



Generation Fault Ride Through

Decision Paper

August 2016

Introduction

- 1 The Electricity Authority (Authority) is an independent Crown entity responsible for promoting competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers.¹
- 2 In February 2011, the Authority consulted on a proposal to include generation fault ride through standards in the Electricity Industry Participation Code (Code).² The Authority consulted a second time on the proposal in August 2015.³
- 3 This paper sets out the Authority's decision to include generation fault ride through standards in the Code and gives reasons for the decision.
- 4 The new generation fault ride through standards require generating units that are not disconnected directly by protection systems to remain connected during transmission system faults. To maintain a secure and reliable power system, which promotes the Authority's statutory objective it is important that non-faulted generating units⁴ remain connected during periods of voltage disturbance during and immediately following transmission faults.
- 5 More information about the generation fault ride through project is available from the Authority's website at: <http://www.ea.govt.nz/development/work-programme/wholesale/fault-ride-through-project/>.

Decision

- 6 The Authority has decided to amend the *asset owner performance obligations and technical standards concerning voltage* section of part 8 of the Code to include fault ride through standards for generating units. The key elements of the standards are:
 - (a) generators connected to a network must ensure their assets remain stable and connected within defined over and under voltage no-trip zones during and immediately after a.c. transmission faults
 - (b) generators must ensure their assets remain stable and connected within a defined over voltage no-trip zone during and immediately after faults on the high voltage direct current (HVDC) link

¹ This is the Authority's statutory objective. Refer to section 15 of the Electricity Industry Act 2010.

² <http://www.ea.govt.nz/development/work-programme/wholesale/fault-ride-through-project/consultation/#c13918>

³ <http://www.ea.govt.nz/development/work-programme/wholesale/fault-ride-through-project/consultation/#c15508>

⁴ Generating units that are not disconnected by protection systems as the result of a transmission fault.

- (c) generators must ensure their assets generate reactive current to oppose changes in voltage that occur during and immediately after a.c. transmission faults.
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How the Authority made its decision

- 7 The objective of the Code amendment is to specify dynamic voltage performance obligations for all generation connected to the New Zealand grid. The obligations are expressed in the form of generation fault ride through envelopes intended to address the increasing risk of cascade failure during and immediately after transmission faults.
- 8 The Authority consulted on its proposal to amend the Code to include generation fault ride through standards in February 2011. The Authority received submissions from 12 parties including generating/retailer companies, the New Zealand Wind Energy Association (NZWEA) and Transpower:
 - (a) Six submitters supported the Authority's overall objective to address the increasing system stability risks during and immediately after transmission faults as new forms of generation are added to the system.
 - (b) Meridian, NZWEA, Todd, and Transpower agreed that a fault ride through standard is required. Trustpower and Windflow provided qualified support.
 - (c) Transpower raised a concern about over voltages in the lower North Island and a region around Benmore. The grid owner identified that known HVDC events involving Pole 3 would create over voltages in these areas more onerous than those assessed for the proposed fault ride through standards. In Transpower's view, a more stringent fault ride through standard than the one proposed should be applied in these regions.
- 9 The issue raised by Transpower required further system study work by Transpower that could not be carried out until resources committed to the HVDC Pole 3 project were released. After Transpower completed the system study work, the Authority published a second consultation paper in August 2015. Eight parties submitted on the second consultation paper:
 - (a) Contact, Genesis, Meridian, Mighty River Power and Nova supported the Authority's objective to address the increasing risk of cascade failure by adding fault ride through obligations to the Code. Only Trustpower did not agree with the Authority's objective.
 - (b) Meridian and Trustpower did not support the Authority's proposed fault ride through standards. Their concerns are discussed below in paragraphs 34 to 70 below.
- 10 Parties that made submissions on the consultation documents are listed in Table 1.
- 11 All submissions and a summary of submissions can be found on the Authority's website at:
 - (a) <http://www.ea.govt.nz/development/work-programme/wholesale/fault-ride-through-project/consultation/#c15508> (consultation paper 1)
 - (b) <http://www.ea.govt.nz/development/work-programme/wholesale/fault-ride-through-project/consultation/#c15508> (consultation paper 2).

Table 1 List of submitters

Submitter	Category
February 2011 Consultation	
Contact	Generating company and retailer
Genesis	Generating company and retailer
Major Energy Users Group (MEUG)	Major consumers
Meridian	Generating company and retailer
NZ Wind Energy Association (NZWEA)	Wind generation representative body
Philip Wong Too	Individual
Repower Australia Pty Ltd	Wind turbine manufacturer
Todd Energy	Generating company and Retailer
Transpower	Grid owner and system operator
Trustpower	Generating company and retailer
Vestas NZ Wind Technology Ltd	Wind turbine manufacturer
Windflow Technology Ltd	Wind turbine manufacturer
August 2015 Consultation	
Contact	Generating company and retailer
Genesis	Generating company and retailer
Meridian	Generating company and retailer
Mighty River Power	Generating company and retailer
Nova Energy	Retailer
NZWEA	Wind generation association
Transpower	Grid owner and system operator
Trustpower	Generating company and retailer

Why the Authority made this decision

- 12 The generation mix is changing as non-synchronous generation, eg wind farms and small scale distributed generation, is connecting in increasing quantities. The Authority is concerned that the current obligations for generators to ride through transient voltage disturbances and remain connected are inadequate. If they are not improved, the Authority's statutory objective may not be furthered because:
- (a) Productive efficiency would be adversely affected by higher quantities of instantaneous reserve having to be purchased to protect against the loss of injection from non-faulted generating plant
 - (b) productive efficiency and reliability would be adversely affected by restrictions potentially being placed on the types of generation development in some geographical regions
 - (c) reliability would be adversely affected by consumers facing higher risk of disconnection due to gradual erosion of system stability.

