Wholesale Advisory Group

Instantaneous Reserve and Event Charge Cost Allocation - WAG Discussion Paper

Summary of submissions

14 December 2016

1 The WAG published a discussion paper and sought feedback

The WAG is undertaking a 'first principles' review of the approach to allocating instantaneous reserve costs, and the event charge regime (IRECCA). Its aim has been to determine if the existing arrangements are consistent with the Authority's statutory objective.

The WAG published a discussion paper on 11 October 2016 and sought stakeholder feedback to aid its consideration. In preparing the discussion paper, the WAG came to a view on some issues, but was not at the point of proposing changes to the existing arrangements.

The discussion paper:

- described the current IR procurement and cost allocation arrangements
- identified aspects of the current arrangements that may be resulting in inefficiencies
- set out a framework for considering the merits of IR cost allocation
- proposed two high level principles for allocating IR costs
- discussed how 'principled' the current approach is in the context of:
  - the general approach to allocating costs
  - HVDC-related issues
  - allocating additional costs arising from secondary risks
- set out five potential cost allocation options (illustrated in Appendix A below):
  Option 1: island-based allocation (status quo)
  Option 2: national allocation
  Option 3: factored by HVDC reserve sharing limits
  Option 4: cost-to-island-causers
  Option 5: cost-to-HVDC-then-to-AC-island-causers
- reviewed the event charge regime.

The discussion paper was prepared prior to the introduction of a national market for instantaneous reserves in October 2016.

2 The WAG received 11 submissions on its discussion paper

The submission period closed on 28 November 2016 (having been extended from the original 22 November 2016 deadline due to earthquake interruptions for some submitters). The WAG received 11 submissions:

• Contact	• Mercury	• Pioneer
• EnerNOC	• Meridian	• Transpower
• Genesis	• Nova	• Trustpower
• MEUG	• NZX	

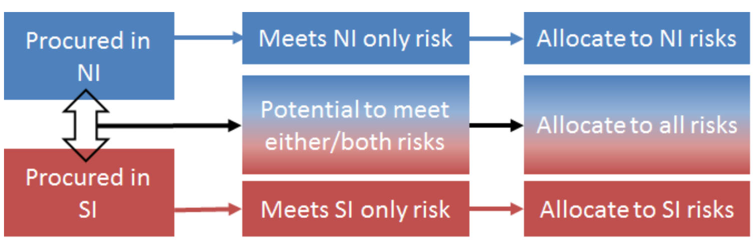
This paper includes a tabular summary of submitters' responses structured around the questions WAG posed in its discussion paper (Appendix B below). The WAG discussion paper and full set of submissions are available at http://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/review-of-ir-event-charge-and-cost-allocation/consultation/#c16198.

Appendix A. The five options WAG considered in its IRECCA discussion paper (11 October 2016)

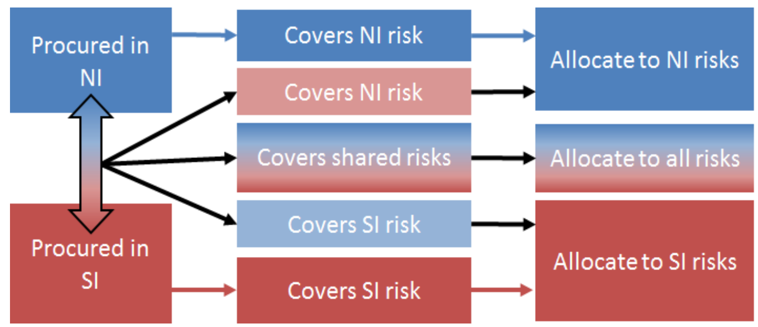
1. Island-based *(status quo)*

2. National

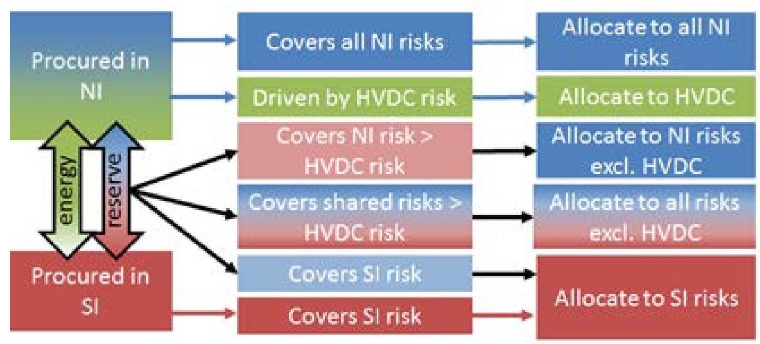
3. Factored by HVDC IR sharing limits



4. Cost-to-island-causer



5. Cost-to-HVDC-then-island-causer



Appendix B. WAG's IRECCA Discussion Paper (11 October 2016) – summary of submissions received

Q1: Do you agree with our identification of the problems with current arrangements?	
Submitter	**Submitter's comment**
Contact	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).
EnerNOC	In general. The term sheet being developed for the WAG meeting#42 is better.
Genesis	Yes, however in regards to the question "what aspects of the IR cost allocation arrangements may be resulting in inefficiencies?" - the question suggests treating reserves in isolation. Gaining efficiencies in IR cost allocation but incurring (potentially greater) inefficiencies in the energy market will be missing the mark of achieving the Authority's statutory objective - competition in, and reliable supply by, the efficient operation of the electricity industry for the long-term benefit of consumers. *[from cover letter]* Whilst we appreciate the impact of any proposed changes to the IR regime will be difficult to predict, we believe consideration of changes to the IR regime in isolation, without carefully considering the cost to efficiency in other markets, will not promote efficient operation of the electricity market for the long term benefit of consumers. We do not support the pursuit of efficiency gains in the IR regime where these efficiency gains will not be realised in a net reduction in the energy price. The impact on the end consumer must remain a key consideration for any proposed change/s.
Mercury	Yes. However, the most important issue to resolve is national cost allocation, followed by giving consideration to achieving an appropriately "sharp" price signal to the causers of the need for IR. We feel that event charge issues are of lesser importance as under-frequency events are relatively rare, and increasingly so. There have been 26 such events since 2011, and only 1 event since December 2014. This could be due to the market shifting away from operating large CCGTs as well as the commissioning of a new HVDC pole and control system.
Meridian	As noted [in the covering letter] we consider that the WAG has failed to recognise that the current unit-based

Q1: Do you agree with our identification of the problems with current arrangements?	
Submitter	**Submitter's comment**
	allocation methodology is a significant problem that needs to be addressed as a first priority. If 'causer pays' is the key principle to be observed (and Meridian agrees it is) a methodology that so clearly fails to accurately align and reflect costs back to their causers is unsatisfactory. In particular, a station with seven units of 120MW drives the same level of reserve cost as a station with a single unit 120MW station and far less reserve cost than a station with a 400 MW unit. Allocating 7 x 120MW of reserve costs to the first station giving it a cost allocation which exceeds the costs allocated to the 400MW station, represents a fundamental flaw in the current methodology. Otherwise, subject to the points noted below, we broadly agree with the WAG's identification of problems. Also while not a focus of the WAG's assessment, interactions with revenue arrangements are also an important consideration. These interactions are not a 'problem' under the current cost allocation methodology but potentially will be if another methodology is chosen. In particular, care needs to be taken with cost allocations that disrupt the alignment of charges with prices as they carry with them the possibility of higher prices overall, compromising in the process the benefits intended to be achieved (i.e. lower cost reserves overall). The five specific problems with the current IR cost allocation arrangements identified by the WAG are: 1. A likely 'dulling' of price signals for causers of IR (such as large unit plant) from the current pro-rata general cost allocation method which, in the view of the WAG, may result in long-term inefficiencies in plant investment. 2. HVDC related distortions in price signals from the continuation of an island-based cost allocation approach, with potential resulting short-term operational and / or long-term investment inefficiencies. 3. HVDC related potential dulling of price signals from using the Transmission Pricing Methodology (TPM) to pass through HVDC IR costs which may cause long-term inefficiencies in plant investment. 4. Inconsistencies in the allocation of IR costs to assets presenting secondary event risks (e.g. commissioning and AOPO non-compliant plant) which may result in long-term investment inefficiencies and some operational inefficiencies. 5. Event charges provide limited impact on incentives for reliability and do not allow reimbursement for actual interruption costs in the way originally intended. In respect of (2), it seems from a review of the WAG's paper that the WAG considers that this potential problem is more theoretical than real – see the discussion in Meridian's response to Q6 below. Meridian agrees. In addition, as already mentioned rather than just considering distortion of price signals from cost allocation alone, what should be the focus is the overall effect of cost allocation as it interacts with revenue arrangements i.e. also considering how island-based pricing can act to subdue prices irrespective of whether receiving island prices are higher.

