Instantaneous reserve cost allocation to groups of generating units

Consultation paper

22 July 2024

ELECTRICITY AUTHORITY
TE MANA HIKO

Executive summary

The Electricity Authority Te Mana Hiko (Authority) seeks your views on our proposal to amend the Electricity Industry Participation Code 2010 (Code). Our proposed amendment would update the way instantaneous reserve (IR) procurement costs are allocated to generators. This aims to level the playing field between different generators and further strengthen the resilience of the grid. Consumers would benefit from this change through a more affordable and reliable supply of electricity.

Electricity supply and demand need to be in balance at all times. If a generating plant or the High Voltage Direct Current (HVDC) fails suddenly (a 'contingent event', or 'CE'), the grid's frequency can fall and ultimately that can result in the power going out.

The Electricity Authority-contracted system operator procures IR to ensure that consumers' electricity supply is not impacted in the event of a sudden loss of generation or transmission. IR can either be generation that is not operating at full capacity but is available to increase output when required, or load that is available to be reduced when required.

Historically, the costs of procuring IR have been allocated to most of the parties whose potential loss of generation causes the need for IR procurement.

However, as generation technology has evolved, the cost allocation methodology in the Code has not kept pace. This has led to an increasing number of potential event causers with no obligation to pay their share of the total IR procurement cost.

To date, this has included most wind farms, and we expect it will also apply to large solar farms in the future, depending on how they intend to connect to the grid. Under the current arrangements, the proportion of generators not paying a share of IR costs could increase sharply in the future as the market continues to evolve.[1]

The Authority is proposing to amend the Code so more of the causers of IR procurement are required to pay an appropriate share of the IR procurement costs, both now and in the future.

We consider our proposal would better reflect the intent of IR cost allocation – to incentivise causers to act in a way that reduces IR procurement costs, while maintaining a level playing field between different types of generators.

For example, investors may be incentivised to build two connection lines for a future wind or solar farm instead of one. The investor would be incentivised to do this because they would not have to pay a share of IR costs for the potential loss of their generation, as it would not be considered a CE risk. This may then lead to the system operator procuring less IR, reducing procurement costs.

Our proposal may also incentivise generators to offer more IR so that they receive a share of IR payments to offset their share of IR costs. The increased IR offers could come from their existing generation or investment in new flexible generation (as generation like solar and

[1] Our generation investment pipeline report indicates there is around 5,000GWh of committed investment expected to be commissioned by 2025. Of this, nearly half of the supply is expected to be from solar and wind generation. https://www.ea.govt.nz/documents/4414/Generation_Investment_Survey_-_2023_update.pdf

wind that is not flexible cannot offer reserves). We consider this will solidify business cases for BESS to be built alongside solar generation. With more IR offered, the costs of procuring IR may reduce.

Through incentivising greater investment in flexibility, our proposal supports a more secure power system by helping to ensure sufficient generation is available to meet peak demand during low sun and wind conditions.

This is particularly important as more variable renewable generation such as wind and solar farms are built to meet increasing demand for electricity as New Zealand electrifies its economy. The Authority's recent investment pipeline survey indicates a significant increase in large-scale wind and solar generation coming online in the future.

Our proposal is also consistent with the Authority's decision in 2022 to implement a new Transmission Pricing Methodology (TPM), as it helps avoid incentivising participants to take inefficient actions to avoid costs.[2] This is because under the current arrangements, investors may be incentivised to build higher-cost generation to avoid paying a share of IR costs, even if this generation required the same IR cover as the alternative.

The Authority is not currently seeking to make changes to the IR cost allocation methodology more broadly or to the event charge. The Authority is focusing on the immediate issues to ensure participants receive early clarity and a timely change to their likely IR cost allocation, supporting efficient investment decisions. Any further work to enhance the cost allocation methodology, or the event charge, will form part of our on-going work plan.

In the interim, we intend to monitor the effectiveness of these proposed amendments, should they be made, and will consider accelerating this further work should we not see the expected benefits.

Next steps

The consultation is open until 5pm on 30 August 2024. This is a six-week consultation period including five weeks for initial submissions, due by 3pm on 23 August. This will be followed by one week for cross-submissions, to allow stakeholders to provide feedback on views expressed by other stakeholders.

Your feedback will inform the Authority's decision-making on allocating costs to groups of generating units.

[2] Under the previous TPM, transmission customers made costly investments such as purchasing expensive generation in order to avoid their transmission charges. However, this did not typically result in lower transmission costs, instead the net result was an increase in total costs to the system. See TPM decision paper.

Contents

1. What you need to know to make a submission

What this consultation is about

1.1. The Electricity Authority Te Mana Hiko (Authority) is proposing an amendment to the Electricity Industry Participation Code 2010 (Code) to expand the IR cost allocation method.

1.2. Our proposal aims to ensure all generators, whose size and configuration would require IR to insure against consumer supply impacts should they trip, pay an appropriate share of the costs of procuring that IR. This promotes all three limbs of our main statutory objective as follows:

(a) **competition** between different technologies is improved by removing the financial advantages afforded to some technologies.

(b) **reliability** is improved by incentivising more of the potential causers of IR procurement to act to reduce the size of system risks

(c) **efficient operation** is improved by incentivising more of the causers of IR costs to act to reduce IR costs by offering more IR.

1.3. Section 39(1)(c) of the Electricity Industry Act 2010 (the Act) requires the Authority to consult on any proposed amendment to the Code and corresponding regulatory statement. Section 39(2) provides that the regulatory statement must include a statement of the objectives of the proposed amendment, an evaluation of the costs and benefits of the proposed amendment, and an evaluation of alternative means of achieving the objectives of the proposed amendment. The regulatory statement is set out in part 3 of this paper.

The Authority's scope for changes targets the immediate issues

1.1. At this time, the Authority is not seeking to make changes to the IR cost allocation methodology beyond addressing the immediate issue - that groups of generating units do not receive allocations based on the size of the CE risk their generation poses.

1.2. This means for example we are not looking to change the '60MW subtractor'. Allocations to generators are based on a formula in the Code that subtracts 60MW from their average generation in the trading period. Under our proposed amendment this 60MW subtractor would also apply to the total generation from a group of generating units whose simultaneous loss is treated as a CE.

1.3. The 60MW subtractor incentivises investors looking to build a certain capacity of generation to do so with lower risk plant, rather than higher risk plant. We consider it important to provide these incentives but acknowledge the 60MW subtractor is an imperfect mechanism to achieve this objective.

1.4. We are also not looking to investigate changes to the event charge at this stage. When an event occurs, there is a charge to the causer of the event (either a generator or the grid owner). Whereas the allocation of IR costs incentivises investment in plant that pose a lower CE risk, the event charge incentivises investment in plant that cause fewer system events.

1.5. The Authority is focusing on the immediate issues to ensure participants receive early clarity and a timely change to their likely IR cost allocation, supporting efficient investment decisions. Any further work to enhance the cost allocation methodology, or the event charge, will form part of our on-going work plan.

1.6. In the interim, we intend to monitor the effectiveness of these proposed amendments, should they be made, and will consider accelerating this further work should we not see the expected benefits.

How to make a submission

1.7. The Authority's preference is to receive submissions in electronic format (Microsoft Word) in the format shown in Appendix D. Submissions in electronic form should be emailed to OperationsConsult@ea.govt.nz with "Consultation Paper: IR cost allocation to groups of generating units" in the subject line.

1.8. If you cannot send your submission electronically, please contact the Authority (OperationsConsult@ea.govt.nz or 04 460 8860) to discuss alternative arrangements.

1.9. Please note the Authority intends to publish all submissions it receives. If you consider that the Authority should not publish any part of your submission, please:

(a) indicate which part should not be published,

(b) explain why you consider we should not publish that part, and

(c) provide a version of your submission that the Authority can publish (if we agree not to publish your full submission).

1.10. If you indicate part of your submission should not be published, the Authority will discuss this with you before deciding whether to not publish that part of your submission.

1.11. However, please note that all submissions received by the Authority, including any parts that the Authority does not publish, can be requested under the Official Information Act 1982. This means the Authority would be required to release material not published unless good reason existed under the Official Information Act to withhold it. The Authority would normally consult with you before releasing any material that you said should not be published.

When to make a submission

1.12. Please deliver your initial submission by 3pm on 23 August 2024. Please deliver your cross-submissions by 5pm on 30 August.

1.13. Authority staff will acknowledge receipt of all submissions electronically. Please contact the Authority by emailing OperationsConsult@ea.govt.nz or phoning 04 460 8860 if you do not receive electronic acknowledgement of your submission within two business days.

