Wind Offer Arrangements

Decision Paper

24 April 2018

Contents

1 Decision

1.1 The Electricity Authority (Authority) has decided to amend Parts 1 and 13 of the Electricity Industry Participation Code 2010 (Code). The amendment will:

(a) require wind farm owners ("intermittent generators" in the Code) to submit offers in a new form with five offer bands rather than one. The form will also have a new field for a "forecast of generation potential" (in MW)

(b) change provisions relating to wind farm owner's "persistence offers" to ensure they reflect a forecast of generation potential rather than merely what the wind farm is currently generating

(c) provide for schedules, including real time dispatch schedules, to use the new offer information as an input

(d) require wind farm owners to comply with any dispatch instruction to generate below their forecast of generation potential level. If the dispatch instruction is to generate at their potential level, there is no dispatch compliance obligation

(e) require wind farm owners to generate at least its final forecast of generation potential less 30 MW, unless they have an allowable reason. Allowable reasons include that the generator is following a dispatch instruction, that the wind resource prevents higher generation, or that automated asset protection systems have operated (eg, wind over-speed protection systems)

(f) allow constrained on payments to be paid to wind farm owners, consistent with payments that are currently made to other types of generation.

1.2 These changes will together promote the efficiency and reliability limbs of the Authority's statutory objective by:

(a) enabling the lowest-cost generators to be scheduled and dispatched

(b) reducing the risk of under-frequency events which can lead to widespread loss of supply.

2 Background

2.1 The Authority's statutory objective is to promote competition in, reliable supply by, and the efficient operation of the electricity industry for the long-term benefit of consumers.

2.2 In September 2017, the Authority consulted on a proposal to improve wind offer arrangements in the Code.[1]

2.3 The issues identified with the current arrangements that require wind farm owners to offer their generation at $0.01/MWh or $0.00/MWh were:

(a) there was no clear mechanism for wind farm owners to economically withdraw their generation when spot market prices were below their short-run marginal cost (SRMC)

[1] https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/wind-generation-offers/consultations/#c16714

(b) there was no clear prohibition in the Code against a wind farm owner to physically withdraw generation from the spot market in real-time without providing adequate notice to the system operator.

2.4 The objective of the proposal was:

(a) to enable wind farm owners to withdraw their generation in an efficient, centrally coordinated way when the spot market price is below their SRMC

(b) to prevent wind farm owners withdrawing large amounts of generation in ways that are not well co-ordinated.

2.5 This paper sets out the Authority's decision to amend Parts 1 and 13 of the Code and gives reasons for the decision.

2.6 The Code defines grid scale intermittent generation to be wind generation only. The Authority recognises that other new forms of grid scale intermittent generation are possible, eg solar, battery energy storage systems etc. The Authority will consider adding a new project to its 2018/19 work programme to look at the broader issue of removing barriers and providing flexibility where appropriate to allow these new technologies to enter the market.

2.7 More information about the Wind Offer Arrangements project is available from the Authority's website at: https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/wind-generation-offers/.

3 Why the Authority made this decision

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

3.1 After considering all submissions on the Code amendment proposal, the Authority believes the final version of the amendment will deliver long-term benefits to consumers by:

(a) enabling the lowest-cost generators to be scheduled and dispatched to meet demand. In the short-term this leads to a productive efficiency gain and, in the longer term, promotes investment in more efficient generating plant. At present, wind generation is scheduled and dispatched to meet demand even if it has a higher SRMC than other generation plant that is not scheduled or dispatched.

(b) reducing the risk of under-frequency events (which can lead to widespread loss of supply) by preventing wind farm owners from rapidly withdrawing their generation without providing any notice to the system operator.

3.2 The Authority does not expect the amendment to have a material effect on competition in the industry.

The benefits of the amendment are greater than the costs

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

3.4 Benefits of $5.6 million arise because lower cost generation will be used to meet demand. This recognises that wind farm owners have a SRMC of generation which arises from wear and tear on generation assets. The amendment will allow wind farm

owners to withdraw their generation when market prices are below that SRMC, reducing the aggregate cost of meeting demand.