The amendment promotes reliability and efficiency but has no effect on competition

- 13 After considering all submissions on the Code amendment proposal, the Authority believes that the final Code amendment will deliver long-term benefits to consumers by:
- (a) contributing to the reliable supply of electricity to consumers by reducing the risk of consumers losing supply as a result of generation disconnecting from the grid during grid faults
 - (b) improving the efficient operation of the electricity industry by reducing the quantity of instantaneous reserve required to protect against loss of injection from disconnected generation.
- 14 The reliability and efficiency benefits of the Code amendment are not interdependent and consequently there are no trade-offs between these two limbs of the Authority's statutory objective.
- 15 The Authority does not expect the Code amendment to have a material effect on competition in the electricity industry.

The proposal's benefits are greater than its costs

- 16 The Authority has assessed the economic benefits and costs of the amendment and expects it to deliver a net economic benefit.

Benefits

- 17 The primary benefit of the proposed fault ride through standards arises from the avoided cost of purchasing additional instantaneous reserve. If the fault ride through standards were not introduced, additional costs would arise over time because the system operator would be required to purchase increased quantities of instantaneous reserve. Consumers would face a productive inefficiency from the time that the total output of wind generation became the contingent event risk and determined the quantity of instantaneous reserve required on the power system.
- 18 The Authority's assessment of benefits made allowance for the reduced level of instantaneous reserve required once the national market for instantaneous begins operating from November 2016.
- 19 The proposed fault ride through standards have a secondary benefit in preventing the gradual deterioration in the security of the power system. In the absence of fault ride through standards, there is an increasing risk of consumer disconnection as a result of sympathetic tripping of non-faulted generating units during transmission faults.

Costs

- 20 The costs associated with the proposed fault ride through standard arise from additional costs incurred by generating companies in meeting the proposed fault ride through standards. The costs are associated with improved capability of voltage and reactive power control equipment in generating assets.
- 21 The Authority's assessment of costs (and benefits) used a wind generation penetration scenario approach. The three scenarios selected are shown in Figures A.1, A.2 and A.3 in Appendix A, and were derived from the scenarios originally developed by the wind generation investigation project. The Authority updated the project's scenarios to take into account slower rates of wind penetration than originally predicted.

Other input assumptions

22 The other input assumptions used in the cost-benefit assessment are set out in tables below.

Table 2: Input assumptions used to calculate costs

Input Assumptions for Costs	North Island	South Island
2015 base year installed wind generation capacity	688 MW	112 MW
Wind generation capacity factor	41%	41%
Average national contingent event risk excluding wind	350 MW	
Wind turbine total installed cost per MW	\$3 m	\$3 m
Increase in turbine cost to meet fault ride through standard	1.25%	1.25%

Table 3: Input assumptions used to calculate benefits

Input Assumptions for Benefits	North Island	South Island
Fast instantaneous reserve (FIR) required to cover 1 MW of wind turbine risk as a national contingent event (CE) risk	Both Islands	
	0.9 MW	
Sustained instantaneous reserve (SIR) required to cover 1 MW of wind turbine risk as a national CE risk	Both Islands	
	1 MW	
FIR required to cover 1 MW of wind turbine risk as additional HVDC extended contingent event (ECE) risk	0.8 MW	0.8 MW
SIR required to cover 1 MW of wind turbine risk as an additional HVDC ECE risk	1 MW	1 MW
Average cost of FIR per MWh procured nationally for CE risk	Both Islands	
	\$2.18	
Average cost of SIR per MWh procured nationally for CE risk	Both Islands	
	\$1.74	
Average cost of FIR per MWh procured when the HVDC ECE is binding	\$8.28	\$3.30
Average cost of SIR procured when the HVDC ECE is binding	\$1.19	\$1.55

Input Assumptions for Benefits	North Island	South Island
Percentage of trading periods when HVDC ECE is binding for north transfer	3.3%	-
Percentage of trading periods when HVDC ECE is binding for south transfer	-	0.4%

Table 4: Discounted cash flow parameters

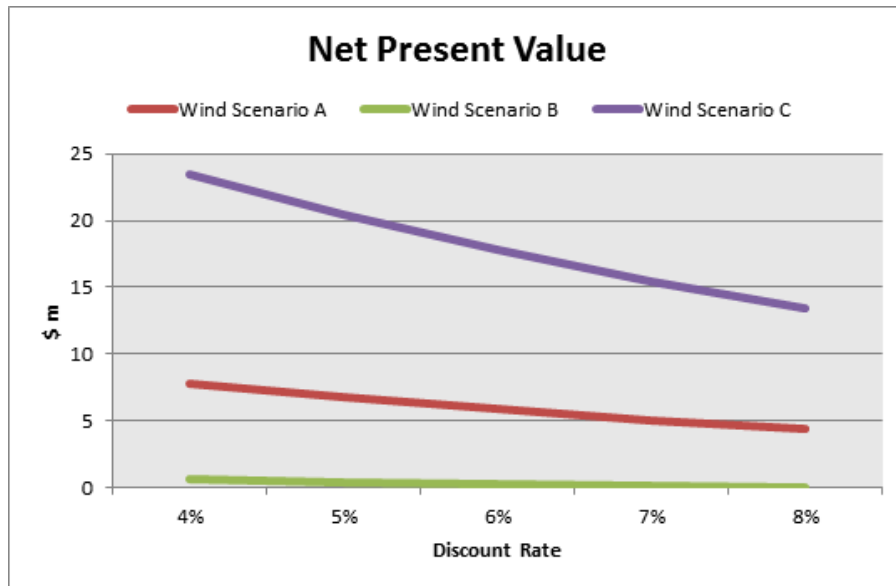
Discounted Cash Flow	Parameter
Discount rate sensitivity	4% - 8%
Discount period	15 years