Q1: Do you agree with our identification of the problems with current arrangements?	
Submitter	**Submitter's comment**
	As our Q9, and Q13-Q17 responses discuss in more detail, Meridian's initial comments on the other problems identified are that: • The allocation of IR charges to the HVDC and subsequent pass through using the TPM does not create any meaningful incentives for reliability and does not achieve causer pays. It may well be that there are no better alternatives, but the issue should be considered further. Regardless, it is not until 1 April 2019 at the earliest that the TPM could move from the lowest rung of the EA's hierarchy of cost allocation approaches and become a 'beneficiaries pay' approach. Before that time Meridian does not consider that the WAG's Option 5 'Cost-to-HVDC-then-to-island-causers' to be a credible alternative to the current arrangements. • Commissioning plant 'causers' of secondary event risks have potential to create high IR costs and should be charged using a cost effective method of allocation. In terms of the other categories of secondary risk causers identified by the WAG, we agree with the principle that IR costs should be recovered from causers where it is cost effective to do so. We agree with the WAG's view that this criteria is unlikely to be met for smaller plant (< 30 MW), and support more extensive adoption of AOPO standards instead being pursued in the first instance. The event charge is more in keeping with a causer-pays approach and should be retained, with the level at which the charge is set to be reviewed. Meridian does not support re-allocating the event charge to IL providers under existing procurement arrangements.
MEUG	Yes.
Nova	Yes.
NZX	NZX agrees with the WAG's assessment of the issues with the current Instantaneous reserve cost allocation methodology.
Pioneer	Pioneer agrees it is timely to review the current arrangements for charging for under-frequency events and allocating the costs of procuring instantaneous reserves. We also recommend a cautious approach to any change at this time noting that: • the new National Market for Instantaneous Reserves has only been operational for one month, • the Transmission Pricing Methodology is unresolved and may or may not represent an efficient mechanism to pass-through IR costs, and

Q1: Do you agree with our identification of the problems with current arrangements?	
Submitter	**Submitter's comment**
	• the estimate of costs and benefits of making any changes must be robust and the benefits realisable / not uncertain.
Transpower	Yes.
Trustpower	Yes.

Q2: Do you agree with these basic principles for allocating IR costs?	
Submitter	**Submitter's comment**
Contact	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.
EnerNOC	Yes.
Genesis	Agree.
Mercury	Yes.
Meridian	Meridian agrees with the WAG's suggested principles, namely causer-pays based charging and signalling of marginal costs, to ensure plant and system costs are correctly signalled and internalised. Achieving this will require cost allocations that reflect the risks posed to the system by the generating units to which the relevant costs are allocated. As the WAG notes it is also important to take account of potential limitations set by the practical realities of the sector. A third, additional principle or test of the outcomes produced by applying the first two principles should also be considered: • Principle 3 – Cost allocation arrangements need to be non-distortionary and promote efficient market outcomes. This objective / test needs to be applied broadly – specifically in relation to ensuring appropriate energy and reserves market incentives are maintained and in respect of ensuring that appropriate utilisation of increased HVDC capacity is not inhibited.
MEUG	Yes MEUG agrees with the 2 principles: 1. Costs would be allocated to parties causing the need for IR; and 2. The cost allocation would send a marginal signal.
Nova	Yes.
NZX	NZX agrees that the process of assigning IR cost on a 'exacerbators pay' principle should be applied where possible.
Pioneer	Pioneer agrees with the WAG conclusion – that system stability is a common good and therefore it is not considered

Q2: Do you agree with these basic principles for allocating IR costs?	
Submitter	**Submitter's comment**
	practicable to develop market-based mechanisms for cost allocation.
Transpower	We support causer pays as the underlying principle and the current, negotiated, pro-rata approach as preferable under the DME framework.
Trustpower	Yes.

Q3: 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?	
Submitter	**Submitter's comment**
Contact	Agree, but as mentioned in 1), this should be an interim solution only.
EnerNOC	Yes.
Genesis	Agree. However, the end goal of NMIR should be a well-functioning and efficient national reserves market that delivers a better (least overall cost) outcome for the consumer. We believe there should be greater urgency to move towards a cost allocation regime that is fair and straightforward in a timely manner, rather than continue with island-based cost allocation just because it creates no perverse outcome.
Mercury	Transitioning from island-based cost allocation to national cost allocation is crucial to a well-functioning national reserves market which incentivises participants in both islands to efficiently offer and compete for reserves. Island-based cost allocation discourages "forward reserve sharing" from one island to another by parties who are also reserve payers. This is because any additional reserve procured for export to another island increases the reserve procured in the exporting island. Many participants cleared for reserve in the exporting island could now face increased reserve availability costs under island-based allocation, even if their percentage share of reserve costs in the island is unchanged. A national cost allocation will create the opportunity for a kind of "gearing effect" whereby a participant could offer and be cleared for more reserve to be exported to another island whilst its reserve costs go down since the reserve procured in the exporting island will be partially paid for by payers in the receiving island. This will encourage competition in the national reserves market. By the same token, under national cost allocation, beneficiaries of inter-island reserve sharing (i.e. causers of the need for reserves) will be required to contribute towards the costs of such reserve imported into their island. In short, the benchmark should be whether or not we have a well-functioning national reserves market rather than being content with the fact that island-based cost allocation is unlikely to create issues relating to "perverse incentives" that could render national procurement less efficient than island-based procurement. This is an unsatisfactorily low standard to aim for. Furthermore, as the national market has only just commenced operation it is too early to make an informed assessment about perverse incentives.

Meridian	Yes. Maintaining island-based cost allocations post the introduction of the NMIR carries considerably lower risk from an incentives perspective than the method of national cost allocation originally contemplated by the Authority (national allocations at all times the HVDC is operational, with no adjustment to reflect the level of IR sharing). The originally contemplated approach would have exposed participants to high costs they are prevented from managing using additional reserves (owing to reserve sharing capacity constraints). This had the potential for wider flow-on energy market implications such as the inefficient withholding of capacity.1 Meridian's view that continuing with island-based allocations is unlikely to create perverse incentives has been borne out by our monitoring to date of use of island-based cost allocations for the NMIR. Continuing with the current island-based cost allocation approach remains an acceptable and valid approach pending the identification of a clearly "better" alternative.
MEUG	We would like to observe market behaviour with NMIR in various situations before being able to comment.
Nova	Yes.
NZX	Creating perverse incentives from these changes is unlikely as we agree with the WAGs assessment that "it is generally the case that the loss of energy revenue will outweigh any gain in terms of reduced IR cost allocation."
Pioneer	We 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
Transpower	Probably only in the short term.
Trustpower	Yes.

[1] Meridian's '*Proposal to alter the way IR availability costs are allocated*' 26 April 2016 submission provides further details (http://www.ea.govt.nz/dmsdocument/20699)

Q4: What are your views on the merits of moving to a runway methodology (or its sub-options)?	
Submitter	**Submitter's comment**
Contact	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.
EnerNOC	Only if the annual benefit is shown to be larger and can justify such a change.
Genesis	We do not agree moving to a runway methodology or its sub-option will be viable. Moving to a run-way method for existing plants will result in the largest thermal unit(s) being offered at lower levels at the times of highest reserves (and energy) prices. Out of the various options, the grand-father approach will at least address this concern. However, we feel this point raised is not related to achieving a solution for National Allocation of Reserves, rather a fundamental reserve market design question.
Mercury	We agree with the WAG analysis that there are insufficient tangible benefits and too much uncertainty to justify moving to a runway methodology or any of its sub-options. We also agree that there is the high impact, low probability potential for uneconomic early retirement of large plant as a consequence of implementing a runway methodology. Grandfathering would introduce additional complexity into the administration of reserve cost allocation and the operation of the reserve market. Phasing in a runway methodology would be unlikely to improve the aforementioned uncertainty over the costs and benefits; it would merely delay them somewhat.

	Mercury is not convinced that it is necessarily a perverse outcome that a station comprised of a large number of medium sized units has a larger IR cost footprint than a station comprised of a single large unit. The principle behind reserve cost allocation is to allocate costs to causers of the need for IR. These causers are units larger than the de minimis figure in the Code. This is somewhat logical because the more large units that exist on the transmission system, the more likely there will be trip events requiring the deployment of reserves. This then appropriately sends a reserve cost price signal to those operating and investing in larger generating units. We also do not see how seven medium sized units at one location should be treated any differently in terms of reserve cost allocation to a participant operating a handful of medium sized units spread across an island. There appears to be no suggestion from any quarter that the latter is inequitable, whilst the former appears an unfair situation to address simply because there are multiple units in one place.
Meridian	Meridian considers that the choice between a runway methodology and a pro rata allocation method is a secondary issue to the fundamental problem with general cost allocation namely the current unit-based approach, as opposed to allocating charges to a station in accordance with the actual risk amount or reserve requirement driven by that station. That said, when it comes to choosing between pro rata and runway we accept the potential benefits of a runway methodology are uncertain, but also consider the potential benefits are understated by the WAG's analysis. In particular: • If the fundamental problem of unit-based allocation is not addressed, then as the WAG recognises in the paper, the runway methodology will potentially ameliorate the perverse result produced by national cost allocation whereby a medium-sized unit owner could end up paying significantly more in reserve costs than the large unit owner whose investment decisions have driven most of those reserves costs. These costs could be of a scale significant enough to encourage inefficient operational decisions – whether in terms of withholding capacity or operating at reduced capacity. • The assessment of investment efficiency impacts is premised on current and future investment projects alike being constructed with small generation unit sizes. This is in contrast to some of the more recent investments that have been made – in particular the recent 700 MW HVDC investment and CE risk. • While not a focus of the WAG's assessment, removal of the event charge will further lessen the degree of marginal cost signalling from a pro rata approach. There needs to be further consideration of this impact if event charge removal (which Meridian does not support) is to be progressed. A runway methodology will potentially provide an important corrective measure to the perverse outcomes a national cost allocation may otherwise create (that is, charges that are highly disproportionate to the level of risks created). As an aside, Meridian does not agree with the view of some WAG members (page 28) that the supposed impact on 'regulatory certainty' of moving to a runway approach is a valid consideration. At base this is a form of 'status quo