3.5 Costs of $2.9 million arise mainly from the costs to:

(a) wind farm owners of revising their offer systems to comply with the new arrangements

(b) the system operator of changing its systems.

3.6 These costs are slightly higher than the costs of $2.7 million published in the consultation paper. The small increase in expected costs arises because the Authority has recently obtained high level cost estimates from NZX Limited for implementing the amendment. These costs relate to the WITS manager and the clearing manager roles.

3.7 Appendix A sets out an updated cost-benefit analysis (CBA) incorporating the small increase in expected costs.

The amendment is consistent with regulatory requirements

3.8 The amendment is consistent with the Authority's statutory objective and with the requirements of section 32(1) of the Electricity Industry Act 2010.

3.9 The amendment is also consistent with the Authority's Code amendment principles. It is lawful and will improve the reliability and efficiency of the electricity industry for the long-term benefit of consumers. The Authority has clearly identified an efficiency gain and has used a quantitative CBA to assess long-term net benefits for consumers.

4 The Authority considered issues raised in submissions

4.1 Parties that made submissions are listed in Table 1.

4.2 You can find all submissions and a summary of submissions on the Authority's website at:

https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/wind-generation-offers/consultations/

Table 1 List of submitters

Generator	Generator-retailer	Other
NZ Windfarms Limited[2] (NZ Windfarms) Tararua Wind Power Limited (Tararua)	Contact Energy Limited (Contact) Genesis Energy Limited (Genesis) Mercury Energy Limited (Mercury) Meridian Energy Limited (Meridian) Trustpower Limited (Trustpower)	NZ Wind Energy Association Transpower New Zealand Limited (Transpower)

4.3 Issues raised by submitters fell into five categories:

(a) the meaning of persistence model

(b) the 30 MW limit in proposed clause 13.87A and the related reporting regime

(c) the effect of clause 13.87B

(d) definition of bona fide physical reason

(e) how the CBA relates to the earlier analysis published by the former Wholesale Advisory Group (WAG).

4.4 Each of these issues is discussed below.

The meaning of "persistence model"