- 23 Increased wind turbine costs were calculated as 1.25% of installed capital costs and are assumed to ramp down to 0% over 10 years. The basis of this assumption is that compliance costs will decline over time as fault ride through technology becomes a standard feature of grid connected wind turbines.
- 24 HVDC link faults impose over voltages simultaneously in both islands, risking wind generation close to Haywards and Benmore. When a trip of the HVDC bipole occurs, reserve cannot be transferred from one island to the other in a national market for instantaneous reserve. As a result, wind generation close to Haywards must be covered for HVDC faults by instantaneous reserve sourced in the North Island. Similarly, wind generation close to Benmore must be covered for HVDC faults by instantaneous reserve sourced in the South Island.
- 25 Because a.c. faults impose under voltages in the faulted island only, they do not cause loss of wind generation in the non-faulted island. It is assumed that the loss of wind generation for a.c. faults can be covered by instantaneous reserve sourced nationally.
- 26 The cost-benefit analysis considered the quantity of instantaneous reserve required to cover:
 - (a) the loss of wind generation for either North Island a.c. faults or South Island a.c. faults, whichever quantity is greater, plus
 - (b) the loss of wind generation for HVDC faults.
- 27 Instantaneous reserve costs for HVDC faults arise only when the HVDC ECE risk is binding and must be purchased separately in each island. The costs are estimated by taking the percentage of trading periods when the HVDC ECE risk was found to be binding in 2014. No allowance has been made for the effect that increasing levels of wind generation have on the number of binding trading periods.
- 28 Purchasing of additional reserve to cover wind turbine risk is likely to put upward pressure on the market price. The analysis used an average price approach that produces a more conservative estimate of benefits.

Net present value

- 29 The Authority's assessment of net present value for the three scenarios fell into the ranges shown in the graph below:

Figure 4: Net Present Value Range



- 30 The assessment indicated that the proposed fault ride through standards would have positive net benefits if the ultimate level of wind development were to the levels forecast in scenarios A or C. Scenario B represents the threshold of wind development where benefits marginally exceed costs.
- 31 The Authority considers the probability of wind development exceeding the threshold represented by scenario B in the next 10 years to be reasonably high. Scenario B levels of wind development would be exceeded if only a third of the 1672 MW of farm projects currently consented were completed within the next 10 years.

The amendment is consistent with regulatory requirements

- 32 The Code amendment is consistent with the Authority's statutory objective and with the requirements of section 32(1) of the Electricity Industry Act 2010.
- 33 The amendment is also consistent with the Authority's Code amendment principles; it is lawful and it will improve the reliability and efficiency of the electricity industry for the long-term benefit of consumers. The Authority has used a scenario based quantitative cost-benefit analysis to assess that the benefits exceed the costs.

Issues raised by submitters

- 34 The Authority has considered the issues raised by submitters, which fell into five categories:
- (a) whether the fault ride through standards should also apply to existing generating assets
 - (b) whether the transient over voltage standard should be based on the grid owner's transient over voltage standard at Haywards and Benmore or on international standards
 - (c) whether the transient over voltages that arise at Haywards and Benmore could be mitigated by use of other solutions that reduce the compliance requirements for generating assets
 - (d) the accuracy of the cost benefit analysis

(e) whether transitional provisions should apply when the standards are first introduced.

35 Each of these issues is discussed below.

Application to existing generating assets

What the Authority proposed

36 Existing generating stations that don't meet the proposed fault ride through standards and are unable to ride through transmission faults currently impose costs on others by:

- (a) not paying a share of the instantaneous reserve costs
- (b) increasing the quantity of instantaneous reserve required when the HVDC extended contingent event risk is binding.

37 The Authority proposed to apply the fault ride through standards to existing generating stations (as well as new generating assets) so that all generators imposing costs on others are allocated the costs they cause.

Submitters' views

38 Contact, Nova and Trustpower did not support the Authority's proposal to apply the fault ride through standards to existing generating assets. They were concerned that:

- (a) existing generating assets designed prior to the introduction of fault ride through standards may not be able to provide the required fault ride through capability
- (b) the cost of upgrading existing generating assets, where possible, to provide the required fault ride through capability, may be excessive
- (c) there may be a need for existing synchronous generators that meet the fault ride through standards to periodically demonstrate compliance through analysis and modelling work.

The Authority's decision

39 The Authority's role, among other things, is to promote the overall efficiency of the electricity industry for the long-term benefit of consumers. In this context, the Authority's proposal is an exacerbators pay approach - the parties whose actions or inactions cause costs should be responsible for mitigating those costs. Allocating costs to all generation asset owners whose assets increase system costs ensures that those parties have incentives to make efficient decisions for the long-term benefit of consumers.

