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Dear Chris,

Submission on the Draft Regulatory Investment Test for Distribution ("RIT-D")

EnerNOC appreciates the opportunity to comment further on the RIT-D, including the draft application guidelines ("Draft Guidelines") and the Explanatory Statement accompanying the drafts.

This is an important issue. Unless the RIT-D is designed and implemented well, it will lead to Distribution Network Service Providers ("DNSPs") choosing the wrong investment options, i.e. spending consumers' money in ways that are not in consumers' long-term interests.

However, while it is necessary to get the RIT-D right, it is not sufficient: the RIT-D can only succeed in driving efficient investment choices if it is supported by incentive mechanisms that align DNSPs' interests with consumers'. The proposed RIT-D is far from an objective test – realistically, it could never be – so the proponent's attitudes toward the options does matter. Without this alignment, DNSPs would continue to favour traditional network investments, both because they know them best and because they believe that they will provide them with the highest risk-adjusted return. They would hence treat the RIT-D as merely a compliance exercise.

This submission makes five specific recommendations, which appear in bold below.

1 Demand response payments

EnerNOC welcomes the treatment of demand response payment described in the Explanatory Statement:

> *"If we are to consider changes in voluntary load curtailment, it would be consistent to also consider demand response payments as a market benefit."*[1]

[1] Explanatory Statement, section 2.4.2, p.12

We agree that this is consistent: consumers benefit by receiving payments for providing demand response, and incur costs in providing it. It is the net of these that matters.

The Explanatory Statement makes this clear:

> *"A demand response payment is, **at least partly**, compensating consumers for the cost of not consuming electricity. **To this extent**, benefits that energy consumers receive from dispatch payments would be offset by the negative market benefit of not consuming electricity."*[2]

The key phase here is "at least partly": not all of the payment is needed to cover costs. Hence the benefits to participating consumers are not entirely offset by their costs of participation.

A consumer that provides demand response suffers some opportunity costs and may bear some direct costs. However, these must be less than the payment received by the customer – otherwise there would be no net benefit for the consumer from participation, so the consumer would not choose to provide demand response.

Unfortunately, the current wording of the Draft Guidelines is not consistent with the approach set out in the Explanatory Statement.

Specifically, the Draft Guidelines suggest:

> *"In the case of demand-side options, rewards or inducements paid to consumers for voluntary load curtailment could be counted as either (i) a cost of the demand-side option or (ii) a negative market benefit of the option"*

Option (ii) is incorrect: it makes no sense to treat a payment to a consumer as a negative market benefit. The relevant quantity for any negative market benefit is the cost borne by the consumer in providing voluntary load curtailment.

Option (i) does work, after a fashion: the payments can be treated as costs of the demand-side option. However, these costs are exactly cancelled out by the positive market benefits to participating consumers of receiving those payments. The net effect is that the payments are simply a transfer, which plays no part in the economic cost-benefit analysis.

The only relevant figures are the economic costs borne by consumers in providing voluntary load curtailment. As discussed above, we know that these are definitely smaller than the demand response payments.

Section A.1 in the Draft Guidelines asserts that

> *"in a competitive market, the amount consumers need to be paid to curtail*

2 *Ibid.* (our emphasis)

should reflect the real loss of utility they experience from not consuming power"[3]

and suggests that payments made to consumers for providing demand response

> *"can be used as a representation for the loss in utility to those customers experience and therefore as a negative market benefit of the option."*[4]

As discussed above, we know that the loss of utility suffered by consumers (plus any direct costs they incur in providing load curtailment) cannot be more than the payments they receive: if it were, consumers would not choose to participate.

However, it is not reasonable to expect consumers to provide a service on a pure cost-recovery basis. Such altruism is unusual. In general, they will not do it unless it is worth their while. The threshold for it being worth their while can be quite high: consumers would be quite happy not to participate, and need to be induced to do so.

It was suggested in the AER's RIT-D workshop on 26 June that participating consumers should be considered as equivalent to a transformer manufacturer supplying an NSP with equipment for a network option. There is a crucial difference: whereas the transformer manufacturer wants to provide its products, as part of its core business, so long as they make an acceptable margin, voluntary load curtailment is not any consumer's normal business; rather, it is a distraction that must be made sufficiently rewarding to be attractive.

If an NSP were to reduce off-peak network tariffs to incentivise consumers to move some of their demand to off-peak times, nobody would argue that it necessarily followed that consumers incurred economic costs exactly equal to the reduction in their network charges. However, you could reasonably assume that the economic costs incurred by consumers must be less than their benefits from tariff reductions. This issue is exactly analogous.