	bias'. Meridian's view is that: • As the Electricity Authority has recognised elsewhere, 'regulatory certainty' is not promoted by retaining regulatory settings that are clearly inefficient and therefore inconsistent with Authority's statutory objective. Instead, where a better alternative is available "…the Authority consistently and transparently pursuing its statutory objective is the best way for it to promote regulatory certainty and the right climate for investment in the capital intensive electricity industry over the long-term." In Meridian's view the WAG should frame its recommendations accordingly. • If there is sufficient certainty that material efficiency gains are available then regulatory settings should be adjusted to capture those gains.
MEUG	Changing to a runway methodology is conceptually superior. The question should be how and when to adopt a runway methodology. We do not subscribe to a view no change is needed because it's expected no new large generation plant will be built in the future. The market design should be agnostic as to what might happen because markets are unpredictable and we should not rule out new large scale generation plant being built. MEUG has no view at this stage whether an overnight change to a runway method or a transition would be best.
Nova	Nova acknowledges the reservations that the WAG has on introducing the runway approach for general cost allocation; but believes that the principle is important enough such that it should be introduced. That said, the direct impact on the existing large CCGTs should be ameliorated to the extent that owners of the remaining CCGTs are not penalised excessively by a change in the rules, and the issue that NZ no longer needs all three base-load CCGTs operating. As per our cover letter [copied in below], this can be achieved by introducing the runway approach to charging, but at the same time capping the marginal rate applying to the CCGT's as if three large units where still available. By applying such a cap, there will be some unrecovered costs that should be picked up across the rest of the generators. By applying the runway approach in this way, there are still appropriate economic signals for future long-run plant investment and divestment decisions. *[from cover letter]* Nova Energy favours the economic rationale of the 'runway' method of cost allocation. The runway methodology is particularly appropriate in the context of a dynamic environment where users can enter and leave the market and make choices in respect of which resources they employ in doing so, e.g. trading off the economic benefits of utilising larger planes versus higher runway fees and choices of routes. The electricity market, is less flexible in the sense that the 'exacerbators' are locked-in to their investment in power stations, and more flexible in that the 'runway' does not involve a large fixed capital investment. Market participants cannot practically redeploy their investment in power stations to alternative markets. This is most significant in respect of the investment in the remaining CCGTs. Nova therefore proposes that the 'runway' method of cost allocation be

	employed, but subject to a cap on the maximum marginal cost per plant. This would reasonably be at the level that would apply as if each of e3p, TCC, and Otahuhu B power stations were operating at the same level of output. This would still provide appropriate economic signals, but would offset the punitive impact of a new cost allocative methodology on the two remaining CCGTs.
NZX	The runway method does appear to send clearer price signals than the current pro-rata approach. Although there is a large degree of uncertainty around the benefits estimate, because the costs to implement are likely to be significantly less the change appears to be worth pursuing. As participants already operate under a certain degree of regulatory uncertainty it is unlikely that changing the IR methodology would have a material impact on the industry's perception of regulatory certainty. If uneconomic retiring of units is a concern, one option may be to grandfather in larger plants such as Huntly – e3p and TCC. It appears that these units will be the ones most affected by a change and therefore a gradual change in IR costs may be preferable.
Pioneer	We also agree that it is not appropriate to move to a runway approach for general cost allocation. We particularly support the WAG's focus on the impact of change on investor certainty and the use of the Principle 4 of the Code Amendment Charter – Preference for Small-Scale 'Trial and Error' Options
Transpower	Agree with WAG conclusion to not recommend a change (back) to the runway approach.
Trustpower	We agree with the WAG provisional view (p28), that the current pro-rata method is preferred as least risk given the modest and uncertain relative benefit of a runway approach.

Q5: Do you agree that a de minimis should continue and, if so, at what level?	
Submitter	**Submitter's comment**
Contact	Yes, but that task would lie with the System Operator to determine an appropriate de minimis level if it were to be reviewed.
EnerNOC	A de minimis approach is needed. The level should be determined by changes to the risks on the system.
Genesis	If we are to move to a run-way method, the de minimis should be reduced (0MW). If not, the causers will be doubly penalised. On top of getting its 'fair' share of IR costs, the smaller generators are also completely exempted.
Mercury	We agree that the 60 MW de minimis is generally appropriate. There is likely some merit in the System Operator investigating whether the 60 MW figure is still appropriate as the threshold below which IR would not be required. However there are likely to be other priorities the System Operator would be better served attending to first.
Meridian	Meridian, like the WAG, considers there could be merit in the SO reviewing whether the 60 MW de minimis threshold remains appropriate. This threshold has been in place for almost 20 years without adjustment and was decided on with only minimal analysis at that time.
MEUG	As we prefer a runway methodology then there would, with that approach, be no de minimus. If the pro-rata allocation is retained deciding the optimal de minimus is at best complicated and at worse arbitrary. Another reason why the runway methodology is conceptually superior to the status quo.
Nova	The de-minimis should remain at 60MW as smaller generation plants do not create a significant additional market risk, i.e. unit trips at this level are largely covered by the free reserves, and never set the level of reserves required for a contingent event. The same applies under both the pro-rata or runway cost allocation method. Under the runway cost allocation approach the size of the de-minimis is however less significant, as generators less than 60MW pick up a smaller share of the overall charge. Nevertheless, a de-minimis of 60MW would still be appropriate from an equity and practical perspective given the number of additional units it would need to include.
NZX	If the current pro-rata system was to remain we suggest that the de minimis is reviewed by the System Operator to confirm that below the level of the threshold units will not contribute materially to the need for IR. If the IR methodology was to change to the runway method the de minimis would not appear to be needed.

Pioneer	Pioneer supports the continued use of a de-minimus of 60MW. Figure 8 shows there are 30 generating units above this de-minimus, plus the HVDC. If a unit is of a size when it is not going to create the need for IR – that is, it is not going to create the risk of an under-frequency event or be the largest contingent risk – then the exacerbator pays approach would imply these units should not be required to provide / pay for IR. Also the lowest share of potential IR costs is modelled at 3% in Figure 9 under the status quo – it is not clear from the paper if the benefits of allocating IR costs to units below 60MW exceed the costs.
Transpower	It depends if the grounds for the current approach still hold.
Trustpower	Yes, and we consider that there is no compelling reason (in terms of likely net benefits and costs) to change the level of the de minimus from 60 MW.

Q6: Are there other cost allocation options that you think should be considered?	
Submitter	**Submitter's comment**
Contact	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.
EnerNOC	No.
Genesis	No.
Mercury	No.
Meridian	Yes. As already indicated Meridian believes the first priority in any IR cost allocation review should be to change the current unit-based allocation arrangements and instead allocate costs to a station in accordance with the risk amount or reserve requirement actually driven by that station.2 This is a fundamental problem with the current methodology which is not addressed by any of the options discussed in the WAG paper. Our comments below on the WAG options should be seen in that light. Meridian also considers that, in the context of a 'causers pay' approach allocation of costs to the HVDC and recovery of those costs through the TPM is problematic. All of the options in the WAG paper involve significant allocation of costs to the HVDC and recovery of those costs from the parties who meet the costs of the HVDC under the TPM. The current TPM sits at the lowest rung of the EA's hierarchy of preferred cost allocation approaches. Even if the EA's currently proposed reforms are made (1 April 2019 at the earliest) the TPM will be a 'beneficiaries pay' methodology not a 'causers pay' methodology. Having such a methodology sit at the heart of 'causers pay' approach to IR cost allocation is a fundamental inconsistency. We suggest that other cost allocation options should be considered that have the potential to resolve this inconsistency (e.g. by allocating costs that would have been allocated to the HVDC nationally amongst all generators). **Comments regarding the WAG's options** The WAG paper records that in deciding to defer making changes to IR cost allocation until the WAG had completed

[2] With Manapouri, for instance, its current allocation based on 420 MW of IR costs (7 units *60 MW) = 420 MW) would fall under this approach to an allocation based on the actual reserve costs driven by the station of 60 MW.

	its review the Authority Board considered that "continuing with an island approach to cost allocation was unlikely to be the best long-term solution" (page 35). The reasoning of the Authority's Board is not set out in the WAG's paper. However they seem to have reached this view on the basis that if, for example, North Island generators face only the costs of IR procured in the North Island in circumstances where, in order to meet a North Island risk, an equivalent amount of IR also has to be procured in the South Island (with those costs met by South Island generators) this could: • Affect long term investment and retirement decisions; and • Alter participants' energy and IR offers in a negative manner. The second of these concerns appears to have been dismissed by the Authority Board itself in deciding to persist with island-based cost allocation pending the outcome of the WAG review (and the WAG itself agrees and takes the view that any operational inefficiencies of persisting with the current island-based cost allocation method are largely prevented by the SPD tool – see page 25). Meridian agrees. Experience to date with the NIRM suggests the Authority Board, the WAG and Meridian are correct. In relation to the first concern relating to long term investment and retirement decisions the WAG paper suggests that although in theory the current cost allocation method: • May drive investment in plant of a larger size than is efficient, the WAG are sceptical that this will happen in practice because all the likely (geothermal and wind) new plant that will be built in New Zealand is much smaller than the CCGTs) – see page 26 of the WAG's paper; • May prevent the efficient early retirement of existing plant, in practice this is highly uncertain due to a range of factors – see page 27 and Appendix B. It is therefore not clear why the Authority Board considered that an island approach is "unlikely" to be the best long-term solution. It may be that the Authority Board considers the potential for investment in larger plant (than is efficient) is more significant than the WAG. Alternatively, perhaps the Board considered that the so-called national IR market "automatically" or "by definition" is likely to require a national method of cost allocation. Meridian considers this view is not correct. The analysis to date does not seem to have produced any clear cut reason why an island-based method of allocation and national IR market cannot co-exist, whether on an interim or longer-term basis. As the WAG's paper acknowledges, constraints of the HVDC and technical rules of procurement mean that the IR market cannot function as a national market at all times. In particular, as noted on pages 37 and 38 of the WAG paper: • "…the physical limitations of the HVDC to transfer IR mean that the new NMIR will never be completely 'national' i.e. there will almost always be situations where some relatively expensive reserve needs to be procured in a particular island (generally the North Island because that is where the large thermal units are located) because there are technical limitations on the amount of IR the HVDC is capable of transferring from one island to the other."

- "A DC CE risk can only be met by IR procured in the receiving island. This has significant implications for the NMIR because at high levels of energy transfer across the HVDC, IR must be procured in the receiving island, irrespective of whether it is cheaper in the other island.