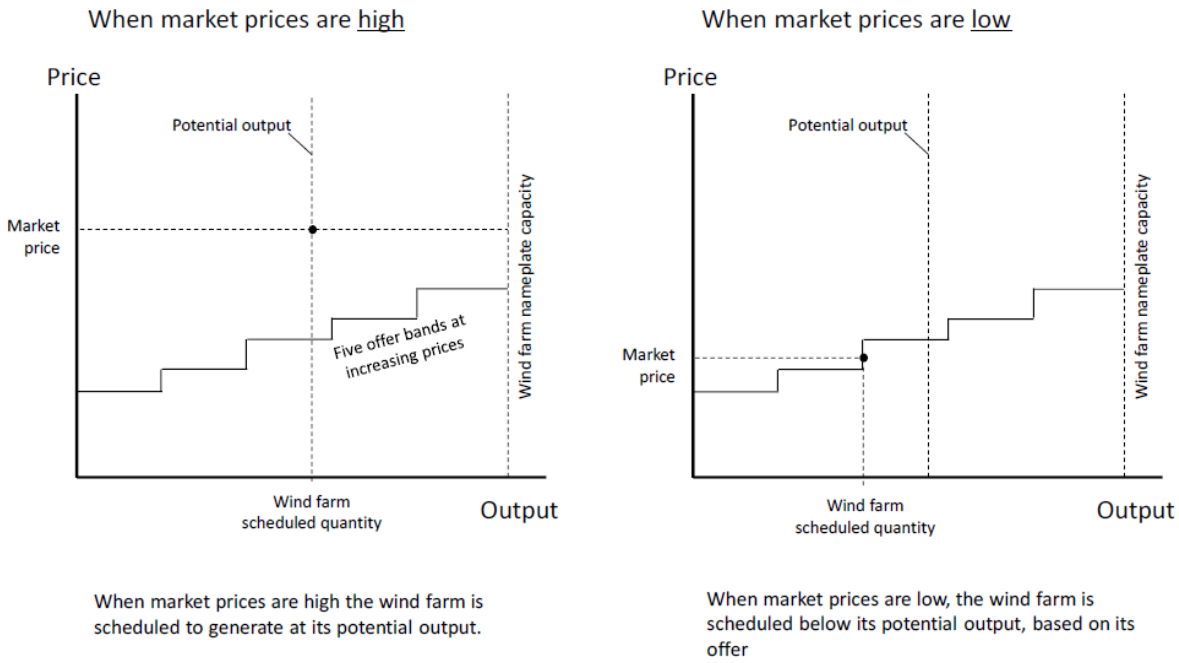
What the Authority proposed

4.5 At present, wind farm owners offer their generation in a single band with a price of $0.00 or $0.01/MWh. The wind farm owner's forecast of its output is submitted as the offer quantity. Within the final two hours before the beginning of the trading period, a wind farm owner must submit a forecast for the trading period at least once every half hour using a "persistence model". A persistence model is one that takes into account only actual output (if the wind farm is generating) and any expected changes in the wind farm's availability/capability.

4.6 The proposal would change the structure of wind farm owners' offers. Offers would be submitted in up to five price-quantity bands. This is illustrated in Figure 1 below. Since wind generation is dispatched based on price, the forecast must be a forecast of *generation potential* (ie, what the wind farm is expected to produce based on the wind resource, plant capability, and plant availability, not a forecast of what is expected to be dispatched). The forecast of generation potential is a separate field in the offer (it is not the sum of the offered quantities).

[2] NZ Windfarms provided a public submission and also provided further commercially confidential information to the Authority which has not been published.

Figure 1: Wind farm offers in five bands



The proposed change in the structure of wind offers makes it more important to consider how a persistence-based forecast should be prepared when a wind farm owner is dispatched down (wholly or partially) based on price.

The proposed change to the meaning of "persistence model" in clause 13.18A(3) was as follows:

13.18A Intermittent generators to submit revised ~~offers~~ forecast of generation potential

(3) For the purposes of this clause, a persistence model means a method for producing a forecast of the **intermittent generator's** generation, in **MW**, that takes into account only the following factors:

(a) if the relevant **intermittent generating station** is generating at the time the revised **offer** is submitted, the actual output from the **intermittent generating station** at that time~~; and~~;

(aa) an assumption that the wind conditions at the time at which the revised **forecast of generation potential** is prepared will persist until the end of the **trading period** to which the revised forecast relates;

(b) any expected changes in availability and capability of **generating plant** forming all or part of the relevant **intermittent generating station**.

4.7 The intention of this proposed change was to provide for a wind farm owner to prepare a forecast based on persistence of the *wind conditions* (in comparison to the persistence of current wind farm output). This is particularly relevant if the wind farm owner is currently dispatched to 0 MW. In that case, a forecast based on persistence of output

would be 0 MW, while a forecast based on persistence of the wind conditions will recognise the potential to generate some positive quantity.

Submitters' views

4.8 Tararua submitted that the drafting of clause 13.18A(3) was confusing. The clause did not specify whether the forecast *must be* based on wind persistence when a wind farm is currently dispatched below its forecast of generation potential (curtailed). Paragraph 4.2(b) of the consultation paper suggested this approach was obligatory.

4.9 Tararua proposed:

(a) using the term "wind persistence" in clause 13.18A(3) to indicate that wind conditions are considered to persist, not necessarily the output

(b) changing clause 13.18A(3)(a) to read, "if the [wind] farm is not curtailed, the actual output from the intermittent generating station at the time…"

(c) removing the word "only" in the header clause of 13.18A(3) to allow wind farm owners to use the best information they have available to prepare this forecast.