2. Background

Instantaneous Reserves procurement

2.1. The Electricity Authority-contracted system operator procures IR to insure against the risk to consumer supply of a sudden loss of generation event. The system operator classifies these events as ‘contingent events’ (CEs).

2.2. IR can be provided by either generation that is not operating at full capacity but is available to increase output when required, or load that is available to be reduced when required to quickly rebalance supply and demand for electricity following a sudden loss of generation.

2.3. The system operator procures enough IR to cover the largest of these events. This process ensures there is enough IR procured to cover any single event of that size or smaller. This procurement happens dynamically in real-time to ensure the least overall cost combination of energy and IR is procured.

2.4. The system operator sometimes procures IR for extended contingent events (ECE), although the IR required for ECEs is typically low. ECEs are very large but rare events, such as the failure of the entire HVDC link, for which the system operator generally considers it more efficient to allow some consumer supply to be cut off, rather than procuring IR to prevent it.[3]

Availability costs are currently allocated based on how much IR is needed

2.5. Under the Code, the costs incurred by the system operator in procuring IR are referred to as the ‘availability cost’.[4] The availability cost is calculated for each trading period in each island for each month.

2.6. Availability costs are allocated based on a causer-pays principle – that costs should be allocated proportionally to those participants whose generation or transmission are considered a CE risk, based on how much IR is needed to cover the potential loss of injections resulting from the CE.

2.7. The current methodology allocates costs for each trading period to generators and the HVDC owner. The allocations to generators are based on their injections from individual generating units above 60MW.[5] The allocations to the HVDC owner are based on the HVDC transfer that would be lost due to the loss of a

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3 For ECEs, the system operator allows up to 32% of consumer supply to be lost via automatic under frequency load shedding (AUFLS) by electricity distribution companies and industrial loads. This helps prevent an island or nationwide black-out event of longer duration. IR requirements for ECEs are low because the load lost through AUFLS helps to restore the supply-demand balance. See the definition of automatic under frequency load shedding in Part 1 of the Code, and clause 12.3 of the Policy Statement 2022 for more information.

4 Availability cost is defined in Part 1 of the Code. These costs could include those for dispatched IR at the market price and constrained on payments.

5 It is considered that the sudden loss of 60MW, or less, poses no risk to consumer supply as the power system is resilient enough to accommodate it.

single HVDC pole.[6] Historically, these have been the main CE risks requiring IR procurement.

2.8. In this way, the availability cost has been allocated to most parties that are ‘potential causers’ of a contingent event, based on the risk they pose.

Intent of IR cost allocation

2.9. The Authority considers the intent of cost allocation is to incentivise actions that reduce IR costs, while maintaining a level playing field between different generation technologies and configurations.

2.10. The current methodology roughly meets the intent by:

(a) allocating costs to causers based on the risk they pose (as discussed above)

(b) subtracting 60MW from the risk to get the final allocation (ie. applying a ‘60MW subtractor’).

2.11. By subtracting 60MW from the size of the risk, parties are incentivised to invest in a greater number of small generating units, rather than fewer large units to achieve the same generating capacity. This is because they would receive a lower total allocation of IR costs by doing so.

2.12. Having larger numbers of smaller generating units should provide increased resilience as a single failure will have less impact on the power system.

2.13. Investment in lower risk plant can then result in less need to procure reserves, which results in a lower cost of supplying electricity to consumers over the working life of the units. This incentive would be balanced against the relative cost of buying, installing and maintaining two smaller units.

How the 60MW subtractor incentivises investment in lower risk plant

2.14. The following example demonstrates how the 60MW subtractor incentivises investors looking to build a certain capacity of generation to do so with lower risk plant, rather than higher risk plant. The example shows how the total allocations would differ for investment in two 100MW generating units compared to a single 200MW generating unit.

(a) The allocation for a 200MW plant = 200 – 60 = 140MW

(b) The allocation for a 100MW plant = 100 – 60 = 40MW

(c) The total allocation for 200MW of generating capacity comprising two 100MW units = 2*40 = 80MW

2.15. The 60MW subtractor means an IR cost allocation for a single 200MW generating unit would be based on up to 140MW. However, the allocation for a

[6] The HVDC link has two ‘poles’ to transfer electricity between islands. If one pole trips off the system, the other pole can ramp up to provide some ‘self cover’, reducing the total transfer lost.

pair of 100MW generating units would be based on up to 80MW of their combined generation.

3. The issue

The current cost allocation methodology doesn’t include groups of generating units being modelled as CEs

3.1. Some groups of generating units are considered by the system operator to be a single CE due to the way they connect to the grid. Typically, this is because there is a single asset connecting the generation to the grid that comprises a single point of failure, whose loss the system operator considers a CE.

3.2. However, under the current methodology, the IR cost allocations for a group of generating units comprising a single CE risk is determined by the size of the individual generating units, not their combined risk to the power system.

3.3. For example, each turbine on a wind farm has historically been considered a generating unit for cost allocation purposes. But no individual wind turbine is large enough to generate 60MW. This means that, for example, a 200MW wind farm comprised of 50 4MW turbines would not be allocated a portion of the IR cost allocation, even if it was categorised as a CE risk because all 50 units shared a single point of connection to the grid.

3.4. This means not all parties who represent the same sized CE risk are paying the same share of IR costs. This limits the incentives on some generators to make operating and investment decisions that support power system resilience and reduce IR procurement costs.

3.5. Therefore, the IR cost allocation methodology does not fully meet its intent - to incentivise actions that reduce IR costs, while maintaining a level playing field between different generation technologies and configurations.

Why the Authority is addressing this issue now

3.1. The system operator currently classifies six wind, two geothermal, and two thermal generating stations (groups of generating units) with capacity greater than 60MW as CE risks. None of these stations, however, receive any allocation of IR costs because they do not include any units with capacity above 60MW.

3.2. We expect the number of stations like this to increase quickly in the future as more large groups of generating units, such as solar and wind farms, are added to the power system.

3.3. Maintaining the current cost allocation methodology would result in these assets not receiving IR cost allocations. This is despite them likely being classified as CE risks and so requiring IR cover. This would also apply to new groups of generating units if they were similarly configured.

3.4. For its 2025 credible event review, the system operator will investigate whether any shared protection schemes for inverter-based generation or shared inverter controls would result in further existing and future groups of generating units being considered CEs. Depending on the outcome of the review, this may result in more inverter-based generation classified as CEs due to shared settings and controls.

3.5. This means, without changing the current cost allocation method, the total cost of procuring IR will be shared across an even smaller proportion of generation that contributes to CE risks.

3.6. The Authority's recent investment pipeline survey indicates a significant increase in large-scale wind and solar generation coming online in the future. For example, our investment survey estimates:[7]

(a) Committed generation projects amount to almost 5,000GWh annual output, approximately 50% of which is intermittent generation (IG).

(b) The projected need for new generation by 2027 is 2,700GWh of annual output, above that already committed.

(c) Actively pursued projects that could be completed by 2027 have a combined annual output of over 22,000GWh. Solar projects account for 63% by output.

(d) Actively pursued projects that could be completed after 2027 have a combined annual output of over 38,000GWh. About three-quarters of these projects (by output) are offshore wind.

3.7. We also understand BESS is being considered as a likely complement to IG, particularly solar generation.[8]

3.8. We consider addressing this issue would incentivise new generators to configure their assets in a way that requires less IR procurement and would promote efficient investments in flexible capacity to balance variable renewable generation.

3.9. This would reduce costs to consumers through a lower total cost of producing electricity and ensure consumers' electricity supply continues to be reliable as New Zealand transitions to a highly renewable power system.

Q1. Do you agree with the description of the issues identified by the Authority? If not, why not?

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7 See PowerPoint Presentation (ea.govt.nz)

8 For example, it has been reported that Helios intends to invest in BESS to accompany its 300MW solar farm, while Lightyears Solar has also indicated (here and at 2:30 here) that it is likely to include BESS alongside its solar farms in 2025.

4. Regulatory statement for the proposed amendment

Objectives and outline of the proposed amendment

4.1. The key objectives of our proposed amendment are:

(a) to clarify the Code to better reflect the intent of a causer pays methodology for IR cost allocation

(b) for IR cost allocation to adapt to who is causing IR procurement and by how much

(c) to allow for a timely change that is targeted at the immediate issues.