40 If the Authority did not apply the fault ride through standards to existing generating stations, this would incentivise generation asset owners to find loopholes to avoid compliance. It would also create an inefficient barrier to new generating stations by enabling existing generation to impose costs on others and would create a 'non-level playing field' between existing and new generation.

41 The Authority recognises that owners of existing generating stations must carry out transitional work to assess the capability of their plant. The Code amendment now includes a transitional period for this work to be undertaken (refer to paragraphs 64 to 70 below on transitional provisions).

42 Generation owners who cannot or choose not to fully comply with the fault ride through standards (and more generally the asset owner performance obligations in part 8 of the Code) have the option to apply to the system operator for dispensations from full compliance.

43 Dispensations are conditional on asset owners paying any identifiable costs incurred by the system operator as a result of their non-compliance. In this respect, dispensations allow generation asset

owners to avoid excessive or uneconomic upgrade costs, but require owners to pay for any additional costs their non-compliance imposes on others. The dispensation process ensures that exacerbators pay for the costs they impose on others by ensuring that they internalise those costs. Allocating costs in this way promotes productive efficiency and efficient levels of reliable supply of electricity.

- 44 The Code includes obligations for asset owners to test their assets on an ongoing basis. The objective of the testing is to ensure that asset owners maintain their plant in compliance with the asset owner performance obligations and the performance information supplied to the system operator. Following a period of operational experience, the system operator may identify the need for some additional testing to verify ongoing fault ride through performance. This is part of the asset owner performance obligation framework.
- 45 The Authority has decided that the long-term interests of consumers are best served by applying the fault ride through standards equally to both new and existing generating stations. This will ensure that all exacerbators who increase system costs pay for those costs.

Grid owner's transient over voltage standard vs other standards

What the Authority proposed

- 46 The transient over voltage standards would be applied nationally and made up of the following two separate components:
- (a) A minimum absolute voltage standard consisting of 1.2 per unit⁵ (p.u.) for 2 seconds, 1.15 p.u. for the following 4 seconds, and thereafter the steady state limit of 1.1 p.u. (already set in the Code), plus
 - (b) A ratio-based transient over voltage standard to account for high transient over voltages that occur at Haywards and Benmore as a result of an HVDC bi-pole trip. These over voltages decrease with distance from Haywards and Benmore, and the ratio-based standard takes this effect into account.

Submitters' views

- 47 Meridian considered the over voltage aspects of the fault ride through standards to be more onerous than would reasonably be required to maintain system stability. In Meridian's view, the standards should not be based on a "worst-case" scenario, ie a 1200 MW trip of the HVDC bipole under a high starting voltage.

The Authority's decision

- 48 While the system operator studied a 1200 MW trip of the HVDC bipole, it did not recommend an over voltage standard based only on this scenario. The system operator recommended a standard aligned with the grid owner's HVDC transient over voltage criteria for Haywards and Benmore. While these criteria are a little conservative for a bipole loss of 1200 MW, they allow for the link's ultimate rating of 1400 MW.
- 49 Aligning the over voltage standard with the grid owner's HVDC transient over voltage criteria provides the grid owner with full operational flexibility under different service conditions.

⁵ Refers to the per unit system, used in power system analysis to express system quantities as fractions of a defined base unit quality. In the context of this paper, "per unit" refers to the ratio of grid line to line voltage to its base quantity of 220 kV or 110 kV, as applicable.

- 50 The Authority maintains that the over voltage aspects of the fault ride through standards are appropriate as they:
- (a) maintain system stability
 - (b) allow the grid owner the maximum operational flexibility to use the full transient over voltage criteria of the HVDC.
- 51 On this basis, the Authority has decided that the over voltage aspects of the fault ride through standards provide an appropriate level of reliability for the long-term benefit of consumers.

Other solutions that reduce compliance requirements

What the Authority proposed

- 52 Under the proposal, fault ride through standards would be added to the Code. These standards would require generation asset owners to ensure their assets remain stable and connected to the grid during transient system disturbances that are caused by major transmission system faults.

Submitters' views

- 53 Meridian, Mighty River Power and Trustpower questioned whether the over voltage ride through component of the fault ride through standards could be mitigated by other possible solutions such as:
- (a) the grid owner installing additional reactive plant at Haywards and Benmore
 - (b) setting lower fault ride through standards and covering residual generator risk through alternative means such as extended reserve.

The Authority's decision

- 54 Any grid investment solution involving the addition of dynamic reactive support plant would require Transpower to make high capital investments at Haywards and Benmore. The level of wind generation to plan for would be uncertain and the net benefits would be lower than the fault ride through standards.
- 55 Setting lower fault ride through standards and covering residual generator trip risks with extended reserve would increase the requirement for extended reserve and the costs incurred by reserve providers (network owners and grid connected loads). These additional costs would therefore not be paid by the generators who cause the costs. The incentives on generators to make efficient decisions would be weakened with an increased risk of higher costs being passed on to consumers.
- 56 The Authority has decided that the other possible solutions suggested above by submitters are not options that would achieve the objectives of the fault ride through standards.

Accuracy of the cost benefit analysis

The Authority's analysis

- 57 The Authority assessed the fault ride through standards as having net benefits in the range of \$0 to \$23 million, taking into account three different wind generation development scenarios, and discount rates in the range of 4 to 8 percent.

Submitters' views

- 58 A number of submitters commented that the cost benefit analysis could be improved by taking into account:

- (a) reserve sharing across the HVDC link
- (b) the cost of generators carrying out initial compliance assessments for existing generating assets and any ongoing monitoring and testing requirements.