The California Public Utilities Commission considered the economic treatment of incentive payments to participating consumers in some detail when drawing up their Demand Response Cost Effectiveness Protocols. They supported the approach set out in the Explanatory Statement and rejected that implied by the Draft Guidelines:

> *"utilities have in the past used incentives paid plus bill reductions minus capital costs as a proxy for measurement for participant costs. However, ... this is not an accurate estimate of participant costs because it assumes that participant benefits are equal to participant costs. Instead, the protocols establish the quantity (incentives + bill reductions – capital costs) as the* ***maximum*** *value for the total of transaction and lost value of service costs... The value calculated*

3 Draft Guidelines, section A.1, p.52

4 *Ibid.*, example 15, p.52

above shall be used as the maximum value for the purpose of the sensitivity analysis, with a lower value used as the standard value for this quantity."[5]

Section 3.N of the Protocols analyses the issues and prescribes the following approach:

"[proponents] should assume that the maximum possible value of the transaction costs and value of service lost can be approximated as the value of all incentives paid to customers plus the customers' total estimated bill reductions minus any participant capital costs. Because this is the maximum value possible for this quantity, sensitivity analysis will be done which reflects lower possible values, as shown in the DR Reporting Template spreadsheet."[6]

The corresponding template spreadsheet[7] estimates participants' costs as 75% of the demand response payments in the "base case", with 50% and 100% used for sensitivity analysis.

To resolve this issue, **we recommend that the AER**:

Recommendation 1

- **Rewrite the relevant sections of the RIT-D Application Guidelines** to make the treatment of payments to participating consumers consistent with the approach indicated in the Explanatory Statement.

Recommendation 2

- **Provide specific guidance** about the proportion of payments to participating consumers that can reasonably be assumed to be economic costs, along the lines of those provided by the California PUC.

2 Option value

We welcome the AER's new, stronger treatment of option value. The following statement in the Draft Guidelines:

"It is important that RIT-D proponents consider all credible options and 'sub-options' so they can adequately take option value into account"[8]

is a significant improvement on previous guidance, and Example 6 demonstrates the required approach quite clearly.

However, we would strongly recommend that the AER redraft the following statement, which also appears in the Draft Guidelines:

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5 CA PUC, *Decision adopting a method for estimating the cost-effectiveness of demand response activities*, Decision 10-12-024 in Rulemaking 07-01-041, 16 Dec 2010, p.39 (emphasis original)

6 CA PUC, *2010 Demand Response Cost Effectiveness Protocols*, p.36, available from http://www.cpuc.ca.gov/PUC/energy/Demand+Response/Cost-Effectiveness.htm

7 Available from the same web page as the Protocols.

8 Draft Guidelines, section 8.1.1, p.32

"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."[9]

This statement is problematic because it does not make clear what "appropriate" identification of credible options entails. It can hence be taken out of context and used as an excuse not to consider option value at all.

Exactly this has happened with a similar statement in the RIT-T Application Guidelines.[10] AEMO, for instance, appears to have boilerplate text to the effect that there is no need to consider option value, as part of its template for all RIT-T reports it prepares.

As far as we are aware, none of the RIT-T publications to date have considered options and sub-options and evolving combinations of options in a way which could capture option value.

Recommendation 3

To avoid this failure recurring with the RIT-D, **we recommend that the AER reword this statement** so that it cannot be taken out of context in this way. For example, it could include a phrase indicating that, for option value to be captured, an adequate number of options must be considered, along with explicit consideration of how different options or combinations of options may later be chosen as new information becomes available.

3 Treatment of uncertainty

Every input to a RIT-D assessment is uncertain. Appropriate treatment of this uncertainty should be at the heart of the RIT-D process.

Recommendation 4

It is easy to be overconfident about estimates and forecasts – to imagine that the future is much more certain than it really is. To mitigate this, **we recommend that the AER include guidance that historical errors in similar estimates and forecasts should be taken into account when choosing scenarios and sensitivity tests**. For example:

- If an assessment depends on a 5-year zonal demand forecast, and previous 5-year zonal demand forecasts have turned out to have errors of up to -20% and +10%, then scenarios should be included with offsets of at least -20% and +10% from the main forecast.
- If a previous similar construction project has had a 20% cost overrun from its initial estimate, then cost overruns of at least 20% should be included as a sensitivity test.

9 *Ibid.*, section A.6, p.59

10 AER, *Final RIT-T Application Guidelines*, section 3.6, p.39

- If an option is expected to take 3 years to build, and a previous construction project of similar expected duration was completed 6 months late, then a scenario should be included in which the option is delivered 6 months later than planned.

The costs of non-network options are also subject to uncertainty: both generation and load curtailment options have variable costs which depend on how often they are dispatched, which is uncertain.

Recommendation 5

Network support contracts generally include a maximum number of hours for which the resource can be dispatched, chosen such that it will suffice even in extreme years. We understand that some NSPs have historically assumed that non-network options will be dispatched for this maximum number of hours. This tends to overestimate the cost of the option, sometimes significantly. **We recommend that the AER clarify that the expected, rather than maximum, number of hours of dispatch should be used when estimating the variable costs of non-network options.** This expectation could be calculated by examining the probability distribution of operating conditions. However, it would probably suffice to use appropriate forecasts. For example, whereas a non-network option may be designed to meet a 10% probability of exceedance (POE) demand forecast, a 50% POE demand forecast would give a better indication of expected dispatch hours.

I would be very happy to provide further information or clarification, if it would be helpful.

Yours sincerely,

Dr Paul Troughton
Director of Regulatory Affairs