4.2. We propose requiring groups of generating units that comprise a single CE risk to receive the same IR cost allocation as single generating units posing the same CE risk.

4.3. Allocations would also be restricted to generating units, or groups of generating units that are:

(a) located at a single point of connection to the grid

(b) treated as CEs under normal operating conditions

(c) not a subset of a group of generating units that also receives an allocation.

4.4. The amendment also introduces administrative clauses to ensure the system operator has the generation information necessary for calculating allocations, and to provide transparency in what generation would be allocated IR costs.

4.5. Further details of each component of the amendment and their rationales (including how they meet the objectives of our amendment) are described in Appendix A. The draft Code amendment is provided as Appendix B.

4.6. We are seeking to address the immediate cost allocation issues in a timely manner with minimal disruption to service provider tools and processes. This will ensure participants receive early clarity and a timely change to their likely IR cost allocation, supporting efficient investment.

4.7. In particular, we consider the following two items are out of scope at this time:

(a) Extending allocations to causers of IR procured for ECE risks. CEs are not the only causers of the need for IR, because IR are also sometimes procured for ECEs. However, IR are primarily procured for CE risks. Historically only CE risks have received IR cost allocations. The objective of this proposal is limited to ensuring a more complete set of CE risk causers receive allocations.

(b) Changing the method for allocating the share of IR costs based on the level of generation that is treated as a CE risk. Currently this is achieved by proportionally allocating a share of the total IR cost according to the quantity of generation above 60MW (ie. applying the '60MW subtractor'). We acknowledge this is imperfect, but note that investigating changes to this mechanism would require significant time and effort.

For IR cost allocation, we consider it is more important to address the immediate issue at hand. For the purposes of this proposal, it is sufficient that there is some mechanism to incentivise investment in lower risk plant configurations. Given this mechanism, this proposal would result in these incentives applying to more of the causers of IR costs based on the risk they pose.

4.8. Further work to enhance the cost allocation methodology (including for those aspects mentioned above) will be subject to prioritisation of the Authority's longer-term work plan. In the interim, we intend to monitor the effectiveness of these proposed amendments, should they be made, and will consider accelerating this further work should we not see the expected benefits.

Q2. Do you agree with the objectives of the proposed amendment? If not, why not?

The proposed amendment's benefits are expected to outweigh the costs

4.9. The Authority considers the proposed amendment would provide long-term benefits to consumers by furthering all three limbs of our statutory objective – competition, reliability, and efficiency.

4.10. Overall, this proposal would mean more of the causers of IR procurement would pay a share of the costs based on the risk they pose to the power system. This would better reflect the intent of incentivising actions that reduce IR costs while maintaining a level playing field between different generation technologies and configurations.

4.11. By aligning IR cost allocations to the system operator's determination of CEs, allocations would automatically adapt to who is causing IR procurement and by how much. This would reduce the risk of future changes in generation technology and configuration resulting in generation that requires IR cover avoiding an appropriate IR cost allocation. More detail on these benefits, along with the costs associated with the amendment, are outlined below.

4.12. The benefits occur through market incentives altered by changes to IR cost allocations under this proposed amendment, as discussed below. To provide context for these benefits, we have performed market impact assessments to demonstrate potential changes in IR cost allocations to existing and future generation. The market impact assessments are described in Appendix C.

Competition benefits

4.13. This proposal promotes competition by incentivising investments in the most efficient mix of technologies.

4.14. Without this proposed amendment, some technologies (eg. wind farms, solar farms and BESS) would generally not be subject to an appropriate share of the operating IR procurement costs relative to other generation technologies of an equivalent size.

4.15. This would result in a disproportionate level of IR costs being applied to other generating technologies, potentially impacting the business cases for investing in larger geothermal units or enhancing the efficiency and capacity of existing hydro generators.

4.16. These proposed amendments therefore help to incentivise efficient investment in these generation technologies.

4.17. Despite improved incentives to invest in alternative technologies like larger geothermal units or existing hydro generation, we do not consider the impact of this proposed amendment on IG would be large enough to prevent extensive investment in this type of generation in the short to medium term.

4.18. Instead, it may help ensure a more efficient mix of renewable generation technologies and IR provision in the longer term as New Zealand electrifies its economy.

4.19. Under this proposed amendment, we do not consider the incentives to invest in BESS would be reduced overall despite receiving new IR cost allocations.

4.20. Much of the upcoming generation investment is likely to be IG, with BESS considered by prospective investors as a likely complement to IG, particularly solar generation (as discussed in paragraph 3.1).[9]

4.21. These amendments may further incentivise investment in BESS to accompany IG within a generator's portfolio. Unlike BESS, the unpredictable nature of IG would result in new unpredictable IR cost allocations that cannot be offset by providing a share of IR (as IG cannot provide IR). BESS can provide IR to cover both its own cost allocation and that of IG, given it can generally provide twice its generation capacity as IR while charging (though we note this may be subject to network constraints).[10]

4.22. By incentivising hydro, demand response, and BESS, our amendments promote investment in flexible capacity.

4.23. Investment in flexible capacity will help efficiently and reliably support New Zealand's transition to a high renewable energy-based economy. This is because flexible resource:

(a) is required to balance the fluctuating energy provided by IG

(b) is required for providing ancillary services

(c) can provide services to accommodate the increasing capacity and stability needs of transmission and distribution networks as the economy electrifies.

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12 For example, BESS would be able to store the energy produce by solar generation in the middle of the day and release the energy back into the system during evening or morning peaks when wholesale electricity prices are at their highest.

10 BESS can generally provide around double its generation capacity as IR while charging. It is able to provide both its capacity to reduce charging (as Interruptible Load), as well as its capacity to discharge (as generation IR). This, however, is subject to network constraints that may restrict its charge rate and therefore the amount of interruptible load it can offer.

Reliability and efficiency benefits

4.24. This proposal promotes reliability and efficiency benefits through incentivising reduction or removal of IR risks, and therefore IR procurement costs.

4.25. Extending allocation of IR costs to groups of generating units, particularly wind farms, solar farms and BESS, could incentivise their owners to build their plant differently and, as a result, reduce IR procurement and enhance system security.

4.26. For example, to avoid the group of units being classified as a CE, participants could invest in more than one connection line. Alternatively, where possible, they may be incentivised to build more smaller groups of generating units rather than fewer bigger groups because this would result in a lower IR cost allocation (as discussed in paragraph 2.11).

4.27. If this results in the largest system risk becoming smaller at any time, these choices would reduce the amount of IR the system operator needs to procure, leading to greater reliability and lower system costs (efficiency).

4.28. This proposed amendment would also encourage generators to offer their spare capacity from flexible resource as IR to offset their allocation of IR costs from IG. This additional IR could come from existing generation, or new investments in Interruptible Load (IL) or BESS (as mentioned above in paragraph 4.20). With more IR offered into the market, the cost of procuring IR is likely to fall. The cost of energy may also fall due to the co-optimisation of energy and IR.

4.29. This proposed amendment may also promote reliable supply during demand peaks. This could occur either through increased flexibility to replace IG during times of low wind or low sunshine, or through reduced IR requirements lowering the total supply capacity required to meet energy and IR demand.

Costs

4.30. The costs to implement this proposal include approximately $180,000 for updating the system operator’s and clearing manager’s tools and processes.

4.31. It is also possible these amendments result in some disbenefits, although we consider this unlikely overall, as discussed in the following paragraphs.

4.32. As discussed in paragraph 2.11, the 60MW subtractor ensures, for plant subject to allocations based on the risk they pose, investors are incentivised to build a given amount of generation capacity using a larger number of lower risk plant, rather than fewer higher risk plant. This similarly affects incentives for plant exiting the market.

4.33. As discussed in paragraph 4.6(b), we recognise the 60MW subtractor is an imperfect mechanism of achieving this intent, but we do not propose changing this mechanism at this stage.

4.34. The incentives for larger generators have significant effect on efficient IR procurement, as the system operator procures IR to meet the largest generation risk at any given time. It is possible that the 60MW subtractor could mean large generators subject to allocations under the current methodology receive less than the efficient level of allocation.

4.35. If this was the case, this proposed amendment could result in an even less efficient allocation to those large plant that do or would receive allocations under the current methodology. This is because allocations to those plant would reduce with this amendment as a result of spreading the IR procurement costs across more generators.

4.36. The Authority, however, considers its proposal would improve incentives for groups of generating units as they currently receive no allocation for the risk they pose. As this applies to a large proportion of the expected generation investment in the near term, we are confident this proposal improves incentives for efficient investment in new plant overall.