At this stage Meridian believes that there is no reason why an island-based method cannot be retained, whether on an interim or longer-term basis at least until there is some confidence that a better alternative has been clearly identified. In the meantime maintaining the current island-based approach remains a legitimate choice and, as recognised by the WAG, it has the "happy coincidence" that it masks the problems with unit-based allocation because the profile of risk setters in each island currently happens to be the same – see WAG paper at page 30.

In respect of options 2 and 3 in the WAG paper Meridian agrees (at least under the current unit-based cost allocation) agrees with the WAG's assessment that:

- Option 2 - a fully nationalised approach to cost allocation (i.e. allocating all costs across risk setters across both islands, with no adjustment for reserve sharing capability) will be ineffective in targeting exacerbators. As we've previously submitted, it is also an unprincipled method with the potential to create wider energy market distortions.
- Option 3 - modifying the fully nationalised method of allocation to account for reserve sharing limits (the "factored by HVDC reserve sharing limits" option) will still mean costs will be imperfectly signalled and causers are not charged in proportion to the level of risk they create. Also, as far as we can tell, this option seems to allocate costs as if the full 220MW sharing limit is achieved at all times when that will clearly not be the case.

In respect of Option 4 in the WAG paper Meridian supports most elements of the 'Cost-to-island-causers' approach (Option 4 in the WAG's paper) although we suggest that if this option was to be implemented then rather than allocate shared IR costs to risk setters in each island at the same price, shared IR costs should be allocated to risk setters in each island in proportion to the marginal reserve offer price in each island (this is not necessarily the same as the marginal reserve price in each island). This assigns cost to risk in each island in line with the cost they impose on the system (i.e. a risk in a low-priced island should not have to pay the price of the high-priced island if cheap reserve were available in that island – the cost of that risk to the system is comparatively low). This gives a strong incentive to offer in reserves at lowest-cost in both islands. In contrast, as currently formulated Option 4 (and indeed the other allocation methodologies in the WAG's paper) may promote 'pricing up' of reserve offers, particularly for the low-price island to match the higher priced island.

In the example of Option 4 with 120MW of shared IR (100SI, 20NI), and with the SI price at $1 and NI price at $10, then SI risks pick up cost in accordance with their pro rata or runway share of 1/11 x $300 = $27. NI risks and the HVDC pick up costs in accordance with their pro rata or runway share of 10/11 x $300 = $273. This reflects the relatively low cost of risk in the lower-priced island, while reflecting the greater value of shared reserves to the higher-priced island.

As an aside, we note the WAG paper seems to contain an error in discussing this option: on page 42 it provides that

	of the total 400MW of reserve purchased in the situation where the HVDC is transferring 800MW energy, 302MW is solely allocated to NI risk setters and 22MW + 98MW (a total of 120MW) would be allocated nationally i.e. 420MW in total or 20MW more than is required. It seems from the description of this option on page 42 that what is meant is that only 280MW of the reserve purchased in the NI would be allocated solely to NI risk setters. In respect of Option 5 in the WAG paper, 'Cost-to-HVDC-then-to-AC-island-causers' we consider the method of charging is complex, and gives preference to assigning significant proportions of costs to one of the least controllable risks (the HVDC) that in reality are also shareable. It is also an option that in effect exacerbates the underlying inefficiencies of the TPM, making it an unacceptable option until the TPM has been reformed. In addition: • The logic behind this option is difficult to follow. Meridian is unsure why it is accepted in the paper that the co-optimising Scheduling Pricing Dispatch tool (SPD) generates efficient market solutions in its treatment of offers from larger generating plant (see page 25 "SPD determines the least-cost combination of plant to meet demand, and automatically chooses the optimal output of generation and IR procurement simultaneously, based on energy and reserve offer prices") but a different view is taken of the HVDC. Instead, rather than treat the HVDC as an enabler of a (partial) national reserves market, this option seems to posit a full national reserves market and then to treat the HVDC as an 'exacerbator' of IR costs to the extent the current physical limitations of the HVDC mean it does not deliver on that market. However, somewhat illogically, it only does this for one of the current physical limitations of the HVDC (i.e. its inability to transfer reserves to cover a DC CE risk) whereas for the other physical limitation of the HVDC (i.e. its inability to transfer more than 220MW of reserve) it takes this as a 'given'. In the example discussed in the WAG's paper this means that in the situation of 800MW HVDC energy transfer, the HVDC is considered to have 'prevented the procurement of 122MW of cheaper South Island IR' because in that situation the HVDC's inability to transfer reserves to cover the NI DC CE risk of 302MW means that 302MW of NI IR has to be purchased instead of the 180MW of NI IR that has to be purchased when HVDC energy transfer is at 680MW or less i.e. an 'additional' 122MW. It's not clear why the same principle does not require that the full 302MW of ''more expensive' NI IR costs be allocated to the HVDC on the basis that it's other physical limitation (the inability to transfer more than 220MW of IR) is similarly preventing the procurement of cheaper South Island IR. • This method does not adequately satisfy the principle of causer-pays, with the WAG's analysis on page 44 for example establishing a far greater HVDC allocation of costs for a 900 MW transfer level than to NI AC plants (220MW of NI reserve vs 180 MW of NI reserve) – even though each create the same level of risk (400MW of NI reserve). As the WAG recognise in the paper, increased use of the TPM to allocate HVDC-related costs will exacerbate the inefficiencies the Authority has recognised in the current TPM through the long running TPM reform process to date. With any final TPM reforms not due to take effect until 1 April 2019 at the earliest, we do not consider that increasing in the meantime the level of cost allocation via the TPM would be consistent with the Authority's statutory objective unless other alternatives were shown to clearly be even more inefficient. Meridian therefore considers his option would be inappropriate while the current TPM

	remains in place. We also note the current TPM sits at the lowest rung of the EA's hierarchy of preferred approaches to cost allocation. It is not even a 'beneficiaries pay' approach (like the EA's currently proposed new TPM) let alone an 'exacerbators approach'. **Other comments** Meridian notes this consultation question appears on page 45 of the WAG's discussion paper, part way through section 6.2 "HVDC-related issues". In the pages preceding this consultation question, the WAG's discussion paper asserts at page 34, "Transpower [in its role as grid owner] faces strong regulatory incentives to make existing HVDC capacity available. In particular it is obligated under part 12 of the Code to make the full capacity of the HVDC available to the market". No reference within part 12 is given and Meridian has been unable to find a passage in part 12 of the Code that places such an obligation on Transpower in its role as Grid Owner. It would be useful if the WAG could provide a cross-reference for its assertion. Related to this Meridian also notes that WAG's discussion paper asserts, again at page 34, that "Transpower is incentivised under the Part 4 framework to make any new investments that would pass a public net benefit test. Thus, to the extent that the costs of a fourth cable were less than the projected economic benefits, in terms of altered energy and capacity outcomes taking account of any IR impacts, then the regulatory framework would incentivise Transpower to undertake that investment." Meridian has checked this assertion by reviewing the background documents on GIT/modelling for Pole 3 approval. In summary: • Transpower's modelled benefits of a 700MW Pole 3 were $191m. • This was derived from a weighted scenario approach using GEM and SDDP to model costs and benefits over 30 years. • The modelling appears to assume the HVDC operates unconstrained and, under the 700MW Pole 3 option ultimately approved seems to allow up to 1400MW of DC flows overall. • This may in part be due to the purpose of the GIT, which is to identify the highest NPV option and demonstrate the NPV is positive i.e. it may not require a highly sophisticated modelling approach. However it does seem the GEM/SDDP modelling did not incorporate any modelling of reserves and that the original Pole 3 investment case was on the basis of unconstrained use of the nameplate capacity of the HVDC which hasn't been achieved in practice. Further even if Transpower in its role as Grid Owner has the correct incentives, Meridian notes there is no discussion in the WAG's paper of whether Transpower, in its role as System Operator has the correct incentives, particularly in terms of how it models the HVDC for the purposes of calculating reserve requirements. At footnote 20 the paper indicates this is because "…considerations of system operator incentives are not relevant to the cost allocation considerations." On the contrary, Meridian's view is that the HVDC limitations modelled by the System Operator have such a significant impact on reserve costs that it is critical to consider the System Operator's incentives in

	determining the level of these costs when setting a cost allocation framework.
MEUG	No; though we are open to consider options that other submitters may identify.
Nova	Refer to the proposed cap on charges to the large CCGT units.
NZX	No.
Pioneer	*Did not comment*
Transpower	No.
Trustpower	No.

Q7: 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?	
Submitter	**Submitter's comment**
Contact	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.
EnerNOC	Option 5, with the costs on the HVDC going to the sending Island generators. We believe that Option 5 is the most economically efficient approach. It could be significantly enhanced by passing the IR costs caused by the HVDC directly back to the sending Island generators. With this addition, all IR costs for each type of risk should be allocated as a marginal cost per trading period. [see additional comments at end of this table] If the HVDC costs cannot be allocated as a marginal cost signal then Option 2 is the next best market direction for efficient operation for the HVDC. The sending Island will receive some cost allocation from the reserve procured in the receiving island to support the flow over the HVDC. While Option 4 is a good starting point, it dilutes the price signal for the operation of the HVDC as both the generator within the Island risk costs and the HVDC risk cost are included in the one pro-rata allocation. We prefer to see the separation and allocation of each risk type that is present in our ranking of option 5. Option 3 appears to give a rather fixed cost for IR to the South Island, independent of the HVDC operation. In fact, the direct cost to the South Island appears to go down in relationship to the use of the HVDC. Our view is that this approach will not provide meaningful marginal pricing signals. There are questionable incentives placed on participants from the present Island based IR cost allocation approach (Option 1). It remains our view that it is only a matter of time and opportunity before perverse outcomes will be seen.