The Authority's decision

- 59 Reserve sharing across the HVDC link and the proposed national market for instantaneous reserve were taken into account in the cost benefit analysis (refer to the section above on cost benefit analysis input assumptions).
- 60 Generators are already obligated under the Code to preserve power system stability and to support the system operator in meeting its principal performance obligations. The requirements that generators need to meet to remain stable during transmission faults are now clearer, as a result of the studies performed to develop the fault ride through standards. Given the development work that has now been carried out, it is possible that generators already have an obligation under the Code to check the performance of their plant against this new information.
- 61 The Authority considers that, even if the costs of assessing existing assets can be assumed to be an economic cost associated with the fault ride through standards, these costs are likely to be less than \$500,000 in total. Net benefits would still be positive for wind scenario A (moderate, concentrated in the North Island) and scenario C (high, diversified across New Zealand), and marginally negative for Wind scenario B. However, the Authority considers scenario B to be the least probable wind penetration scenario of the three considered.
- 62 The Authority recognises that the cost benefit analysis is sensitive to the selection of wind generation development scenarios. The Authority has compared its analysis with net benefits calculated using an independent set of electricity generation and demand scenarios – those produced by the Ministry of Business Innovation and Employment. The results of this analysis are attached as Appendix A, indicate net benefits greater than those assessed by the Authority in its consultation paper.
- 63 After reviewing submitter's comments, the Authority has decided that the assumptions underlying the analysis are sound, and that within the accuracy of a scenario-based assessment, the fault ride through standards have a positive net benefit.

Transitional provisions

What the Authority proposed

- 64 The Authority's proposal did not provide any specific transitional period of time for generation asset owners to assess the compliance of and upgrade options for their existing plant with the fault ride through standards.

Submitters' views

- 65 Mighty River Power commented that as the fault ride through standards are to apply to both existing and new generating assets, owners would need to undertake certain work to assess their portfolio of existing generating plant by:
 - (a) verifying manufacturers' specifications
 - (b) carrying out testing where performance records and specifications are unclear
 - (c) reviewing whether any plant upgrades are economic
 - (d) preparing dispensation applications, if required.

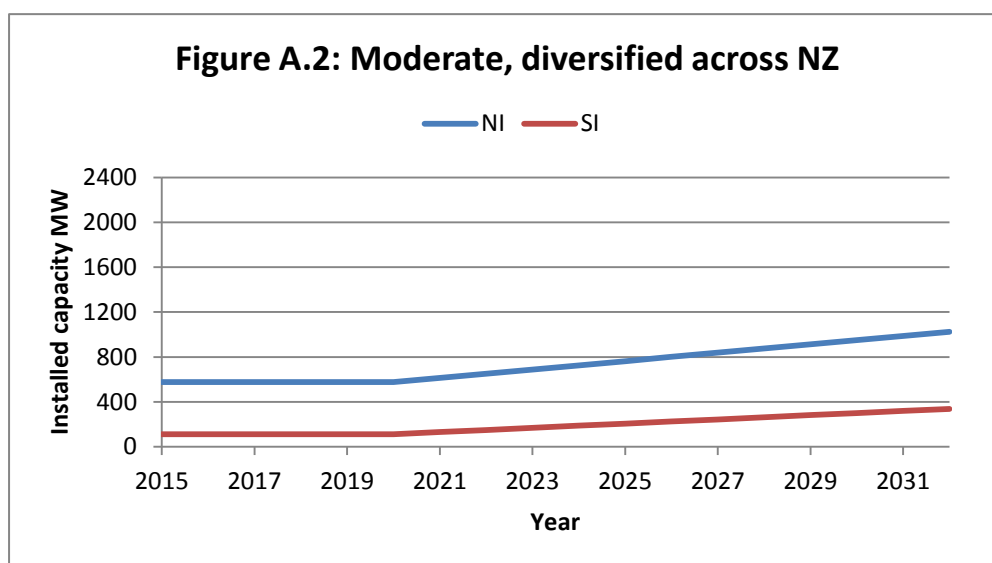
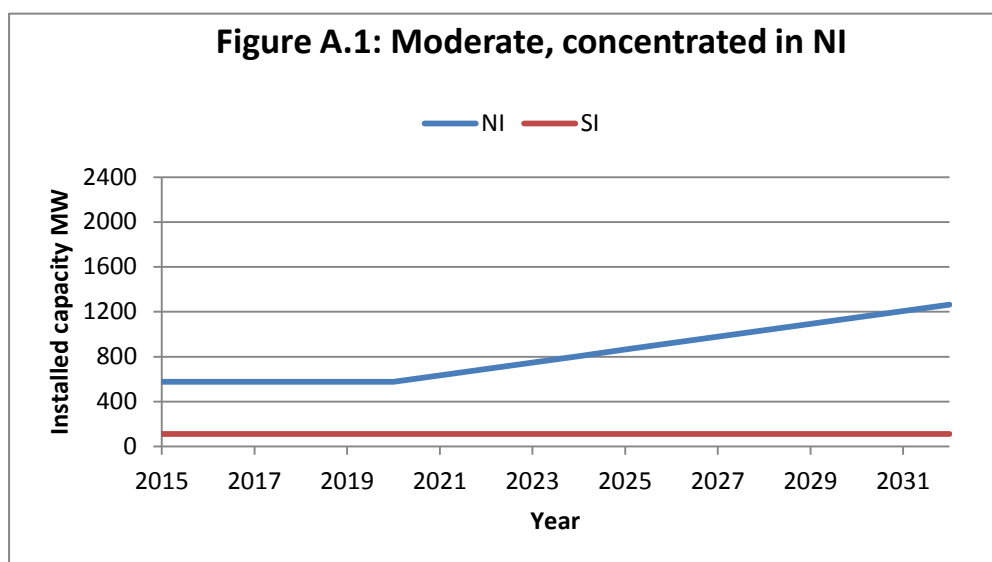
The Authority's decision

