements, and which enables disposal of these assets as a consequence.

At the time the RIT-T/ RIT-D is applied, options (particularly non-network options) may be identified that allow the deferral of eventual network investment. In this case, any land and/or easements that were strategically acquired will continue to eventually be needed (albeit at a later date). As a consequence, there are no benefits or additional costs associated with such options, as the NSP will need to continue to hold the land/ easements to enable later network investment.[18]

There are therefore no costs or benefits which would need to be included in the RIT-T or RIT-D assessment.

However, there may be some options assessed under the RIT-T/ RIT-D which, if selected, would mean that the strategic land/ easements were no longer required. For example, an alternative route for a network option may be identified, or a non-network option may be identified which would avoid or change the nature of the network investment. In this circumstance, the disposal value of the strategic land/ easements should be included as a benefit in the RIT-T/ RIT-D analysis for those options that would result in the land/ easements no longer being required.

Grid Australia notes that the disposal value of strategic acquisitions will differ substantially depending on whether the strategic assets held are land or easements.

3.2.3 Reapplication of the RIT-D where there is a material change in circumstances.

The NER require DNSPs to reapply the RIT-D, where there has been a material change in circumstance.

In the RIT-D Application Guidelines, the AER states that it considers that the requirement to re-apply the RIT-D will only occur on an 'exceptional' basis. Grid Australia supports the AER's view, and considers that it applies equally to circumstances which would justify the reapplication of the RIT-T.

The AER provides the following examples of what it considers would constitute a material change in circumstance, requiring the reapplication of the RIT-D:

- a change in demand forecasts, which means that the preferred option would no longer address the identified need; and
- community opposition following completion of the RIT-D, which requires undergrounding of sections of the original route.

In relation to the second example, Grid Australia cautions against requiring a re-application of the entire regulatory investment test process in circumstances in which a subsequent environmental process imposes additional requirements on the investment. By necessity the RIT-T and RIT-D processes are applied prior to the separate environmental and community consultation processes.

Where a subsequent process imposes additional requirements on the preferred option, it may be sufficient for the NSP to demonstrate that the associated additional costs will not alter the outcome of the regulatory investment test. For example, the original test may already have encompassed sensitivity analysis on a cost increase of

[18] Given that the justification for strategic acquisitions is made in relation to expected future developments (i.e. cost and availability), the deferral of the time at which the land or easements are needed would not be expected to materially change this justification.

that magnitude, or the change imposed (such as undergrounding) may affect all options. Whilst it would be appropriate for the NSP to revaluate whether the outcome of the investment test may change in the light of the new requirement, such an evaluation may be able to be achieved by re-running some of the test modelling, rather than re-doing all of the prior (lengthy) consultation process.