Genesis	The options that had been indicated to be 'better' (cost-to-island-causer) and 'best' (cost-to-HVDC-then-to-AC-island-causers) are difficult to understand. We fail to see how increasingly complicated solutions, which are not easily explicable for participants of the WAG with in-depth market experience, will send price signals to the underlying causers; particularly when they may not be well understood by the traders who will be making decisions on plants. Option 3 "C" is our preferred option. *[from cover letter]* Our preference is for the WAG to pursue a simple, timely solution, which is targeted to the existing problem. A complicated cost allocation method is likely to result in greater uncertainty for participants, be costly to implement, and simply add another layer of unnecessary complexity to the electricity market for little or no benefit to the end consumer.
Mercury	Option 5 is the most principled followed by option 4.
Meridian	Meridian considers the fundamental issue of unit vs station-based allocation needs to be addressed in order for any cost allocation option to meet the cost allocation principles of section 5. Of the options considered by the WAG then either Option 1 or Option 4: "Cost-to-island-causers" in our view best satisfies criteria regarding efficient price signals. Of these two Meridian suggests Option 1 should remain in place until further analysis is completed. However, subject to that analysis, and with the adjustment specified in our Q6 response, Option 4 should in addition ensure non-distortionary charges that encourage lower costs overall (Meridian's suggested third principle). The WAG's paper states the main drawback with Option 4 is that "it doesn't send a marginal signal to the HVDC that indicates the IR cost implications of high HVDC energy transfers." This criticism would have some force if allocation of costs to the HVDC was more consistent with the underlying 'exacerbators pay' cost allocation principle that the WAG considers should, so far as practically possible, be implemented here. HVDC costs are, however, passed through by Transpower to third parties and are therefore not internalised by Transpower in their decision making relating to the HVDC. Further, neither the current TPM nor the Authority's proposed new TPM allocate HVDC costs using an exacerbators pay methodology. For this reason Meridian believes this criticism misses the mark as it fails to recognise the limitations that are already inherent in using the TPM to allocate IR costs. *[from cover letter]* **A modified 'Cost-to-island-causer' approach is the most appealing of the WAG's other options** The current island-based allocation methodology is Option 1 of 5 cost allocation options identified by the WAG. Of the other four, Meridian considers that a modified version of Option 4 'Cost-to-island-causers' may promote the best

	outcomes. Meridian's proposed modification would involve allocating costs to each island (including to the HVDC in the receiving island) in accordance with the relative marginal offers in each island. This is discussed further below. Without this modification this approach may introduce distortions into participants' reserve offers and the full potential benefits of the NIRM may not be achieved. Option 5 'Cost-to-HVDC-then-to-AC-island-causers' – as it is currently proposed by the WAG – is complex, and gives preference to assigning high proportions of cost to one of the least controllable risks – the HVDC. In addition, we consider: • The proposed approach does not adequately satisfy the principle of 'causer-pays', in certain situations allocating higher costs to the HVDC than to NI AC plants despite both presenting the same (400 MW) level of risk. • The suggestion that the HVDC is 'unique' that is used in justifying this approach is incorrect. The Scheduling Pricing and Dispatch (SPD) process is just as able to generate efficient solutions in dispatching the HVDC as it is when dispatching generating plant. • This option would be inappropriate while the current TPM remains in place. The current TPM sits at the lowest rung of the EA's hierarchy of preferred approaches to cost allocation. It is not even a 'beneficiaries pay' approach (like the EA's currently proposed new TPM) let alone an 'exacerbators approach'. *[from cover letter]* **IR cost allocation options – summary of Meridian views** Meridian's views in respect of the WAG's different IR cost allocation options are set out in the table below. Regardless of which option is chosen Meridian considers the first priority should be replacing the current unit-based reserve cost allocation methodology with a methodology that allocates costs at the station level in accordance with the risk amount or reserve requirement actually driven by that station i.e. in the case of a multi-unit station like Manapouri this would be based on the 120MW reserve costs it actually drives (as adjusted to reflect any de minimis) and not 7 x 120MW that it currently pays. This change can be combined with any of the options in the WAG's paper.

<table>
<tr><td></td><td>
<table>
<tr><th>Option</th><th>Comments</th><th>Meridian ranking</th></tr>
<tr><td>Retaining the current island-based method
(WAG option 1)</td><td>Island-based allocation is a valid and acceptable approach to sustain until a clearly better option is identified</td><td>1</td></tr>
<tr><td>‘Cost-to-island-causers’
(WAG option 4)</td><td>Subject to the modification we have suggested (cost allocation to islands in accordance with relative marginal reserve offers), is likely to promote the best outcomes of all the WAG’s 4 alternative options</td><td>2</td></tr>
<tr><td>‘Cost-to-HVDC-then-to-AC-island-causers’
(WAG option 5)</td><td>A complex approach that poorly targets exacerbators and exacerbates recognised inefficiencies of the current TPM</td><td>3</td></tr>
<tr><td>National allocation – with or without sharing adjustments
(WAG options 2 and 3)</td><td>At least under a unit-based cost allocation, is ineffective in targeting exacerbators and carries high risk of perverse outcomes.
Not supported by Meridian.</td><td>N/A</td></tr>
</table>
</td></tr>
<tr><td>MEUG</td><td>MEUG’s preliminary view is to agree with the preliminary finding in the WAG discussion paper “option 5 (allocating costs to the HVDC then AC island causers) would be the option which best sent a signal to the underlying causers of how much, and where, IR needs to be procured.” As with response to Qu. 6 above we are open to views and analysis of other parties on what, as is demonstrated in the analysis on pp45 to 50, a very complex issue.</td></tr>
<tr><td>Nova</td><td>Nova agrees that option 5, allocating costs to the HVDC then AC Island causers provides the most appropriate price signals to market participants and is the most sustainable over the long term.</td></tr>
<tr><td>NZX</td><td>We have not at this stage developed high level estimates for the options presented. We agree though that none of the options would be excessively complex to implement. Options 3 – 5 will require the clearing manager’s system to access and store additional information. This may need to be either sourced from WITS or the system operator.</td></tr>
</table>

	Option 5 'Cost of HVDC then to AC island causers' appears to offer the most transparent and comprehensive breakdown of how IR costs are allocated. This option has the potential to meet both high level principles of allocating costs to the parties causing the need for IR as well as sending a marginal pricing signal to IR setting generators. One benefit of this option is that it recognises that the HVDC itself does not give rise to the need to procure IR in sending-energy-island and so would not be allocated the cost of procuring IR.
Pioneer	*Did not comment*
Transpower	Our preference is for the third approach to factor in the HVDC sharing to the island allocation; this seems to be a proportionate incremental approach to the current state. *[from cover letter]* We agree with the WAG conclusion to not recommend a change to cost-allocation to the 'runway' approach. We also agree with the WAG observation that the dual nature of the HVDC as causer and provider of Instantaneous Reserve, plus the role of the TPM, makes the design of the marginal signal challenging (maybe impossible!). Our preference would be for incremental change to the current cost allocation approach that takes into account the new capability of the HVDC for IR reserves sharing. This is Option C in the Authority's recent consultation. Fundamentally, the current pro-rata allocation arrived at by negotiation would seem to be a better fit with a hierarchy that puts market-like solutions above any administered approach. We note the difference in views of the WAG and the Authority on the complexity of cost allocation approaches. The Authority had not preferred its 'Option C' (taking into account HVDC sharing) because option C would be considerably more costly than the proposal to implement . In contrast the WAG indicates that in terms of complexity, none of the options are considered to be excessively complex or costly to implement . Our view is that the further variants presented by WAG – indicated as 'Cost-to-island-causers' and 'Cost-to-HVDC-then-to-AC-island-causers' – would be more complicated for predicting (ex-ante) cost allocation, although we defer to generator's expertise on that point.
Trustpower	Probably Option 5 ('Cost-to-HVDC-then-to-AC-island-causers'), because it most closely reflects the technical capabilities and limitations of the HVDC. However, we have some significant reservations, as follows. We would be concerned about the practical implementation of Option 5, because of the extreme "step" nature of the cost allocation once the HVDC flow exceeds 700 MW north. As shown on p48 of the Discussion Paper, Option 5 brings a sudden and significant cost shift onto the HVDC between 700 and 900 MW. We do not consider it to be efficient practice to have such step changes in the allocation method, because this will introduce volatility (hence risk, hence cost) to the co-optimised energy + reserves market as participants seek to avoid the step up in charges (or to load those charges onto others).

	Hence we recommend the WAG favours allocation options that show a smoother continuum of cost allocations as HVDC flows vary.

Q8: 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?	
Submitter	**Submitter's comment**
Contact	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.
EnerNOC	No.
Genesis	There will be supporters for each general cost allocation approach, and there will be (potentially different) supporters for each cost allocation option. To simplify things, these should be kept separate and not impede the implementation for an efficient national cost allocation solution.
Mercury	No we see them as different issues. As described in our response to question three, we are in favour of an expeditious transition to a national cost allocation.
Meridian	No.
MEUG	*Did not comment*
Nova	It does appear that the HVDC then AC Island causers approach to charging is less equitable to generators in the South Island under the pro-rata approach than the runway approach.
NZX	In the long term the general cost allocation approach may have an effect on the inputs of the option chosen due to the fact that it may alter the long term cost structures of the larger North Island thermal generators. However altering the level of inputs is unlikely to significantly affect the decision of which cost allocation method to use. The operation of either a pro-rata or runway approach will not fundamentally affect the operation of any of the options for cost allocation under NMIR.
Pioneer	*Did not comment*
Transpower	Yes.

Trustpower	Yes, and refer answer to Q4.