4.37. We also consider it is unlikely this proposed amendment would affect generators' exit decisions. The changes in allocation of IR costs are likely to be immaterial compared to other factors affecting exit decisions. These factors include, for example, carbon costs, fuel supply, and age of plant.

4.38. We also consider this amendment is an enabler for any further improvements to the causer-pays methodology. This is because this amendment ensures most of the causers pay a share of IR costs. Further improvements to the methodology will be considered for prioritisation as part of the Authority's long-term work plan.

Costs versus benefits

4.39. As discussed above, we consider this proposal would:

(a) promote competition by levelling the playing field between different generation technologies and asset configurations. This would lead to more efficient generation investment decisions and therefore lower costs for consumers in the long term

(b) promote efficient operation by incentivising actions that result in lower IR costs, either because less IR need to be procured by the system operator, or because the amendment would encourage more IR to be offered into the market

(c) promote reliable supply during system peaks both through incentivising increased flexible capacity and reduced IR requirements (flexibility is enabled both through levelling the playing field and incentivising more IR to be offered, which can only be done with flexible plant).

4.40. Given these benefits and the relatively low costs to implement this proposed amendment, the Authority considers the benefits of this proposal exceed the costs.

Q3. Do you agree the benefits of the proposed amendment outweigh its costs?

Q4. Do you think there are any other costs or benefits for the proposed amendment that have not been identified?

The Authority has identified four other means for addressing the objectives

4.41. The Authority considered the following variations of this proposal that would result in a greater set of causers of CE risks paying a share of IR costs (as discussed in Table 2 at Appendix A):

(a) The Authority considered allocating costs to CE risks under all conditions (see restriction 1 in Table 2), instead of only creating allocations for risks classified as CE risks under normal operating conditions.

(b) The Authority considered applying a single 60MW subtractor to the total risk where a risk comprised one owner's generation across more than one point of connection (see restriction 2 in Table 2), instead of applying the 60MW subtractor to generation at each point of connection,

(c) The Authority considered sharing a single 60MW subtractor between the generation owners of a risk group comprising generation from more than one generation owner (see restriction 3 in Table 2), instead of applying the 60MW subtractor to each generator.

4.42. The Authority also considered amending the Code to specify the current reasons for the system operator classifying generation as a CE (under normal conditions). This would involve hard-coding the current classification of CE events so allocations would apply to generation meeting those conditions. This proposal, on the other hand, allows allocations to automatically update when the system operator updates its classification of a CE.

The proposed amendment is preferred to other options

4.43. The Authority has evaluated the other means for addressing the objectives and prefers its proposal. Specifically, this proposal better meets the following objectives:

(a) IR cost allocation being adaptable to changes in the causers of IR procurement and by how much they cause it and,

(b) allowing for a timely change that is targeted at the immediate issues.

4.44. The reasons for preferring this proposal over the three variations listed in paragraph 4.42 is we consider this proposal better allows for a timely change while being targeted to capture the majority of groups of generating units typically treated as CE risks. This is described further in Table 2 at Appendix A.

4.45. The Authority prefers this proposal to the option described in paragraph 4.43 of hard-coding the current reasons for the system operator's classification of CEs. This is because this proposal makes IR cost allocation adaptable to changes in CE classification and therefore changes in who is causing the need for reserve procurement and by how much.

4.46. This makes it clearer to participants that the Authority intends that IR cost allocations should be based on how much a participant causes the need for reserve procurement. In turn, this helps ensure they are incentivised to act in a way that results in an efficient level of reserve procurement.

Q5. Do you agree the proposed amendment is preferable to the other options? If you disagree, please explain your preferred option in terms consistent with the Authority's statutory objective in section 15 of the Electricity Industry Act 2010.

The proposed amendment complies with section 32(1) of the Act

4.47. The Authority's main objective under section 15(1) of the Act is to promote competition in, reliable supply by, and efficient operation of, the electricity industry for the long-term benefit of consumers. The Authority's additional objective under section 15(2) of the Act is to protect the interests of domestic and small business consumers in relation to their supply of electricity. The additional objective only applies to the Authority's activities in relation to the direct dealings between participants and these consumers.

4.48. Section 32(1) of the Act says the Code may contain any provisions that are consistent with the Authority's objectives and are necessary or desirable to promote any or all of the matters listed in section 32(1).

4.49. The Authority considers the proposed amendment is necessary or desirable to promote competition in the electricity industry, reliable supply of electricity to consumers, and efficient operation of the electricity industry. This is described in paragraph 1.2.

Q6. Do you agree the Authority's proposed amendment complies with section 32(1) of the Act?

The Authority has applied Code amendment principles

4.50. When considering amendments to the Code, in accordance with its Consultation Charter the Authority applies the following Code amendment principles:

Table 1: Code amendment principles

Principle	
Principle 1 – Clear case for regulation	The Authority will only consider amending the Code when there is a clear case to do so.
Principle 2 – Costs and benefits are summarised	The Authority is required to include with any Code amendment proposal an evaluation of the costs and benefits of the proposed amendment. The Authority will also include a summary of this evaluation
Principles 3 - 7	Not applicable. The Authority considers there is a clear best option in terms of a solution in this case.

Appendix A Details of each component of this proposed amendment and their rationales

A.1. This appendix provides details of each component of the proposed amendment and their rationales, including how the component meets the objectives of this amendment. To recap, the key objectives of this proposed amendment are:

(a) to clarify the Code to better reflect the intent of a causer-pays methodology for IR cost allocation

(b) for IR cost allocation to adapt to who is causing IR procurement and by how much

(c) to allow for a timely change that is targeted at the immediate issues.

A.2. This Appendix has been arranged into the following sections

(a) Causers of CE risks would be subject to allocations

(b) There would be restrictions to CE risks subject to allocations

(c) Each generating unit would receive only one allocation

(d) There would be administrative obligations.

Causers of CE risks would be subject to allocations

A.3. Clause 8.59 currently provides for allocations of availability costs to generators in respect of each generating unit, based on the quantity of injection in excess of 60MW.

A.4. The Authority proposes to amend the Code so instead of referring to generating units, Clause 8.59 would refer to a generating unit or group of generating units that appears in a list of 'at-risk generation'.

A.5. The list of at-risk generation would include generating units or groups of generating units owned by a single generator whose failure, or failure of assets connecting it or them to the grid, would be treated by the system operator as a single CE.

A.6. This is designed to reflect the causer-pays methodology for IR cost allocation. It does this by requiring the owners of generation treated as a CE risk to be allocated a share of IR costs based on the risk they pose, if they would be the causers of the CE. In the Authority's view, a generator should be considered the causer of any CE risk resulting from the loss of their connection assets, and therefore be allocated availability costs for that risk,. This is because generators are able to negotiate the level of redundancy in these assets with the grid owner.

A.7. By tying allocations to the system operator's classification of CEs, the amendment also meets the objective for IR cost allocation to adapt to who is causing IR procurement and by how much.

There would be restrictions to CE risks subject to allocations

A.8. The list of at-risk generation, however, would be subject to some restrictions on which CE groups of generating units are included under this proposed amendment. The restrictions and their rationales are shown in Table 2 below.

Table 2: Restrictions to CE risk allocations under proposed amendment

Restriction		Rationale
1	Under this proposal, the list of at-risk generation would only include generating units or groups of generating units comprising a CE under normal operating conditions. Specifically, this excludes generation that is only a CE during commissioning or outages of grid assets.	This is required to meet the Authority's objective of a timely and targeted change. Allocating costs to generators for the CE risk they pose under all conditions would require significant changes to the tools of the system operator and clearing manger, as well as greater information provision requirements on generators.
2	Under this proposal, the list of at-risk generation would only include generating units or groups of generating units at a single point of connection. This means where a single CE risk includes generating units located at more than one point of connection, the generation at each point of connection would be treated as its own entry on the list. This in turn would result in the 60MW subtractor applying to the relevant generation at each point of connection.	In our view, it would be more consistent with the causer-pays methodology if the generator was allocated availability costs based on the total CE risk it posed, with the 60MW subtractor only applied to its total generation, where the risk crosses more than one point of connection. This is because the generator would be allocated the same availability costs as another generator posing the same sized risk whose generating units connected at a single point of connection. Creating allocations this way would, however, require additional changes to the system operator's and clearing manager's tools and processes. We also consider CE risks including generation at more than one point of connection are uncommon and therefore the potential benefit of accommodating this use case is limited. We therefore prefer this proposal as it meets the Authority's objective of a timely and targeted change without sacrificing material benefits.
3	Under this proposal, the total allocations across generators for a CE risk that includes generation from more than one generator would not represent the total risk posed. In other words, the total allocation would not be the same as for the same sized risk posed by a single generator. This is because, under this proposal, the 60MW subtractor is applied separately for each generator, to the generator's contribution to the shared risk.	For the total allocations across generators to represent the total risk posed, the 60MW subtractor would need to be shared across generators based on their share of the total risk. While creating allocations this way would, in the Authority's view, be more consistent with the intent of cost allocation, it would require additional changes to the system operator's and clearing manager's tools and processes. We also consider CE risks comprising more than one generator are uncommon and

		therefore the potential benefit of accommodating this use case is limited. We therefore prefer this proposal as it meets the Authority's objective of timely and targeted change, without sacrificing material benefits.