Subsequent Authority discussions with wind farm owners

4.10 As part of considering Tararua's submission, the Authority discussed the drafting of clause 13.18A(3) with wind farm owners that would be obliged to comply with that clause.

4.11 Meridian raised a concern relating to the phrase "any expected changes in availability and capability". Meridian was concerned the phrase was ambiguous because it leaves some discretion to wind farm owners about what they signal to the market in forecasts. In particular, it could be read to suggest that any change must be included in forecasts, no matter how minor. Meridian suggested the Authority clarify that changes to availability below a certain MW value would not have to be signalled in the forecast.

The Authority's decision

4.12 The Authority has decided to change the proposed drafting of clause 13.18A(3) to address the concern raised by Tararua. The new drafting clarifies that a forecast of generation potential under clause 13.18A should be consistent with the assumption that wind conditions will persist into the relevant trading period. This may be different from an assumption that the current level of *output* will persist, especially where the wind farm owner's plant is currently dispatched below its forecast of generation potential.

4.13 The Authority has simplified the new drafting of clause 13.18A(3) so that it does not specify the categories of inputs that may or may not be used to produce the forecast of generation potential.

4.14 The new drafting of clause 13.18A(3) is:

> **13.18A Intermittent generators to submit revised forecast of generation potential**
>
> **…**
>
> (3) For the purposes of this clause, a resource persistence model means a method for producing a forecast of the **intermittent generator's** generation for a **trading period**, in **MW**, that is derived from the expected availability and capability of **generating plant** forming all or part of the relevant **intermittent generating station**, on the assumption that the wind (or other resource) conditions at the

time at which the forecast is prepared will persist throughout the **trading period** to which the forecast relates.

4.15 The following strikethrough drafting shows the changes that the proposal would make to the drafting that is presently in force.

> **13.18A Intermittent generators to submit revised ~~offers~~ forecast of generation potential**
>
> **…**
>
> (3) For the purposes of this clause, a resource persistence model means a method for producing a forecast of the **intermittent generator's** generation for a **trading period**, in **MW**, that is derived from the expected availability and capability of **generating plant** forming all or part of the relevant **intermittent generating station**, on the assumption that the wind (or other resource) conditions at the time at which the forecast is prepared will persist throughout the **trading period** to which the forecast relates. ~~takes into account only the following factors~~:
>
> ~~(a) if the relevant **intermittent generating station** is generating at the time the revised **offer** is submitted, the actual output from the **intermittent generating station** at that time; and~~
>
> ~~(b) any expected changes in availability and capability of **generating plant** forming all or part of the relevant **intermittent generating station**.~~

4.16 The phrase “expected availability and capability” is used in clause 13.18A(3). The Authority considers this wording would not require a wind farm owner, in forming an expectation of turbine availability, to make efforts and undertake enquiries beyond those that are reasonable.

4.17 The Authority notes that the 30 MW rule in clause 13.87A (discussed below) will place some pressure on wind farm owners to make efforts and undertake enquiries to determine when substantial turbine outages are planned.

4.18 If a wind farm owner does not incorporate substantial turbine outages in its forecast of generation potential in clause 13.18A, the wind farm:

(a) is more likely to exceed the 30 MW limit in clause 13.87A

(b) will be obliged to provide a reason.

4.19 The Authority considers small turbine outages are less likely to have this effect.

The 30 MW limit in proposed clause 13.87A and the related reporting regime

What the Authority proposed

4.20 The Authority proposed that wind farm owners would be obliged to comply with a flagged dispatch instruction. Dispatch instructions would be flagged for compliance if they were for an amount less that the wind farm’s potential output. In addition to dispatch obligations, a wind farm owner would be obliged to comply with a new clause 13.87A.