Q9: 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?	
Submitter	**Submitter's comment**
Contact	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.
EnerNOC	This is the key to the best cost allocation in the long term.
Genesis	We believe this should be considered to a large extent if we are to pursue a 'causer pay' approach.
Mercury	We agree the choice of option is affected by cost allocation to the HVDC but this is very challenging to fix within the IR cost allocation rules and best done through TPM, even if the TPM would send relatively "dull" signals that would not vary trading period by trading period.
Meridian	For reasons already discussed (i.e. the TPM is not an 'exacerbators pay' approach) Meridian considers that IR costs allocated to the HVDC are not currently passed-on to 'underlying causers' of the level of energy transfer across the HVDC. Within any one trading period the level of energy transfer across the HVDC is the product of a complex series of interactions that are optimised via SPD into a least cost solution. In this context it does not make a lot of sense to speak of 'causers' of a certain level of energy transfer across the HVDC. As also discussed above, the HVDC component of the current TPM is recognised by the Authority to involve significant inefficiencies. Until the TPM is reformed, increased allocation of reserve costs to the HVDC will exacerbate the inefficiencies recognised by the Authority. Meridian requests there is further consideration by the Authority of alternatives to the TPM for allocating HVDC reserve costs. Option 5 – the 'Cost-to-HVDC-then-to-AC-island-causers' approach – creates a high level of exposure to the recognised deficiencies of the current TPM and in Meridian's view is not a credible alternative at this point.
MEUG	That is a policy market design issue to be addressed in the review of TPM.
Nova	*Did not comment*

NZX	The choice of the best option should take account of the ability to pass on HVDC costs to 'underlying causers'. It is also important for the new regime to be as transparent and fair as possible as this would not only improve the stability of the market but minimise the potential for legal dispute.
Pioneer	*Did not comment*
Transpower	We agree with the conundrum identified by WAG on the dual nature of HVDC in IR cost creation and the nature of our cost recovery from HVDC payers. We prefer incremental and proportionate change to cost allocation.
Trustpower	No firm view at this stage.

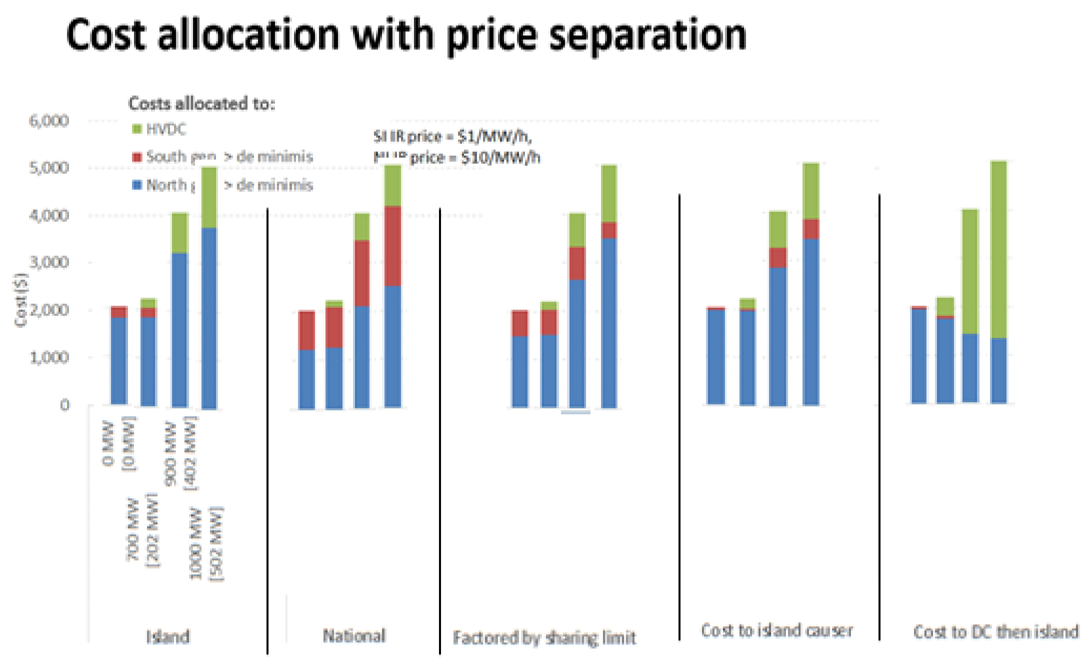
Q10: Do you believe that some IR cost allocation options could materially impact on participants' incentives to offer energy and IR to a degree that could have material outcomes on these markets?	
Submitter	**Submitter's comment**
Contact	Yes.
EnerNOC	Yes.
Genesis	Different IR cost allocation options will likely lead to different outcomes that could be material. It will be hard to predict what each participant will do, so demonstrating such effects will be very difficult. On this basis, we believe a simple, cost reflective solution which broadly and fairly allocates costs is most likely to achieve the desired outcome and align with the Authority's statutory objective.
Mercury	Yes market participants will manage their positions as they see appropriate, this is why any cost allocation regime should be as fair and simple as possible, the greater the complexity the more the scope for unintended consequences and gaming.
Meridian	Yes. Refer our Q6 and Q11 response.
MEUG	*Did not comment*
Nova	We are not aware of circumstances where this might apply.
NZX	No, as the threat of regulatory sanction is likely to be too strong and, as stated in question 3, we believe that the consequences of not generating would outweigh the gains in terms of reduced IR cost allocation.
Pioneer	*Did not comment*
Transpower	No comment.
Trustpower	Yes. Some IR cost allocation options (especially Option 5) would produce step changes in the charge allocation due to the non-linear nature of the HVDC capabilities. Refer 7.2 above. Any such step changes could be expected to have a material effect on market offer behaviour and should therefore be avoided.

Q11: If yes, which options are likely to give rise to such outcomes, and could you provide worked examples demonstrating such effects?	
Submitter	**Submitter's comment**
Contact	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).
EnerNOC	All the remaining proposed options, 1 to 4.
Genesis	See Q10.
Mercury	No comment.
Meridian	Options 2, 3 and 5 - 'national allocation', 'factored by HVDC reserve sharing limits', and 'Cost-to-HVDC-then-to-AC-island-causers' - all have the potential to create charges that are highly disproportionate to the level of risks / costs created. The scale of the impact will at times be significant, and provide participants with little choice than to consider all options available for managing those costs - whether reserves or energy offers, or even operational decisions (reduced volumes or capacity). As we detail in our Q6 response, modifications to the 'Cost-to-island-causer' option (option 4) are required to counteract the potential for perverse impacts on reserve pricing. Meridian would be happy to present to the WAG on impacts of the various proposed approaches.
MEUG	*Did not comment*
Nova	N/A
NZX	N/A
Pioneer	*Did not comment*
Transpower	No comment.
Trustpower	Options 2,3 and 4 would appear to have smoother allocation proportions across all HVDC flows, and hence would be preferable in this sense compared to Options 1 or 5. But this result depends on a range of factors, e.g., whether pro-rata or runway allocation used, and whether NI thermals remain in service. Refer Figs 21-23 on pp.48/49 of

Discussion Paper.

We do not have any specific examples of material market outcomes to illustrate these points, but simply recommend that the WAG considers the unpredictability of the market effects of step changes in cost quanta/proportions as HVDC flows vary.

The chart below (derived from the Discussion Paper Fig 21) illustrates the more extreme step changes in allocation that are likely under Options 1 or 5 (left and rightmost sections, respectively)).



Q12: 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?	
Submitter	**Submitter's comment**
Contact	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.
EnerNOC	No.
Genesis	Key decisions are yet to be made in regards to TPM which will affect the degree to which this approach will reflect the 'causer pay' principle. Ultimately it will leave the allocation to the TPM, which may not follow the same principles set up under the NMIR.
Mercury	Per our response to question nine, we agree that HVDC-related IR costs should continue to be allocated to the HVDC owner and then redistributed via the TPM. In terms of the interim allocation of costs under the NMIR, as described in our response to question three, we are in favour of an expeditious transition to a national cost allocation.
Meridian	See our response to Q8. *[from cover letter]* Meridian also considers that, in the context of a 'causers pay' approach, allocation of costs to the HVDC and recovery of those costs through the TPM is problematic. All of the options in the WAG paper involve significant allocation of costs to the HVDC and recovery of those costs from the parties who meet the costs of the HVDC under the TPM. The current TPM sits at the lowest rung of the EA's hierarchy of preferred cost allocation approaches. Even if the EA's currently proposed reforms are adopted (1 April 2019 at the earliest) the TPM will be a 'beneficiaries pay' methodology not a 'causers pay' methodology. Having such a methodology sit at the heart of 'causers pay' approach to IR cost allocation is a fundamental inconsistency. We suggest that other cost allocation options should be considered that have the potential to resolve this inconsistency (e.g. by allocating costs that would have been allocated to the HVDC nationally amongst all generators).
MEUG	See response to Qu. 9.
Nova	The key disadvantage of allocating the HVDC-related IR costs via the TPM is that there is no price signal created to

	incentivise a change in behaviours. The connection between the generation offers, or demand decisions are too remote from the TPM to affect market behaviours. Nova believes it would be more appropriate to allocate the costs to generators in the sending Island on a half hourly basis. In this way those generators can be expected to moderate their generation offers in response to the expected costs during very high HVDC transfers. In the longer term this would also influence generation build decisions. Demand, is unlikely to respond to an allocation of HVDC IR costs, and therefore it is not worth the additional complexity of allocating that.
NZX	No comment.
Pioneer	*Did not comment*
Transpower	Yes, under the pro-rata approach. The Code obligation on capacity means HVDC owner has no ability to manage greater cost exposure of the runway approach.
Trustpower	This is a complicated issue that overlaps with the TPM. No firm view at this stage.