Each generating unit would receive only one allocation

A.9. Under this proposal, a generating unit or group of generating units will contribute to, at most, one entry on the list of at-risk generation. Specifically, it would contribute only to the entry with the greatest total generating capacity. This means, for example, if a generator has two generating units comprising a single CE risk, then the generator would receive an allocation for the total generation of those two units and would not also receive separate allocations for the generation from the individual units.

A.10. Allocating to the greatest risk meets the intent of cost allocation to incentivise actions that result in reduced IR procurement. IR are only required to cover the greatest risk group a generating unit belongs to because, by covering that group, the smaller risks are also covered. An additional incentive created by allocating to a subset of this risk would only provide benefit through its impact on the larger set, ie. would not provide additional benefit to allocating to the larger set.

A.11. Allocating only to the largest set also allows consistency with the system operator's process of determining CEs. The system operator only needs to procure IR for the largest risk. Therefore, for the purpose of procuring IR, if it determines a certain set of generation to be a CE, then it does not need to determine if the subset is also a CE.

There would be administrative obligations

A.12. To ensure allocations can be calculated, the system operator would be able to request, and generators would be required to provide, the injection information necessary to calculate allocations under Clause 8.59.

A.13. Under the proposed amendment, the system operator would be required to maintain and publish the list of at-risk generation (including start and end dates where a particular generating unit or group of generating units will satisfy the criteria for inclusion for a limited time only). The system operator would also be required to specify in the policy statement the process for updating the list. These clauses are designed to ensure transparency around which generating units or groups of generating units would be subject to allocations and how these are identified.

A.14. The system operator would only be required to include a generating unit or group of generating units as an entry on the list where it has a total generating capacity of more than 60MW. Including items with generating capacity equal to or below 60MW would create an unnecessary burden on the system operator because such generation would not receive any allocation of availability costs. This is because their injections in a trading period would never exceed the 60MW subtractor.

Appendix B Proposed Code amendment

1.1 Interpretation

[…]

at risk generation means a **generating unit** or group of **generating units** as identified in the list of **at risk generation** maintained by the **system operator** in accordance with clause 8.59A

[…]

connection asset, for the purposes of Part 8, and subparts 2, 6 and 7 of Part 12, has the meaning set out in the **transmission pricing methodology**

[…]

8.59 Availability costs allocated to generators and HVDC owner

The **availability costs** in a **billing period** must be allocated separately to persons in the North Island and South Island in accordance with the following formula:

$$\text{Share}_t = \frac{Ac_t * m_t}{M_t}$$

where

Share_t	is the **availability cost** allocated to a **generator** who owns **at risk generation** ~~**generating unit**~~ x or to the **HVDC link** for **trading period** t for the North Island or South Island as appropriate
Ac_t	is the **availability cost** for the North Island or South Island as appropriate incurred in respect of **trading period** t
m_t	$\left\{\right.$ is $\max(0, INJ_{GENxt} - (h * INJ_D) - E^{IR}_{GENxt}) = m_{xt}$ for any **at risk generation** ~~**generating unit**~~ is $\max(0, HVDC_{Riskt} - (h * INJ_D) - E^{IR}_{HVDCt}) = m_{ht}$ for the **HVDC link**
M_t	is $\sum_x m_{xt} + m_{ht}$
h	is 0.5 **MWh/MW**
INJ_{GENxt}	is the **electricity injected** (expressed in **MWh)** by **at risk generation** ~~**generating unit**~~ x in **trading period** t into the North Island or South Island as appropriate
E^{IR}_{GENxt}	is the quantity of any **instantaneous reserve** provided under any **alternative ancillary service arrangements** for **instantaneous reserve** authorised by the **system operator** for **at risk generation** ~~**generating unit**~~ x in **trading period** t
$HVDC_{Riskt}$	is the **at risk HVDC transfer** (expressed in **MWh)** in **trading period** t

into the North Island or South Island as appropriate

E^{IR}_{HVDCt} is the quantity of any **instantaneous reserve** provided under any **alternative ancillary service arrangement** for **instantaneous reserve** authorised by the **system operator** for **at risk HVDC transfer** in **trading period** t

INJ_D is 60 **MW**.

8.59A At risk generation list

(1) The **system operator** must **publish** and maintain a list of **at risk generation** in accordance with this clause.

(2) The list must:

(a) list each **generating unit**, or group of **generating units** at a single **GIP** and owned by a single **generator**, whose failure, including the failure of the **connection assets** connecting it or them to the **grid**, would be treated as a contingent event (as defined in the **policy statement**) under normal conditions; and

(b) where a **generating unit** or group of **generating units** satisfies paragraph (a) for a limited time only, specify a start and end date and time for the inclusion of that **generating unit** or group of **generating units** in the list.

(3) Notwithstanding subclause (2):

(a) the list must exclude any **generating units** or groups of **generating units** which comprise a subset of any other group of **generating units** which meets the requirements of paragraph (a) (such that each **generating unit** is only included in one entry in the list); and

(b) each **generating unit** or group of **generating units** comprising an entry on the list must have a total generating capacity of more than 60 **MW**.

(4) The **system operator** must specify in the **policy statement** how it generates and updates the list.

(5) The **system operator** may request from any **participant** information about **electricity injected** where that information is required to calculate allocations of **availability costs** under clause 8.59, and specify a reasonable timeframe within which the information must be provided.

(6) A **participant** must comply with a request made under subclause (5) within the timeframe specified.

(7) For the purpose of this clause, normal conditions excludes times—

(a) when there is an outage of **grid** equipment; or

(b) during the **commissioning** of the relevant **generating unit** or group of **generating units**.

Q7. Do you have any comments on the drafting of the proposed amendment?

Appendix C Impact of proposed amendment on IR charges

Purpose

The Authority has performed indicative assessments of the impact this proposed amendment may have on IR charges to generators and the HVDC owner. These assessments are intended to:

- help the Authority understand the benefits of this proposed amendment; and
- help participants understand the potential impact of the cost allocation approach on their current operations and future investments.

These assessments provide context on potential incentives to prevent IR charges through:

- investing in technologies or asset configurations that present smaller CE risks; or
- increased offering of IR from pre-existing, or new investments in, flexible plant to offset uncertain IR charges for IG.

As discussed in paragraphs 4.14–4.30, the altered incentives under this proposed amendment lead to benefits through:

- improving competition in the electricity market; and
- reducing IR costs.

Summary

Our assessments estimate what might have happened if this proposed amendment had applied over the last three calendar years (the assessment period), adjusted for consistency with current scarcity pricing arrangements.

We have assessed the potential impacts on existing CE risks. This indicates charges that 10 existing generating stations would receive under this proposed amendment that they wouldn't have without it. It also indicates the reduction in IR charges this proposed amendment would cause for the 13 North Island CE risks that already receive IR charges.

We have also assessed the potential IR charges this proposed amendment would create for hypothetical large solar and wind farm CE risks that wouldn't receive IR charges under current arrangements.

These assessments are described further in the following sections and the results are shown in tables 3 and 4, figures 1 and 2.

The Authority's assessments are based on several assumptions and should be considered as indicative only. In particular, we have not attempted to model the impact that this proposed amendment or the existence of the hypothetical generators would have on market outcomes. Our modelling is described in the section 'Modelling approach, assumptions and limitations'.

IR charge impact for existing CEs

This assessment estimates the impact this proposed amendment would have had on IR charges for existing CE risks during the assessment period. It estimates charges for the 10 CE risk stations – (representing groups of generating units – that would receive charges under this proposed amendment, but do not under the current arrangements. It also estimates the reductions in charges this proposed amendment would cause for CE risks that already receive charges under the current arrangements.

