27 November 2016

Submissions
WAG Chair
c/- Electricity Authority
PO Box 10041
WELLINGTON

via email: wag@ea.govt.nz

Dear WAG members

Instantaneous Reserve Event Charge and Cost Allocation Discussion Paper

Thank you for the opportunity to provide comment on the above Discussion Paper.

Please find below our response to specific questions raised in this paper.

If you would like to discuss our response further please do not hesitate to contact me.

Yours sincerely

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Q.1. Do you agree with our identification of the problems with current arrangements?

Yes.

Our view is that although the current island allocation is sufficient in the interim, a more accurate allocation option is required longer term.

We agree with the WAG that the event charge should not be retained (see our response to Q17 for more detail).

Q.2. Do you agree with these basic principles for allocating IR costs?

Yes, but the intention of sending a marginal price signal should also take into account the benefits to the end consumer which is one of the EA's key objectives. Please see our response to Q9 for more details.

Q.3. Do you agree that continuing with island-based cost allocation after the introduction of the NMIR is unlikely to create perverse incentives on parties to inefficiently withhold energy or IR capacity?

Agree, but as mentioned in 1), this should be an interim solution only.

Q.4. What are your views on the merits of moving to a runway methodology (or its sub-options)?

Contact agrees with the WAG's findings that moving to a runway methodology would:

1. Have a modest net benefit – Contact believes the unintended consequences could actually result in a net cost for the market.
2. Have an unintended consequence – Contact agrees that an unintended consequence of allocating more cost to plant that is already marginally economic may lead to plant being retired earlier than would otherwise be expected. The subsequent risk of scarcity may come as a net cost for the market.
3. Affect regulatory certainty – Contact agrees that regulatory certainty is important for a healthy competitive market to operate efficiently.

It is mentioned in the paper that the runway approach may also influence the placement of renewable investments based on the level of HVDC transfer, hence the amount of risk and costs. Our view is that the location of this type of plant is driven by the location of the energy source and the economics of this would outweigh the IR procurement costs.

Based on the above, Contact does not view there is enough merit to move to a runway methodology.

Q.5. Do you agree that a de minimis should continue and, if so, at what level?

Yes, but that task would lie with the System Operator to determine an appropriate de minimis level if it were to be reviewed.

Q.6. Are there other cost allocation options that you think should be considered?

Yes.

Our view is that another option would be a variation to option 5, where the HVDC risk is allocated nationally as the HVDC assets are a common good that provide a benefit to all market participants and the end consumer.

Q.7. Which option do you think sends price signals to underlying causers of the need for, and location of, IR to be procured in a manner which best meets the cost allocation principles of section 5?

Option 3 is Contact's preferred solution. This option is relatively simple to understand, would have a low cost to implement, and allocates cost in a fair manner, i.e. to the extent that reserves can be procured nationally, the costs are allocated nationally. To the extent that reserves need to be procured in an island, the costs are allocated to that island.

Option 5 could be considered in the future when variations to the TPM see the allocation of HVDC charges move to a beneficiary pays approach. In its current form we do not believe it is efficient for South Island generators to pay the full IR cost of the HVDC when the value of the HVDC asset is realised nationally. As mentioned in Q.6, if Option 5 was to be considered immediately, HVDC IR costs would need to be allocated nationally.

In regards to the use of AUFLS to cover the NI DC CE risk such as the HVDC in the event of Tiwai closure, Contact would be supportive of seeing this investigated further.

Q.8. Do you think the choice of general cost allocation approach (i.e. pro-rata versus runway) has a bearing on which option for cost allocation under the NMIR would be most appropriate?

No. We believe the choice of general cost allocation and the cost allocation under NMIR should stand on their own merit.

As per our response to Q.4, we agree with the WAG that there is not enough to merit moving from the existing general cost allocation to the runway method.

Q.9. To what extent do you think the choice of best option is affected by the effectiveness of how costs allocated to the HVDC are passed-on to 'underlying causers' of the level of energy transfer across the HVDC?