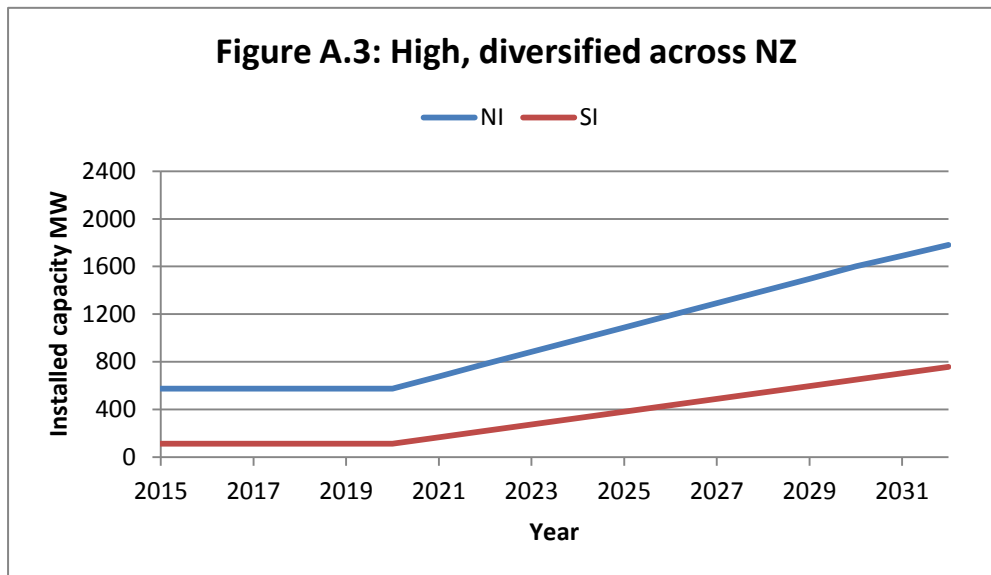
- 66 A transitional period would allow generation asset owners time to:
- (a) integrate their assessment work into existing work programmes
 - (b) make considered decisions about whether to make upgrades to plant.
- 67 A similar transitional issue existed when the asset owner performance obligations first came into effect under the then Electricity Governance Rules 2003 (now replaced by the Code). Dispensations were first introduced at that time and the rules allowed for a two-year interim dispensation period. During that interim period, any quantifiable costs arising from dispensations were not allocated to dispensation holders. This approach allowed asset owners a period of time to assess their options before costs were applied, without creating unwanted incentives for asset owners to delay their dispensations applications.
- 68 The Authority has decided to apply a similar transitional arrangement to the fault ride through standards. A two-year interim period will apply during which any quantifiable costs arising from dispensations will not be allocated to dispensation holders. This period aligns with the timeframe for the Authority's related project to review the allocation of instantaneous reserve costs. Until this project is completed, the system operator does not have automated systems in place to allocate any costs associated with fault ride through dispensations.
- 69 A two-year interim period also allows reasonable time for generation asset owners to assess their plant, seeking dispensations or alternatively making upgrade decisions, before any dispensation costs apply.
- 70 The transition period has minimal impact on the net benefits of the fault ride through standards as the benefits are largely derived from savings in reserve costs associated with new generating assets.

Appendix A: Wind generation Scenarios

Scenarios should reflect variability

- A.1 The Authority's assessment of the net benefits used three wind generation scenarios developed from the scenarios originally used by the wind generation investigation project. The project used simple wind generation scenarios developed by varying the historical rates of wind development to produce different growth rates. The Authority adjusted the original wind generation scenarios to allow for the flattening of electricity demand growth that has occurred since the global financial crisis.
- A.2 The three wind generation scenarios chosen to assess the calculated net benefits for the proposed Code amendment were:
- (a) moderate, concentrated in the North Island (the base case), shown in Figure 1
 - (b) moderate, diversified across New Zealand, shown in Figure 2
 - (c) high, diversified across New Zealand, shown in Figure 3.