4.21 Under this clause, a wind farm owner must generate at least its final forecast of generation potential less 30 MW, unless it does so to comply with a dispatch instruction or has a bona fide physical reason (which is amended to include a lack of wind resource). It must report on any trading periods where this limit is exceeded. Reports are

to be prepared monthly and submitted within five business days after the end of the month.

Submitters' views

4.22 Contact suggested that the 30 MW limit specified in clause 13.87A should instead be a percentage of the wind farm's capacity. As an example, Contact suggested that a 45 MW wind farm should not be free to withdraw 66 % of its capacity without adequate explanation.

4.23 Mercury also noted that wind farms differ in size and suggested that a percentage measure would be more appropriate.

4.24 Tararua was concerned about the effect of this change for larger wind farms, such as the consented 200 MW Kaiwera Downs Wind Farm. In such farms, a drop of 30 MW over a half-hour due to changing wind conditions may be relatively common, creating an excessive compliance burden on the wind farm owner to analyse and report on each occurrence. Tararua suggested using the greater of 30 MW or a percentage of nameplate capacity, and/or the ability for the limit to be adjusted on a case-by-case basis by the System Operator given operational experience.

4.25 Tararua was concerned the proposal would introduce an unreasonable compliance burden on large wind farm owners to report primarily on routine meteorological events affecting generation. Tararua suggested a six-monthly cycle rather than a monthly cycle for reporting, and that reporting be only on specific events of interest. It also submitted that five business days for reporting is too short a time. Given that complex information may need to be analysed, Tararua suggested the end of the following calendar month as the reporting deadline.

The Authority's decision

4.26 **Small wind farms should have a lower limit than 30 MW:** The Authority considers that the arguments put forward by Contact and Mercury in favour of a smaller threshold for smaller wind farms are not clear. There would have to be a strong reason to allow the withdrawal of a 29 MW string of turbines by a large wind farm owner, while preventing a small wind farm owner from withdrawing an identical string of turbines. In addition, wind farms that are 10 MW or smaller are not required to submit offers. Owners of these wind farm owners don't receive dispatch instructions and can withdraw their generation at any time.

4.27 The obligation for a wind farm owner to generate at least its final forecast of generation potential, less 30 MW, is intended to prevent large uncoordinated withdrawals of wind generation that could impact on scheduling and security. The impact on scheduling and security will depend on the MW size of the withdrawal, not on its size as a percentage of capacity.

4.28 The Authority considers a lower limit for small wind farms would introduce an undue complication that is not necessary for scheduling and security purposes, and that the proposal should not be changed on this point.

4.29 **Large wind farms should not have a higher limit than 30 MW:** The largest wind farm currently operating in New Zealand and injecting at a single grid injection point is the Tararua Stage 3 wind farm (93 MW). Analysis of two years' historic data suggests we would expect an average of only two trading periods each month for that wind farm, where metered generation was more than 30 MW below the final forecast of generation

potential. (This does not count trading periods where the wind farm is dispatched below its potential based on price.)

4.30 The Authority expects forecasting will be improved as a result of this amendment and that the average number trading periods where the limit is exceeded will decrease.

4.31 Even for a hypothetical larger wind farm of 200 MW, our analysis suggests the number of trading periods requiring explanation would average around 14 to 20 per month, based on the current accuracy of forecasting. The analysis required to prepare such a report, and the compiling of the report, is not expected to be unduly onerous, even for a 200 MW wind farm injecting at a single grid injection point.

4.32 **Making reporting less onerous:** The Authority will make reporting less onerous by removing the requirement to report when metered generation is more than 30 MW below the final forecast of generation potential due to the wind farm owner complying with a dispatch instruction. The Authority will already have access to data on the final forecast of generation potential, metered generation, and dispatch instructions so there is little to be gained from requiring further reporting in such cases.

4.33 The Authority considers that monthly reports are appropriate. A six monthly reporting frequency would mean that, if the Authority has questions about the report for a particular trading period, plant operators would remember fewer details about the particular operating conditions.