A large extent.

As per our response to Q6, the HVDC assets are a common good and provide benefit to all market participants i.e. supplies North Island demand at times of scarcity in that island and enables cheaper renewable energy on an ongoing basis which is a benefit to the end consumer. A marginal price signal to withhold this generation due to IR allocation would have a similar effect to that of the HAMI where generation is withheld due to the HVDC charge and would not be the most efficient outcome.

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Q.10. Do you believe that some IR cost allocation options could materially impact on participants' incentives to offer energy and IR to a degree that could have material outcomes on these markets?

Yes.

Q.11. If yes, which options are likely to give rise to such outcomes, and could you provide worked examples demonstrating such effects?

As per the submission by Meridian Energy, it was highlighted that option 2 would create inefficient market outcomes once NMIR is no longer active (NI DC CE is the binding risk).

Q.12. Do you agree that HVDC-related IR costs should continue to be allocated to the HVDC owner and passed-on to market participants via the TPM, and do you have any observations about the interim allocation of IR costs under the NMIR?

No, not without the TPM moving to a beneficiary pays approach for the allocation of HVDC costs. As per our response to Q9, the HVDC asset is a common good and provides a benefit to all market participants, but under the current TPM the HVDC charge (which includes the IR charge) is passed through to South Island generators. There is a requirement to either a change to the current TPM, or as per our Q6 response, allocate HVDC IR costs on a national basis.

We do not envisage any issues with the interim allocation of IR costs**.**

Q.13. Do you think cost-allocation for commissioning plant should: a) continue as is; b) change to be quantity-and-price-runway-based without application of a de minimis; or c) change to be quantity-runway-based without application of a de minimis?

Our view is that C is the preferred option.

At present there is no incentive on commissioning plant to have an efficient commissioning process in place to minimise the period that the plant is unproven on the system as the additional IR costs are socialised.

Q.14. Do you think a change to allocating costs to commissioning plant on a runway basis should only occur if general cost allocation were to move to a runway basis?

No.

Commissioning plant is an additional temporary risk and at present, a cost that other participants should not bear. Therefore the decision on the cost allocation method for commissioning plant should be separated from that of general cost allocation.

Q.15. What cost-allocation approach do you think should apply for plant with under-frequency and voltage-fault-ride-through dispensations?

Retain the current cost allocation method for existing plant as these assets were designed and commissioned under the current code (or previous versions of) requirements.

Q.16. What measures do you think should be implemented to address small generation plant that are currently excluded from the need to comply with frequency-related AOPOs?

The code currently has provisions to manage this issue by the EA invoking clause 8.38.

Q.17. Do you think the event charge should be retained, and if so, on what basis?

No.

The charge does not incentivise reliability of plant as there are commercial and compliance drivers that would take precedence as mentioned in the discussion paper i.e. loss of revenue and increase in costs (both directly and indirectly), and capacity limits imposed by the system operator. If this was an incentive then we would not expect to see any large generator trippings due to the significant UFE charge. These events are due to unforeseen circumstances.

Generators already pay reserve procurement costs, so effectively there is a double charge for these costs with the event charge. The fact that the causer is rebated some of this charge due to its allocation (likely to be significant as a sizeable amount of generation is required to cause an event) highlights the shortcomings with this charging regime.

In the past there has been issues relating to a Transpower asset tripping causing a generator tripping that causes an UFE. This type of event results in the issue of apportioning the cost to the “causer”. In many cases it is unclear who the causer is and often the charge apportionment is settled outside the requirements of the code, or a lengthy legal process takes place.

We do not support the proposal that IL providers should be included in the current rebate allocation for event charges. IL providers bear no pre event costs (operating costs + allocation costs). We do not see a risk of IL participation in the market being threatened as there has been a significant reduction in NI generation capacity recently, and under a TWI reduction or retirement of large unit scenario and the planned AUTC modelling, the requirement for IL would increase to manage the NI DC CE risk.