Q13: 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?	
Submitter	**Submitter's comment**
Contact	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.
EnerNOC	Remain the same.
Genesis	Option a, continue as is. Commissioning of large thermal plant is extremely unlikely in the near future.
Mercury	Option a) because it is the simplest and there is no clear case of the benefits outweighing the costs of making a change, particularly since commissioning events are relatively uncommon on the system in the grand scheme of things.
Meridian	Meridian considers that commissioning plant should be changed to be quantity-and-price-runway-based or quantity-runway-based, depending on which is the more cost effective option to administer. See also our Q1 response for further comments. *[from cover letter]* Commissioning plant 'causers' of secondary event risks have potential to create high IR costs and should be charged using a cost effective method of allocation.
MEUG	A change to a quantity-and-price-runway approach for plant being commissioned best meets the two principles we agreed with in response to Qu. 2 above. However there are also additional costs in having the "price" leg of the approach and therefore net benefits may be maximised with just a quantity-runway based approach. The choice should be decided with a more detailed CBA.
Nova	The cost allocation for commissioning plant should change to be quantity-runway-based, with application of a de minimis. The rationale for retaining a de minims is as per question 5.
NZX	Our preferred option is c).
Pioneer	*Did not comment*
Transpower	Continue as is.

Trustpower	No firm view at this stage.

Q14: 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?	
Submitter	**Submitter's comment**
Contact	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.
EnerNOC	*Did not comment*
Genesis	As above; we do not believe there is sufficient premise to support further investigation and changes to cost allocation for commissioning plant.
Mercury	Yes, but we do not support general cost allocation moving to a runway basis.
Meridian	No. To the extent it is cost effective to do so, the runway method of charging should be utilised for commissioning plant, irrespective of the general cost allocation approach used.
MEUG	See response to Qu. 13.
Nova	Yes. The commissioning charge methodology should be consistent with the basis for general cost allocation.
NZX	Yes, running multiple methodologies adds to the complexity and therefore cost of any IR cost allocation scheme.
Pioneer	*Did not comment*
Transpower	Yes.
Trustpower	No firm view at this stage.

Q15: What cost-allocation approach do you think should apply for plant with under-frequency and voltage-fault-ride-through dispensations?	
Submitter	**Submitter's comment**
Contact	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.
EnerNOC	*Did not comment*
Genesis	We support the existing arrangements.
Mercury	Voltage and frequency are two different variables with some overlap in an under frequency event. To the extent that a voltage fault ride through non-compliance drives increased under frequency reserve procurement (because an under frequency event may cause a voltage event which then causes voltage non-compliant plant to trip), we favour such non-compliant plant being allocated IR costs. It may be very difficult to model precisely how an under frequency event might then cause a voltage related plant trip, so it may be expedient and prudent to treat plants with voltage dispensations as having frequency dispensations. However, along with the above, there should be a separate consideration for allocation of cost for addressing voltage event non-compliance for the plants with dispensation.
Meridian	Meridian agrees with the WAG's view – that is, where IR costs are created, these should be recovered from causers in a way that is cost-effective. For plant with dispensations from under frequency (8.19) AOPO obligations, it is unclear how aspects of the SO's recently determined interim approach will operate (in particular whether "the greater of the two island costs" is to be derived from aggregated quantities at the higher price, or the relevant quantity in each island at each island's price). This requires clarification. In any event, Meridian's view is that the principle of causer-pays dictates that these amounts should instead be charged at the sum of the two amounts, that is the summed value of the relevant island quantity at the relevant island price within each island. For Meridian's White Hill wind farm in particular, the manual processes that need to be followed by the SO in assigning allocations may also create a need for further potential adjustment. With new voltage-fault-ride-through standards, it is important that asset owners are provided with clarity and consulted as soon as practical on the specific methodologies that may be used for IR cost allocation so they can make informed decisions on investing or seeking dispensations.

	[from cover letter] In terms of the other categories of secondary risk causers identified by the WAG, we agree with the principle that IR costs should be recovered from causers where it is cost effective to do so. We share the WAG's view that this criteria is unlikely to be met for smaller plant (< 30 MW), requiring alternative approaches to be considered.
MEUG	*Did not comment*
Nova	It is appropriate that plant with dispensations should be allocated a proportion of reserve costs. A crude-proxy approach would seem appropriate, as long as there is a reasonable expectation that the given formula is not going to penalise the dispensation holder in excess of what might have been expected on a fully allocated basis. Such a proxy should also be reasonably straightforward for the parties to understand in relationship to market prices for IR.
NZX	No comment.
Pioneer	*Did not comment*
Transpower	No comment.
Trustpower	No firm view at this stage.

Q16: 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?	
Submitter	**Submitter's comment**
Contact	The code currently has provisions to manage this issue by the EA invoking clause 8.38.
EnerNOC	*Did not comment*
Genesis	Our preference is Option 3 or 2 (to cover 10MW onwards or even less). The implementation cost should not be high as these options will be extending an existing methodology.
Mercury	We support doing nothing as small plants do not have a material impact that would justify the expense of developing, consulting on and implementing special measures.
Meridian	The secondary CE risks from smaller plant (< 30 MW) may create high system costs and need to be addressed. In terms of the specific measures that should be implemented, Meridian agrees with the WAG's assessment that there are alternative courses of action (in particular more extensive adoption of AOPO standards) that should be pursued ahead of changes to IR cost allocation to target the risks small generation plant can present.
MEUG	*Did not comment*
Nova	In principle, if the cost of non-compliance can be directly attributed to a generating station then the market participant should be charged for that cost. That is not to say that the default dispensation for all plant below 30MW needs to be removed. Clause 8.38 should instead need to be modified to enable the Authority to require any generating station that is clearly creating additional costs to either meet the AOPO (as clause 8.38 stands) or mitigated (i.e. pay for the impact, which may be a lower cost option). It is expected that in most cases, those excluded generating stations with dispensations do not create readily identifiable additional costs for the rest of the market.
NZX	The cost of gearing a system designed to encapsulate the smaller generators that are currently excluded would likely outweigh the benefits of complete compliance with frequency-related AOPOs.
Pioneer	The paper analyses the potential impact of assets excluded from complying with AOPOs (pg 59-60). Pioneer agrees that efforts should be made to reduce the system cost of having to procure extra IR to cover a contingent event. However, the Code includes a well-established process for the system operator to work with any generator to

	resolve any non-compliance with the AOPOs. By making enquiries, the system operator was able to establish that Pioneer's two wind farms (of less than 10MW each) do have acceptable protection systems in place to ride through a fault and maintain output. The current ride through requirements on small generators are sufficient to minimise the impact of these generating plant on the overall system. Pioneer submits that no new measures need to be implemented to address small generation plant that is currently excluded from the need to comply with frequency-related AOPOs. The Code already enables the system operator to gather the information it needs to determine what steps it or the plant owner should make to manage non-compliance with frequency-related AOPOs.
Transpower	No comment.
Trustpower	No firm view at this stage.

Q17: Do you think the event charge should be retained, and if so, on what basis?	
Submitter	**Submitter's comment**
Contact	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.
EnerNOC	Retaining the event charge can provide an additional commercial driver towards plant reliability. If it is decided to retain the event charge to maintain a reliability price signal to the causers of IR events, then it should be redistributed to all the providers of IR. Both the spinning reserve and Interruptible Load providers should receive in proportion to their delivery during the under frequency event, a share of the costs. This goes some way to rewarding the faster IL response in arresting the frequency fall during the event. (Proposed Code Changes to amend the allocation of the event charge in subpart 3 of part 8 of the Code, EnerNOC, updated in March 2016)
Genesis	We do not support retention if there is no compelling case to keep it, particularly if the number of events has been very low.
Mercury	This is a low priority but ideally the event charge rebate should go to reserve providers not reserve causers as it is

	wrong in principle to pay participants just for having plant that does not trip. The event charge seems arbitrary but the costs of addressing this issue are likely to outweigh any benefits given the regime is rarely utilised.
Meridian	Yes. The event charge as a construct is more in keeping with causer pays, although it is not clear the extent to which this is achieved in practice due to: a) The practice of re-allocating the event charge back to event causers providing payment for reserves. b) The $1,250 per MW lost charge which has remained unchanged for some time and may no longer reflect an appropriate assignment of costs. Further assessment of the legitimacy of the specific event charge level and provision of rebates to event causers is therefore required. Levying event charges for the HVDC also needs to be revisited. The direct pass through of costs using the TPM means that HVDC event charges are of no material consequence for incentives for reliability and do not target actual causers. Re-assigning event charges to IL providers under current IL procurement methods is not a justifiable approach and is not supported by Meridian. Allocating event charges to IL providers should be revisited if a new event-based procurement approach was able to be demonstrated to be of benefit. Meridian considers, however, the case for introducing event-based procurement has yet to be made.
MEUG	The preliminary view of MEUG is the event charge should not be retained provided a change to a runway approach is adopted. A change to the runway methodology for all procurement costs gives a time consistent better marginal cost signal to likely exacerbators than the current status quo mix of pro-rata allocation subject to a de minimus with event charges. Put another way if the current pro-rata cost allocation is retained then so too should an event charge to provide some sort of marginal cost signal. On another related topic MEUG suggests there is value in the market and the EA understanding who was the causer, the reasons for and the magnitude of all events. At the moment those statistics are collected and used for the purpose of deciding which party and how much they should pay for event charges. Ceasing collection of those statistics (except value of event charge) would be a mistake because having that information provides a useful history of actual outcomes to assess the performance of changes to the regime and if necessary further changes.
Nova	Nova disagrees that the current event charge does not provide a cost reflective incentive for plant to be maintained to a reliable standard. It believes the event charge should be maintained and rebated back to the payers of IR as currently. The discussion paper provides the example: 'generators might withdraw their plant from operation for fear of incurring an event charge if they were to trip' – surely in such circumstances it is desirable to incentivise the