4.34 However, the Authority agrees that a longer period should be provided for reporting. This will reduce the compliance burden while still assisting the Authority to monitor compliance with the provision. A timeframe of the end of the following calendar month seems a reasonable suggestion and the Authority's proposal will be amended accordingly.

The effect of clause 13.87B – Intermittent generating station groups

What the Authority proposed

4.35 To understand the effect of clause 13.87B (as it was proposed in the consultation paper), it is necessary to understand the role of clause 13.87A and its relationship with dispatch compliance. The 30 MW rule in clause 13.87A operates in parallel with the dispatch compliance obligations in clause 13.82. The 30 MW rule in clause 13.87A is subservient to dispatch compliance in the sense that the need to comply with dispatch provides an acceptable reason for generating more than 30 MW below the final forecast of generation potential. However, if a wind farm owner receives a dispatch instruction that is *not* flagged for compliance, then the 30 MW rule in clause 13.87A becomes the primary provision restricting the range of permissible levels of output.

4.36 Some wind farms in New Zealand have two nodal points of injection and are therefore treated as two separate wind farms, with separate offers and dispatch instructions at each node. The consultation paper did not propose to change that approach. Offers and dispatch instructions would have continued to relate to a single point of injection. In other words, a wind farm with two points of injection would provide two offers and would receive two dispatch instructions: one at each point of injection.

4.37 Clause 13.87B was intended to provide a mechanism to allow a wind farm with two points of injection to be treated as a single wind farm *but only for the limited purpose of complying with the 30 MW rule in clause 13.87A*. This means the wind farm with two points of injection that has dispatch instructions *not flagged for compliance* would have some leeway to transfer generation between points of injection. It would have a total of 30 MW of leeway overall (not twice that). The wind farm owner could apply to the Authority requesting its plant to be treated as a single wind farm for the purpose of clause 13.87A. The Authority would take account of the system operator's views in making the approval decision.

Submitters' views

4.38 Transpower was concerned that the provision would introduce block dispatch of wind and that this had not been properly considered by the system operator. Transpower considered it would be more appropriate for the system operator to have the approval role.

The Authority's decision

4.39 The proposal in the consultation paper did not intend to introduce block dispatch of wind. Offers and dispatch for wind would have continued to relate to each individual point of injection. Clause 13.87B would have provided for the grouping of individual wind farms, *but only for the purpose of compliance with clause 13.87A*. The Authority acknowledges it would have been useful to have made this point more clearly in the consultation paper.

4.40 The Authority has discussed clause 13.87B with stakeholders that may have benefited from its intended flexibility. The Authority has determined the clause would not be of substantial use to wind farms. Consequently, the Authority now proposes to remove clause 13.87B so that it is no longer part of the proposal.

Definition of bona fide physical reason

What the Authority proposed

4.41 At present the term “bona fide physical reason” (BFPR) is used in offer preparation provisions in Part 13 of the Code in the context of submitting revised bids and offers during the gate closure period. A generator has certain rights under a grid emergency to revise its offer during the gate closure period where the revision is necessary due to a BFPR. One component of the BFPR definition provides that a generator has a BFPR in a situation where personnel or plant safety is at risk.

4.42 Under the proposal the term BFPR would have a secondary role. Clause 13.87A prevents a wind farm owner from generating more than 30 MW below its final forecast of generation potential unless it has a good reason, which includes a BFPR.

4.43 The proposal would amend the definition of BFPR in Part 1 of the Code. The provision about personnel or plant safety would be retained. In addition, wind (intermittent) generators would have their own section within the definition of BFPR. Among other things, a BFPR would arise where the wind farm owner reduces generation “to prevent an un-modelled transmission asset from exceeding its ratings” (refer to paragraph (ba)(ii)(A) of the definition of BFPR in Part 1 of the Code).