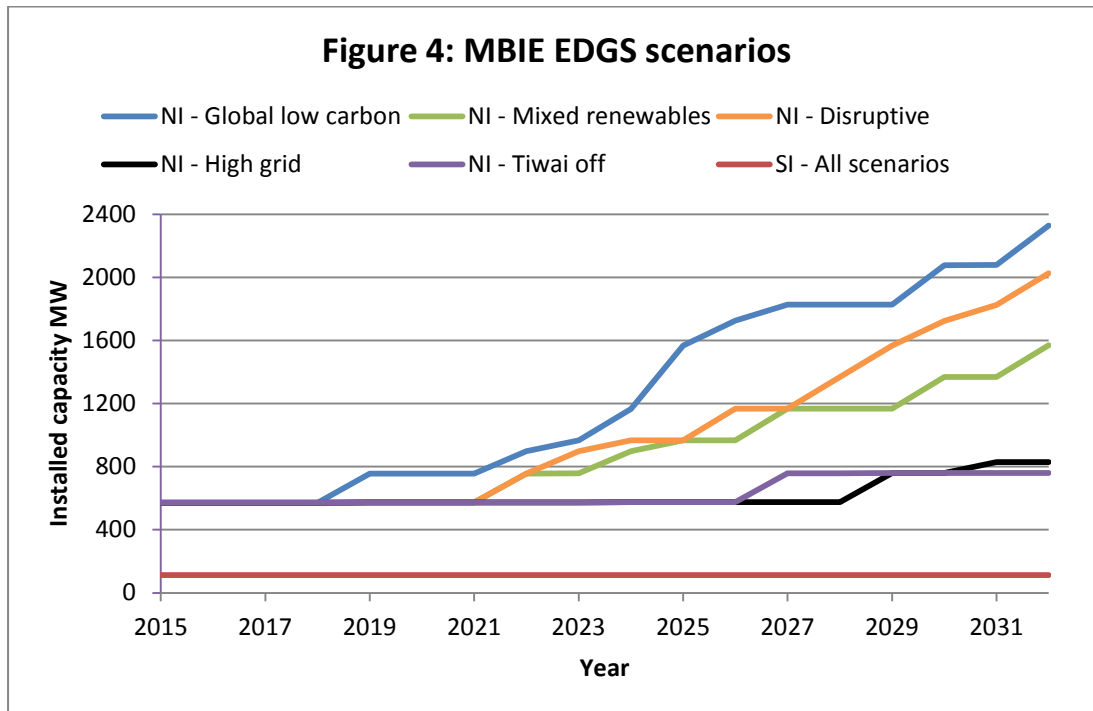
Comparison with independent wind development scenarios - EDGS

- A.3 The Ministry of Business, Innovation and Employment (MBIE) produces detailed electricity demand and generation scenarios (EDGS) that the Authority's scenarios can be tested against. MBIE used econometric models and projections for a number of modelling variables to develop the EDGS. The scenarios were developed using:
- (a) results from:
 - (i) MBIE's supply and demand energy model
 - (ii) the grid expansion model (originally developed by the former Electricity Commission for its *Statement of Opportunities* planning document)
 - (b) projections for:
 - (i) population
 - (ii) gross domestic product
 - (iii) exchange rates
 - (iv) oil price
 - (v) carbon emissions price
 - (vi) coal price
 - (vii) gas supply profiles
 - (viii) demand for aluminium and steel
 - (ix) electric vehicle uptake
 - (x) solar uptake.
- A.4 The scenarios replace those previously prepared by the Electricity Commission for the *Statement of Opportunities*. The regulatory role for the EDGS is set out in the Commerce Commission's Transpower Capital Expenditure Input Methodology Determination, 2012. Under the 2012

determination, Transpower must use the scenarios in the 'investment test' to determine the weighted average net benefits of proposals for major capital expenditure.

- A.5 MBIE consulted on a draft set of EDGS in 2015 and published the final set in August 2016, taking into account submitter's comments. The comparison cost benefit analysis below is based on the final August 2016 EDGS.
- A.6 Probability weightings are assigned to each scenario to reflect the uncertainties in underlying assumptions and calculated approaches. Both the EDGS and the earlier *Statement of Opportunities* apply an equal probability weighting to all five scenarios.
- A.7 The EDGS consist of five scenarios described as follows:
- (a) global low carbon
 - (b) disruptive
 - (c) mixed renewables
 - (d) high grid (high gas availability)
 - (e) Tiwai off.
- A.8 The scenarios use the wind farm build schedule shown in Table 1 below. The order and timing of wind farm commissioning is adjusted in accordance with input projections for each scenario. The build schedule is shown graphically in Figure 4 below.

Table 1			
Plant Name	GXP code	Island	Installed Capacity (MW)
Mill Creek	WIL	North Island	60
Turitea	LTN	North Island	183
Hawkes Bay windfarm Maungaharuru	RDF	North Island	225
CastleHill stage1	GYT	North Island	200
CastleHill stage2	GYT	North Island	200
CastleHill stage3	GYT	North Island	200
Project CentralWind	MAT	North Island	120
Waitahora	WDV	North Island	156
GenericMediumWind3 WanganuiTaupo	BPE	North Island	200
Taharoa	HTI	North Island	54
GenericMediumWind4 HawkesBay	RDF	North Island	200
Puketoi	BPE	North Island	159
GenericMediumWind2 Waikato	HLY	North Island	200
GenericLargeWind1 Manawatu stage1	WDV	North Island	250
GenericLargeWind1 Manawatu stage2	WDV	North Island	250