Of existing generators, only those in the North Island would be affected because there are no current groups of generating units comprising a single CE risk in the South Island. For this reason, we only display results of this assessment for North Island generators.

The results are shown for each North Island CE risk, identified by market node. While a CE risk needn't ordinarily have a corresponding market node, each CE risk impacted by this proposed amendment does. The plant name, technology and generating capacity corresponding to each market node is shown in Table 6.

Analysis

This proposed amendment increases the number of CE risks receiving allocations in the North Island by 10, from 13 to 23. By sharing IR costs across more CE risks, this proposed amendment reduces allocations to CE risks already receiving allocations under the current arrangements.

We estimate that, under this proposed amendment, the CE risks that don't currently receive allocations (see Table 3) would together have been allocated 12.4% of total North Island IR costs over the assessment period.

Table 3, Table 4 and Figure 1 show our estimates of the impact on IR charges to each existing CE risk for each year of the assessment period, as well as annualised averages. Tables 3 and 4 show the underlying estimates of IR charges with and without this amendment. Table 3 shows the assessments for the station risks that would receive allocations under this proposed amendment, that do not currently. Table 4 shows the assessments for the unit risks and DC risk which already currently receive allocations.

Table 6 shows the generation technology and capacity for each of the CE risks. This provides context on potential impacts for prospective investors considering plant of similar size and technology in the North Island.

The indicative impacts are based on market outcomes including the level of generation from each generator during the assessment period, which may not be reflective of future conditions. For example, the Turitea wind farm was progressively commissioned between July 2021 and September 2023. The wind farm's annual charges, and corresponding impact on others' charges, should be interpreted with this in mind.

IR charge impact for hypothetical future generation

The case studies estimate charges over the assessment period under this amendment for hypothetical solar and wind farm CE risks.

We have performed eight case study assessments, representing hypothetical 150MW and 300MW capacity wind and solar farm CE risks in each island. These studies provide context on potential IR charges for future large wind and solar farm CE risks.

Under the system operator's current CE classification, a wind or solar farm would be considered a single CE risk where there is a single point of failure in assets connecting the generation to the grid. Charges to future wind and solar farms will be subject to the system operator's periodic review of the classification of contingent events.

The charges for each hypothetical wind and solar farm are based on estimates of the allocations to existing CE risks during the assessment period, under this amendment. We estimated these separately for each hypothetical generator, calculating allocations after adding the generator.

The generation information for the hypothetical generators is based on generation profiles from existing generators scaled to reflect the hypothetical generator’s different capacity.

Analysis

Table 5 and Figure 2 show our estimates of the impact on IR charges to each of the hypothetical solar and wind farm CE risks for each year of the assessment period, as well as annualised averages.

The indicative impacts are based on market outcomes during the assessment period, which may not be reflective of future conditions, including due to the impact of new large IG entering the market. Our assessments assume the hypothetical generation does not impact the availability costs.

Table 3: Impact of amendment on IR charges for existing CE risks – stations risks currently without allocation ($M)

Market node & plant name: station CE risks	Average annual impact	2021 impact	2022 impact	2023 impact	Average annual charges with amendment	Average annual charges without amendment	2021 charges with amendment	2021 charges without amendment	2022 charges with amendment	2022 charges without amendment	2023 charges with amendment	2023 charges without amendment
JRD1101 JRD0 Junction Road	$0.334	$0.482	$0.300	$0.220	$0.334	$0.000	$0.482	$0.000	$0.300	$0.000	$0.220	$0.000
LTN2201 TUR0 Turitea Wind Farm	$0.212	$0.021	$0.146	$0.471	$0.212	$0.000	$0.021	$0.000	$0.146	$0.000	$0.471	$0.000
MKE1101 MKE1 McKee	$0.210	$0.193	$0.212	$0.224	$0.210	$0.000	$0.193	$0.000	$0.212	$0.000	$0.224	$0.000
NAP2202 NTM0 Ngā Tamariki	$0.569	$0.598	$0.527	$0.583	$0.569	$0.000	$0.598	$0.000	$0.527	$0.000	$0.583	$0.000
TWC2201 TWF0 Tararua Wind Farm 3	$0.043	$0.060	$0.018	$0.051	$0.043	$0.000	$0.060	$0.000	$0.018	$0.000	$0.051	$0.000
WDV1101 TAP0 Te Āpiti	$0.021	$0.038	$0.015	$0.009	$0.021	$0.000	$0.038	$0.000	$0.015	$0.000	$0.009	$0.000
WKM2201 MOK0 Mokai	$0.742	$1.010	$0.660	$0.555	$0.742	$0.000	$1.010	$0.000	$0.660	$0.000	$0.555	$0.000
WVY1101 WPP0 Waipipi	$0.346	$0.406	$0.273	$0.358	$0.346	$0.000	$0.406	$0.000	$0.273	$0.000	$0.358	$0.000
WWD1102 WWD0 West Wind 1	$0.046	$0.005	$0.003	$0.130	$0.046	$0.000	$0.005	$0.000	$0.003	$0.000	$0.130	$0.000
WWD1103 WWD0 West Wind 2	$0.016	$0.015	$0.004	$0.030	$0.016	$0.000	$0.015	$0.000	$0.004	$0.000	$0.030	$0.000

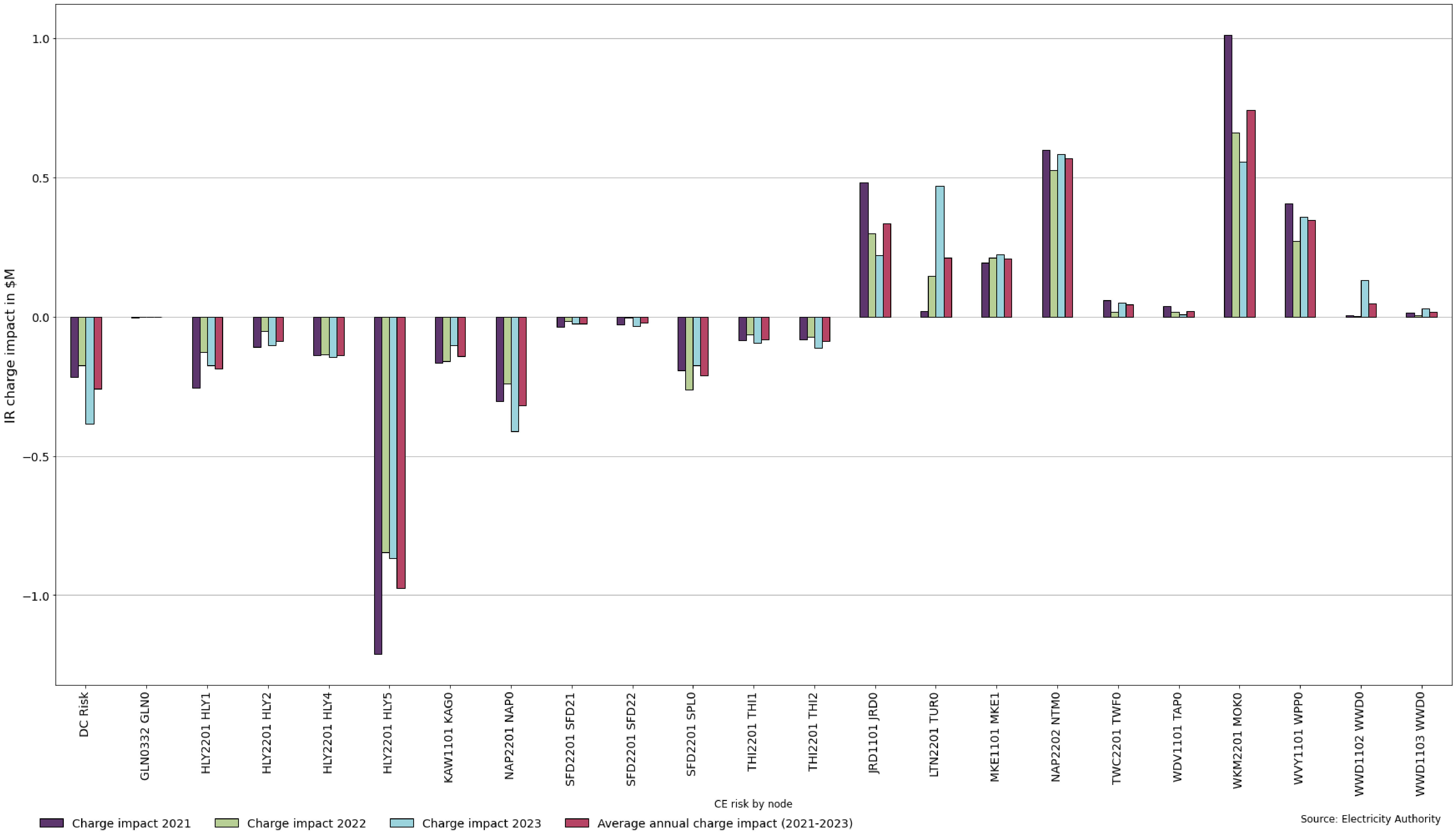
Table 4: Impact of amendment on IR charges for existing CE risks – unit and DC risks currently with allocations ($M)