	generator to withdraw its plant if the probability of a trip times the event charge exceeds the expected revenue from generation. The only exception to this is the HVDC, where there are regulated incentives for performance. It may be appropriate to review the amount of the event charge, and whether it should apply to any plant that trips, over the 60 MW de minimis, rather than to just those trips that cause under frequency events.
NZX	NZX agrees with the WAG assessment that an event charge is not an appropriate tool to incentivise reliability. Past events have demonstrated the difficulty of trying to apply an event charge in a cost effective way. Unique circumstances resulting in special scenarios and potential legal costs have meant that the cost of investigating and applying the event cost more than likely outweighs its benefit. The economic consequences of a plant tripping off are likely incentive enough for generators with dispatch flexibility to prioritise reliability.
Pioneer	Pioneer agrees with the conclusion to discontinue with the event charge. The number of under-frequency events is low and the proportion of costs recovered by this charge has been less than 15% for the last four years (excluding 2013 when one-off commissioning of the HVDC caused an increase in under-frequency events).
Transpower	Unsure. *[from cover letter]* We support the WAG consideration of whether the event charge is still necessary given the presence of commercial and regulatory drivers for asset reliability. We agree too with the recognition of the costs associated with the event causer determination process, including legal challenge. However, the WAG has drawn a strong conclusion on there being no need to continue with the event charge from relying on analysis that is not fully developed in the consultation paper. From the perspective of system operations, we consider the event charge makes a positive contribution to system reliability. To alleviate our concern for potential reliability risk from the charge removal we suggest the analysis relied on by WAG (via footnote 38 in the paper) needs to be made public. This will assist confidence in the 'remove' conclusion. In addition, the other advisory group, the Security and Reliability Council, could also be asked for its view on event charge removal.
Trustpower	No firm view at this stage.
Other comments made in submissions (from submitters' cover letters)	
Submitter	**Submitter's comment**

Contact	*n/a*
EnerNOC	It is EnerNOC's view that the incentives and IR costs should be better aligned with the causers or risk setters in the market by including more separation of the costs associated with each risk. A long term solution for IR cost allocation should be derived from first principles. EnerNOC believes that the following principles should be applied: • The IR costs should be allocated to the identifiable causer of the need for the reserve, • IR cost should be allocated based on the identified risk that the reserve being procured is covering, • The full cost of IR procurement including the HVDC costs should be delivered in each trading period to deliver the best possible marginal price signal. It is important to separate the IR costs that are relevant to the risk, viz: • In each Island, • When reserve is shared across the HVDC, • When the HVDC requires reserve to be procured in the receiving Island. In separating these three costs, they can be allocated to the fundamental causers of those risks. The present Island based approach to identifying the causers as the North and South Island generators above a 60MW de-minimis and the HVDC above its self-insurance level is not robust enough to provide long term benefits. EnerNOC believes that a new class of causer is required and that is a HVDC causer. The HVDC causer could be identified as all generation above a de-minimis of 1MW in the sending Island. As the WAG paper has proposed, there is little point in passing the cost from the operation of the HVDC to Transpower as they do not have any operational control of the power flows on the HVDC. By passing these costs onto the HVDC to be allocated under the TPM, the marginal price signal is not just blunted, in EnerNOC's opinion it is lost completely from the market through the aggregation with other TPM based HVDC costs. The flows over the HVDC are a direct result of the interaction and optimisation of the energy and reserve offers in both Islands and the prices that result from those offers. If the sender of the next MW over the HVDC is exposed to an increase in reserve cost (from the transmission of that MW over the HVDC for example due to moving into a new price tranche), then they are the ones best placed to include that additional portfolio cost in their energy offer. Aligning the marginal cost of additional reserve directly with energy offers provides a true marginal price signal. Competitive price signals will drive efficient market outcomes. Therefore, the most effective participants to pass the HVDC direct IR costs onto are the generators in the sending Island and this should lead to the most efficient solution for all consumers.

EnerNOC	The Review of the IR markets project along with a possible new IR product design (ie Area under the Curve) for a single IR product should be given priority in the Electricity Authority's 2016/17 work programme [Review of Instantaneous Reserve Markets Recommendations paper from WAG, January 2015]. EnerNOC is not satisfied that this project has received the robust discussion that this market design deserves if we are going to deliver long term benefits for all consumers in the procurement of IR.
Genesis	Genesis Energy supports the WAG's principled review of the instantaneous reserve regime, and appreciates the WAG's willingness to engage with sector participants to develop a balanced understanding of the current IR market.
Mercury	As the WAG has noted there is significant inherent complexity associated with IR cost allocation due to the complex dynamics of the HVDC as both IR provider and risk setter, and the interrelationship between the energy markets and the different portfolio effects on different participants. It is important that any changes do not increase complexity as any increase in complexity is likely to increase the scope for unintended consequences and to allow market participants to search for ways to maximise their own advantage at the expense of the common good. We strongly support a cost allocation regime that is fair and simple.
Meridian	The need for thorough assessment and consideration of changes to current arrangements Averaging $38 million annually for the period 2008-2015, procurement costs of Instantaneous Reserves (IR) are material. The potential for IR cost allocation methods to create wider energy market distortions and reduce the benefits obtained from a national reserves market is real. Meridian fully supports continuing the use of the current, well-established island-based allocation method while the WAG and ultimately the EA undertakes thorough and detailed assessment of potential changes. We appreciate the WAG's engagement with industry and detailed work in support of the review so far. However, as the WAG's paper acknowledges, the WAG is at an early stage of its considerations. It will be important that industry has the opportunity to provide input into the next iteration of the WAG's and / or the EA's proposals. As we mention in our detailed feedback attached, Meridian would be happy to present to the WAG on our views of the options from this consultation. Like the WAG, Meridian considers there are two principles that should be followed in allocating IR costs: 1. Costs would be allocated to parties causing (or exacerbating) the need for IR; and 2. The cost allocation would send a marginal signal. Meridian agrees this should drive the most efficient outcomes. As discussed below Meridian proposes a third principle or test of the outcomes produced by the application of these first two principles namely that "Cost allocation arrangements need to be non-distortionary and promote efficient market outcomes." This additional test / objective needs to be applied broadly – within the reserves and energy markets and also to confirm utilisation of

	greater HVDC capacity is appropriately incentivised.
Meridian	Unit-based allocation is a critical flaw of existing arrangements The WAG in its paper focuses on three potential problems with the existing method of general cost allocation: 1. dulling of price signals for causers of IR costs from use of the general IR pro-rata cost allocation approach; 2. dulling / distortion of price signals from use of the Transmission Pricing Methodology (TPM) to pass through HVDC IR costs; and 3. inconsistencies in the allocation of IR costs to assets presenting secondary event risks. Of fundamental importance in defining the problems here is ensuring that cost allocations do not stand in the way of realising expected benefits from a national IR market – i.e. more efficient reserve procurement and cost allocation overall – or encourage distortions in reserve / energy markets. Seen in this context there is, in Meridian's view, a fourth significant problem with the existing method of general cost allocation, namely unit-based charging. As noted by the WAG, the application of unit-based charging escalates charges for multi-unit stations like Manapouri and Benmore to levels well in excess of the level dictated by the risk amount for those stations that is used for procurement purposes (i.e. 7 times the 120 MW risk amount or reserve requirement in the case of Manapouri – which exceeds, by some considerable margin, the allocation for stations with a unit creating a 400 MW reserve requirement). The WAG paper considers this problem is a consequence of the pro-rata approach (see page 30) and accepts it is a departure from the 'causers pay' principle. While Meridian agrees it is a clear departure from that principle we do not see it as a necessary consequence of the pro-rata approach. A better, more 'causers pay' application of the pro rata approach would allocate costs to a station in accordance with the risk amount or reserve requirement actually driven by that stations. This is more consistent with and reflective of the level of reserve costs actually driven by a particular station (i.e. a 7 unit station with 7 x 120MW units actually only drives a reserve requirement of 120MW, the same level of reserve cost as a station with a single 120MW unit). In Meridian's view this problem is arguably the most significant of all the potential problems with the current cost allocation methodology and, if there is to be any change, it needs to be addressed as a first priority.
Meridian	Current island-based allocations mask unit-based allocation impacts and remain a valid choice Meridian agrees with the WAG's assessment that maintaining the current island-based allocation methodology is unlikely to impact negatively on incentives within the energy or reserve markets. Experience to date with the operation of the NIRM has proved this assessment to be correct. As the WAG recognises, due to the current technical and physical limitations of the HVDC, the NIRM does not and will not operate as a fully "national" market. There is therefore no "automatic" requirement for cost allocation to be

	on a national basis and no reason why an island-based method cannot be retained, whether on an interim or longer-term basis at least until there is some confidence that a better alternative has been clearly identified. As stated above Meridian considers that there is a strong case for the WAG to recommend amendments to the current unit-based method of allocating costs. In terms of other proposed changes we consider further analysis is required and that in the meantime maintaining the current island-based approach remains a legitimate choice. As recognised by the WAG, the current island-based allocation also has the 'happy coincidence' that it masks the problems with unit-based allocation because the profile of risk setters in each island currently happens to be the same – see page 30 of the WAG's paper.
MEUG	MEUG notes that the discussion paper "contains the preliminary findings from the WAG's review of these arrangements" and the paper was prepared prior to the introduction of a national market for IR (NMIR). Correspondingly the MEUG responses below are preliminary and without experience gained from observing actual outcomes since NMIR began on 20 October 2016.
Nova	*n/a*
NZX	We encourage the Authority to engage with stakeholders throughout the design and implementation phases of any change to the current methodology and to make sure the resulting design is both as simple as possible and fit for purpose.
Pioneer	*n/a*
Transpower	*n/a*
Trustpower	This is a complicated topic, and one which overlaps to some degree with the Authority's ongoing Transmission Pricing Review and Review of IR Markets. Consequently, we have not yet formed a view on some of the issues raised in the WAG discussion paper.