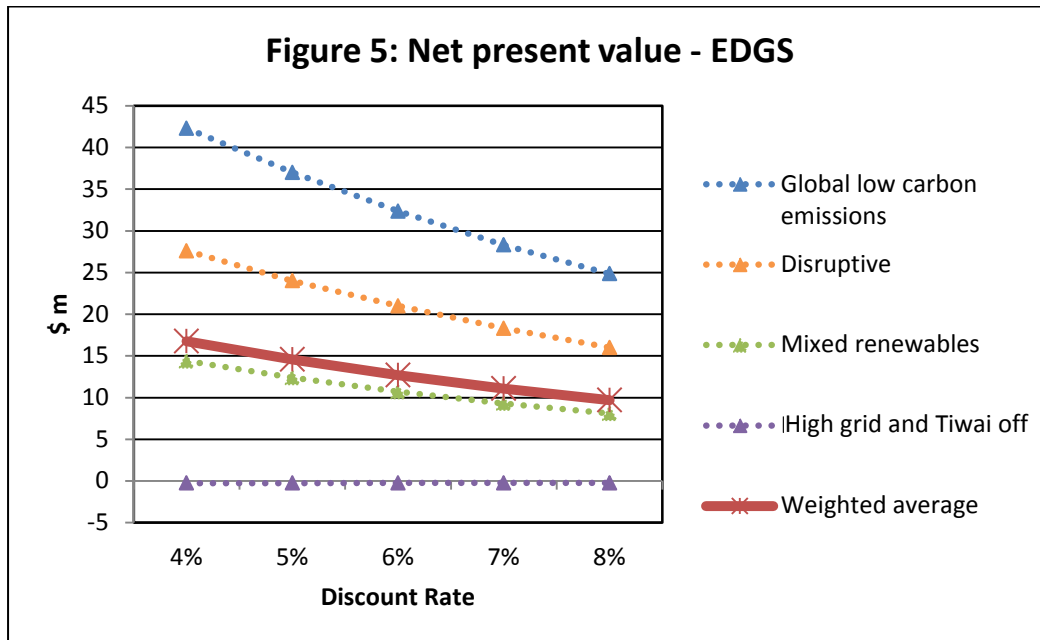


- A.9 The main difference between the EDGS and the Authority's scenarios is that the EDGS include no new wind generation build in the South Island during the period of interest. The Authority included a limited quantity of new generation in the South Island in two of the three scenarios. The EDGS assume the current transmission pricing methodology will continue to apply over the duration of the scenarios. This accounts for all new build wind farms being scheduled the North Island for the duration of the scenarios.

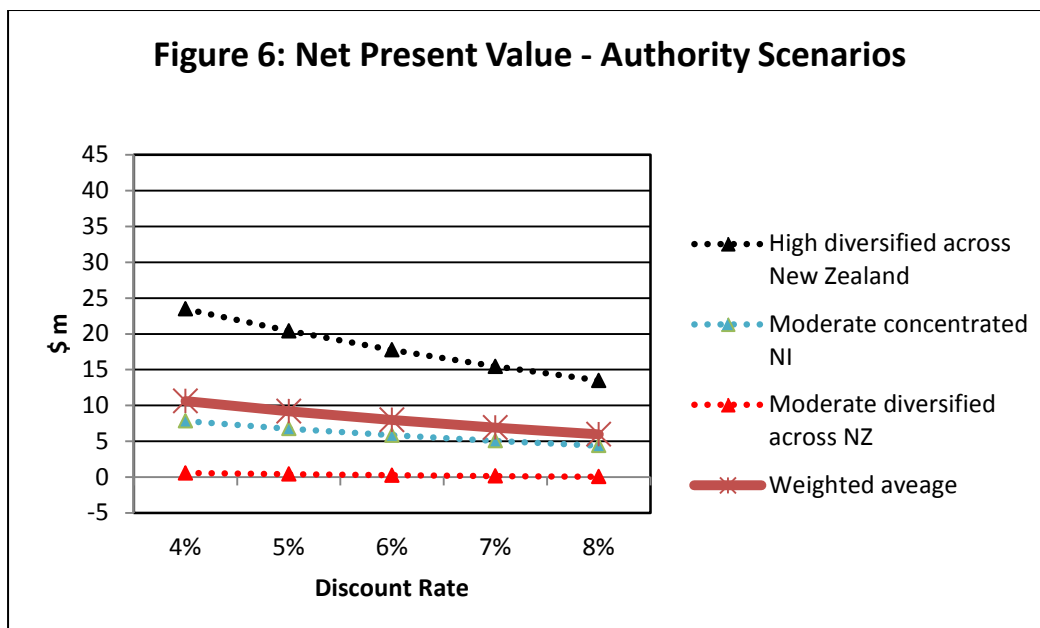
Cost benefit analysis

- A.10 The EDGS are intended to be used to calculate the 'weighted average net benefits' of an investment. Transpower must apply the EDGS using an equal weighting for each scenario when applying the grid investment test to major capital expenditure⁶.
- A.11 Applying the EDGS in accordance with the grid investment test to the Authority's cost benefit analysis model for the proposed fault ride through amendment produces the net present values shown in Figure 5 below. Note that the 'net present value' line in the graph is the same for two of the scenarios (Tiwai off and high grid).

⁶ Under the Commerce Commission's Transpower Capital Expenditure Input Methodology Determination, 2012.



- A.12 The weighted average net present value of the five scenarios is in the range of \$10 – 17 million, over discount rates of 4 – 8%. By comparison, the scenarios the Authority consulted on produce a more conservative weighted average net present value in the range of \$6 – 11 million, as shown in Figure 6 below.



- A.13 If no wind generation was built in the next 15 years, the net present value would be close to zero, as shown in the MBIE “high grid” and “Tiwai off” scenarios, and the Authority’s “moderate diversified across NZ” scenario. This is because there would be no change in the quantity of reserve required to maintain a secure power system.

Conclusions

- A.14 The scenarios the Authority consulted on produce a more conservative estimate of net benefits than estimates based on EDGS as applied to the grid investment test.

- A.15 There are no scenarios than could result in a lower net present value than the High grid and Tiwai exit EDGS scenarios. Net benefits assessed using MBIE's EGDS are in the range of \$10 – 17 million. This compares with the assessed range of \$6 – 11 million using the Authority's scenarios.