Market node and plant name: unit & DC risks	Average annual impact	2021 impact	2022 impact	2023 impact	Average annual charges with amendment	Average annual charges without amendment	2021 charges with amendment	2021 charges without amendment	2022 charges with amendment	2022 charges without amendment	2023 charges with amendment	2023 charges without amendment
DC Risk HVDC	-$0.259	-$0.217	-$0.175	-$0.384	$2.275	$2.533	$2.453	$2.670	$1.845	$2.020	$2.526	$2.910
GLN0332 GLN0 Glenbrook Steel	-$0.002	-$0.004	-$0.002	$0.000	$0.017	$0.019	$0.031	$0.035	$0.019	$0.022	$0.001	$0.001
HLY2201 HLY1 Huntly Rankine 1	-$0.185	-$0.254	-$0.126	-$0.175	$1.375	$1.561	$1.828	$2.083	$1.232	$1.359	$1.065	$1.241
HLY2201 HLY2 Huntly Rankine 2	-$0.088	-$0.109	-$0.051	-$0.103	$0.633	$0.721	$0.929	$1.038	$0.472	$0.524	$0.498	$0.601
HLY2201 HLY4 Huntly Rankine 4	-$0.139	-$0.138	-$0.136	-$0.144	$1.043	$1.182	$1.138	$1.276	$1.214	$1.350	$0.778	$0.922
HLY2201 HLY5 Huntly 5	-$0.974	-$1.210	-$0.846	-$0.867	$6.789	$7.764	$8.869	$10.079	$6.422	$7.268	$5.077	$5.944
KAW1101 KAG0 Kawerau	-$0.142	-$0.164	-$0.159	-$0.102	$0.955	$1.097	$1.227	$1.391	$1.158	$1.318	$0.481	$0.583
NAP2201 NAP0 Ngā Awa Pūrua	-$0.319	-$0.304	-$0.242	-$0.411	$2.084	$2.403	$2.274	$2.578	$1.815	$2.057	$2.161	$2.573
SFD2201 SFD21 Stratford Peaker 1	-$0.026	-$0.036	-$0.016	-$0.025	$0.173	$0.199	$0.233	$0.269	$0.161	$0.177	$0.125	$0.150
SFD2201 SFD22 Stratford Peaker 2	-$0.023	-$0.028	-$0.005	-$0.035	$0.141	$0.164	$0.180	$0.208	$0.036	$0.041	$0.208	$0.244
SFD2201 SPL0 Taranaki Combined Cycle	-$0.210	-$0.194	-$0.261	-$0.175	$1.404	$1.614	$1.547	$1.741	$1.752	$2.013	$0.912	$1.087
THI2201 THI1 Te Mihi 1	-$0.081	-$0.085	-$0.063	-$0.095	$0.527	$0.608	$0.631	$0.716	$0.453	$0.515	$0.496	$0.592
THI2201 THI2 Te Mihi 2	-$0.088	-$0.081	-$0.072	-$0.113	$0.571	$0.659	$0.610	$0.691	$0.518	$0.590	$0.584	$0.697

Table 5: Impact of amendment on IR charges for hypothetical CE risks ($M)

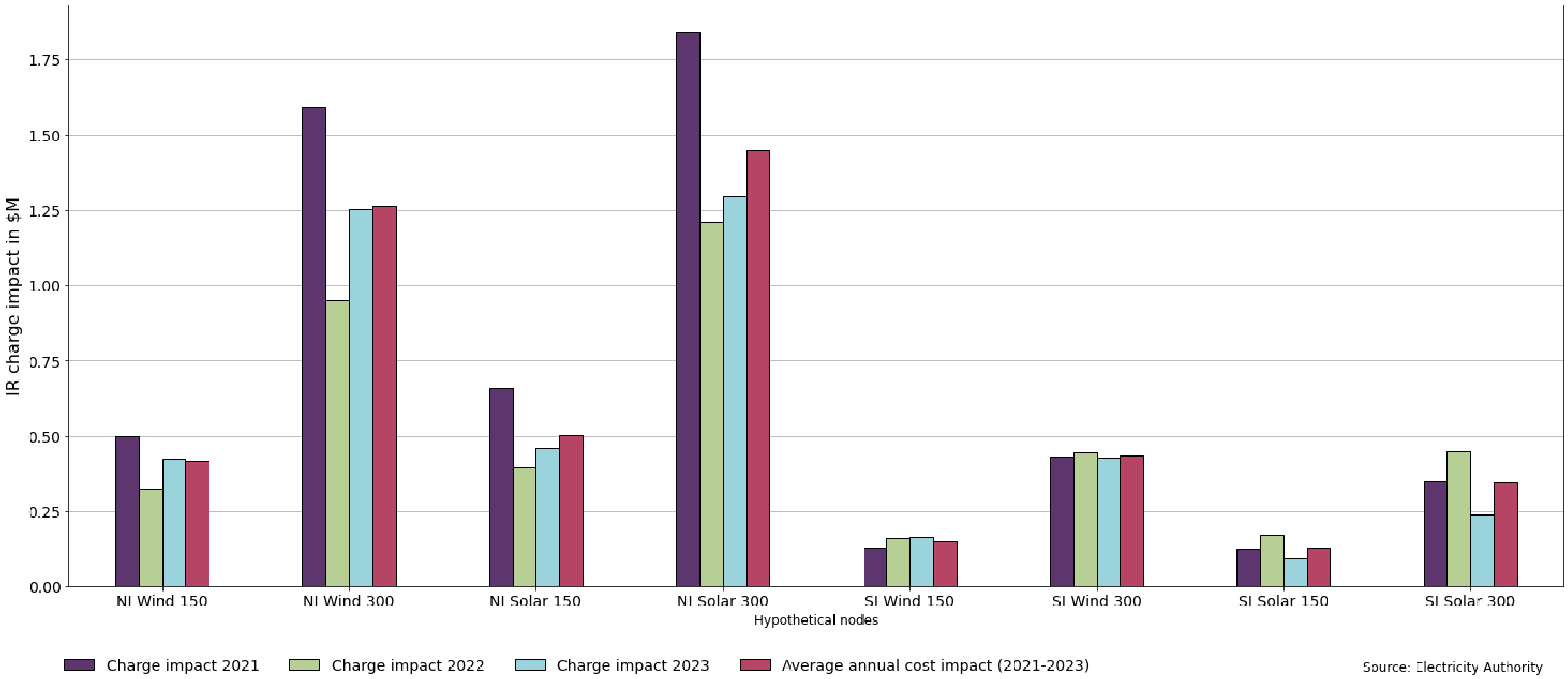
Hypothetical CE risks in the North Island (NI) and South Island (SI)	Average annual impact	2021 impact	2022 impact	2023 impact	Average annual charges with amendment	Average annual charges without amendment	2021 charges with amendment	2021 charges without amendment	2022 charges with amendment	2022 charges without amendment	2023 charges with amendment	2023 charges without amendment
NI Wind 150	$0.416	$0.499	$0.323	$0.426	$0.416	$0.000	$0.499	$0.000	$0.323	$0.000	$0.426	$0.000
NI Wind 300	$1.265	$1.592	$0.951	$1.253	$1.265	$0.000	$1.592	$0.000	$0.951	$0.000	$1.253	$0.000
NI Solar 150	$0.504	$0.658	$0.394	$0.459	$0.504	$0.000	$0.658	$0.000	$0.394	$0.000	$0.459	$0.000
NI Solar 300	$1.451	$1.842	$1.212	$1.298	$1.451	$0.000	$1.842	$0.000	$1.212	$0.000	$1.298	$0.000
SI Wind 150	$0.152	$0.129	$0.163	$0.164	$0.152	$0.000	$0.129	$0.000	$0.163	$0.000	$0.164	$0.000
SI Wind 300	$0.434	$0.430	$0.444	$0.427	$0.434	$0.000	$0.430	$0.000	$0.444	$0.000	$0.427	$0.000
SI Solar 150	$0.130	$0.126	$0.171	$0.092	$0.130	$0.000	$0.126	$0.000	$0.171	$0.000	$0.092	$0.000
SI Solar 300	$0.347	$0.351	$0.450	$0.240	$0.347	$0.000	$0.351	$0.000	$0.450	$0.000	$0.240	$0.000

Figure 1: Impact of amendment on IR charges for existing CE risks



Source: Electricity Authority

Figure 2: Impact of amendment on IR charges for hypothetical CE risks



Source: Electricity Authority

Table 6: Market node key

Station risk nodes	Plant Name	Technology	Capacity (MW)
JRD1101 JRD0	Junction Road	Thermal	130
LTN2201 TUR0	Turitea Wind Farm	Wind	222
MKE1101 MKE1	McKee	Thermal	100
NAP2202 NTM0	Ngā Tamariki	Geothermal	87
TWC2201 TWF0	Tararua Wind Farm 3	Wind	93
WDV1101 TAP0	Te Āpiti	Wind	90
WKM2201 MOK0	Mokai	Geothermal	112
WVY1101 WPP0	Waipipi	Wind	133
WWD1102 WWD0	West Wind 1	Wind	80
WWD1103 WWD0	West Wind 2	Wind	80
Unit & DC risk nodes			
DC Risk	HVDC	Transmission	0
GLN0332 GLN0	Glenbrook Steel	Co-generation	68
HLY2201 HLY1	Huntly Rankine 1	Thermal	250
HLY2201 HLY2	Huntly Rankine 2	Thermal	250
HLY2201 HLY4	Huntly Rankine 4	Thermal	250
HLY2201 HLY5	Huntly 5	Thermal	403
KAW1101 KAG0	Kawerau	Geothermal	109
NAP2201 NAP0	Ngā Awa Pūrua	Geothermal	144
SFD2201 SFD21	Stratford Peaker 1	Thermal	106
SFD2201 SFD22	Stratford Peaker 2	Thermal	106
SFD2201 SPL0	Taranaki Combined Cycle	Thermal	385
THI2201 THI1	Te Mihi 1	Geothermal	90
THI2201 THI2	Te Mihi 2	Geothermal	91

Modelling approach, assumptions, and limitations

Overview

To estimate IR charges, we first estimated the total availability costs to be allocated, and then the allocations for each generation CE risk and the HVDC risk. This estimation was carried out for each trading period and island during the assessment period.

For our assessment of impacts on existing CE risks, we needed to estimate IR charges both with and without the amendment. This is so we could determine impacts for existing CE risks whether or not they already receive allocations under the current arrangements. We only needed to do this for the North Island because the only existing CE risks impacted by this amendment are in the North Island.

For our case study assessments, we needed to estimate IR charges for both islands. We estimated these separately for each hypothetical generator, calculating allocations after adding the generator. To do this, we needed to estimate the hypothetical generators' injections.

We estimated trading period-level data by using averages of data from real-time dispatch (RTD) schedules produced by the system operator every five minutes. We then converted these to half-hourly values as appropriate to calculate IR charges for each half-hour trading period. For simplicity in the explanations below, we have only described our conversion from RTD values to half-hourly values where the method we used was not obvious.

Availability cost estimates

Our assessments are based on reasonable estimates of the availability costs (total IR costs) that the clearing manager would have used for each trading period and island during the assessment period, with adjustments to account for current scarcity pricing arrangements.

Our estimates of availability costs are based on, for each trading period and island, the averages of cleared IR quantities and prices (including for both fast instantaneous reserves and sustained instantaneous reserves) from RTD schedules produced by the system operator every five minutes. By comparison, the availability costs allocated by the clearing manager are based on time-weighted average dispatch quantities and final IR spot prices.[11] The availability cost used by the clearing manager also accounts for dispensation costs and constrained on costs, these costs are not considered in our analysis.[12]

We adjusted fast instantaneous reserve and sustained instantaneous reserve prices to cap them at the first scarcity price tranche for each. We did this to better reflect current pricing arrangements, noting there were several prices in the data set that far exceeded what would occur under current arrangements, including due to infeasible prices.

We have not attempted to adjust availability costs for the impact that this amendment or the existence of the case study generators may have had on market outcomes. In particular, this assumes no impact on IR prices and the size of the largest risk, which determines the quantity of IR procured.

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11 Prior to the Authority's real-time pricing project (RTP), final prices were determined using the final pricing schedule that was based off half-hour rather than five-minute metering data. Following implementation of RTP, final prices are based on a time-weighted average of dispatches, noting the system operator does not dispatch off of every five minute RTD.

12 See definition of availability costs in Part 1 of the Code.

Allocation estimates

Estimating allocations required estimates of injection data for generation and 'at-risk HVDC transfer', to perform the calculation in clause 8.59 of the Code.

The injection data we used for determining allocations to generators is specified below, along with how it differs from that used by the clearing manager:

- In our models, we estimated generation for each market node based on the average of cleared energy values within the given trading period, and then converted to generating unit level data where necessary, as described below. The generating unit level data used by the clearing manager, on the other hand, is provided by participants directly to Transpower, who then passes it on to the clearing manager.
- For existing South Island market nodes, we have estimated the unit level generation data. This is because the South Island generating units receiving allocations are offered as part of a station (and so the market node represents the station). To convert from station to generating unit data, we have assumed the number of units running is the minimum number required to produce the amount of generation seen at the market node, based on the rated capacity of the generating units. We have then assumed the generation is shared evenly across that number of units.

To estimate the 'at-risk HVDC transfer' for each trading period required data for HVDC injections into each island, as well as data on when the HVDC was and was not in bipole configuration.[13] This is because the at risk HVDC transfer under the Code equals:

- when the HVDC is in bipole configuration, the injections from the HVDC minus a hard-coded value representing the pole 2 overload, which differs per island,
- otherwise, the injections from the HVDC.

We have estimated the at-risk HVDC transfer for each RTD and then averaged these across the trading period. For each RTD, we have assumed the HVDC was in bipole configuration when the 'risk subtractor' from the RTD schedule results was greater than zero, and assumed the HVDC was otherwise not in bipole configuration. We then used the HVDC injection data from the RTD and applied the value in the Code representing the HVDC pole 2 overload where we determined the HVDC was in bipole configuration.

We have not attempted to adjust allocations for the impact this amendment or the existence of the case study generators may have had on market outcomes.

The hypothetical generators have been added to the generation being considered for an IR cost allocation over the time period analysed. While this would result in a reduction in the total IR allocation to each generator, it provides an indication of the relative share of the overall IR cost that they would be allocated. A more detailed analysis would require assumptions to be made as to which generators were displaced by the hypothetical generators and how trading behaviour of the displaced generators would likely change. These uncertainties would result in no greater accuracy in the absolute share of the IR cost allocation and likely have marginal impact on the proportional share of costs.

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[13] See definition of 'at-risk HVDC transfer' in Part 1 of the Code.

Case study generation profiles

To determine allocations for our case studies we needed to estimate injection information for each of the hypothetical generators for each trading period.

These estimates were based on profiles of existing generation as follows:

- For solar farms, we used the generation distribution of the Kaikohe solar farm from its commissioning date in February 2024 through to May 2024. This was then scaled up to 150MW or 300MW capacity as applicable. We note there will be some seasonal variation, but we have not attempted to quantify this effect. We chose this generator as it is the solar farm that has been offered into the market for the longest time.
- For wind farms, we used the generation distribution of Waipipi wind farms over calendar year 2023 and scaled up to 150MW or 300MW capacity as applicable. We chose Waipipi as it is the largest windfarm with 12 months of data at full availability.

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Appendix D Format for submissions

Submitter	

Questions	Comments
Q1. Do you agree with the description of the issues identified by the Authority? If not, why not??	
Q.2 Do you agree with the objectives of the proposed amendment? If not, why not?	
Q3. Do you agree the benefits of the proposed amendment outweigh its costs?	
Q4. Do you think there are any other costs or benefits for the proposed amendment that have not been identified?	
Q5. Do you agree the proposed amendment is preferable to the other options? If you disagree, please explain your preferred option in terms consistent with the Authority's statutory objective in section 15 of the Electricity Industry Act 2010.	
Q6. Do you agree the Authority's proposed amendment complies with section 32(1) of the Act?	
Q7. Do you have any comments on the drafting of the proposed amendment?	