Submitters’ views

4.44 Meridian suggested amending the definition of BFPR to remove any doubt that the phrase “plant safety is at risk” includes a situation where automated asset protection systems have actually operated, for example wind over-speed protection systems.

4.45 Transpower submitted that the definition of BFPR does not make clear how a generator is to know if transmission assets are "un-modelled".

The Authority’s decision

4.46 The Authority considers the phrase “plant safety is at risk” already clearly covers a situation where automated asset protection systems have operated. Consequently no change is required to address that issue.

4.47 The Authority added the following new definition for “un-modelled transmission asset” to Part 1 of the Code:

un-modelled transmission asset means a **transmission asset** for which the **system operator's dispatch** optimisation model does not include **asset** ratings as a **constraint**

4.48 A transmission asset is *modelled* within the system operator’s scheduling tool (SPD) if information about the rating of that asset is input into the model as a constraint. Flows scheduled by SPD over the asset will then not exceed its rating. A transmission asset is *un-modelled* if SPD does not have this constraint information. In this case it will be up to the asset owner to ensure the local generator manages its offers and its generation in such a way that the rating/capacity of the asset is not exceeded.

How the CBA relates to the earlier CBA published by the Wholesale Advisory Group

What the Authority proposed

4.49 In July 2016, the Wholesale Advisory Group (WAG) gave advice to the Authority on the wind offers project, which included a proposal for a "proportional solution". An alternative option labelled "a more sophisticated wind integration system" was also discussed. For convenience we label those options as "simple" and "sophisticated". The present value of the costs and benefits of those proposals over a discount period of 15 years was as follows:

Table 2: WAG's CBA in July 2016

Option	Benefit	Cost	Net Benefit
Simple (proposed by the WAG)	$3.6m	$0.5m	$3.1m
Sophisticated (treated by the WAG as an alternative approach)	$3.6m	$8.0m	-$4.4m

4.50 After further consideration of the WAG's simple and sophisticated options, the Authority found that the sophisticated option had the greater net benefits of the two options. There were some differences between the options considered by the WAG and the options considered by the Authority in the September 2017 consultation paper, but for the purposes of the CBA, the differences were not significant).

Table 3: Authority's CBA in September 2017

Option	Benefit	Cost	Net Benefit
Simple (treated by the Authority as an alternative approach)	$1.7m (30% of the benefits below)	$1.1m	$0.6m
Sophisticated (proposed by the Authority)	$5.6m	$2.7m	$2.9m

Submitters' views

4.51 Transpower noted that the consultation paper did not reconcile the Authority's CBA with the WAG's CBA. In particular, Transpower noted that the simple option had a net benefit of $3.1m in the WAG's July 2016 analysis, while the Authority proposed the sophisticated approach in September 2017 with a net benefit of only $2.9m. Transpower considered this needed to be explained.

A reconciliation of the July 2016 and September 2017 CBAs

4.52 We can compare the WAG and Authority's CBAs by comparing each of the four cells in the benefit/cost, simple/sophisticated matrix in Table 2 and Table 3 above.

(a) **Benefits of sophisticated approach:** These benefits increased from $3.6m in July 2016 to $5.6 m in the September 2017 CBA. This was due primarily to the use of a wider dataset in the September 2017 analysis to produce more reliable non-wind supply curve. The September 2017 CBA looked at three years of data (in step 6 of the published CBA) to determine the slope of the non-wind supply curve from which withdrawn wind would be replaced. The July 2016 analysis was based on data for an indicative single day. The non-wind supply curve was somewhat

flatter in the September 2017 analysis. This meant that withdrawn wind could be replaced relatively more cheaply, increasing the benefits of the sophisticated option.

(b) **Costs of sophisticated approach:** This is the most significant change between the two CBAs. The July 2016 estimate was $8.0 million but this was reduced to $2.7 million in the September 2017 CBA. In July 2016, the WAG had no detailed information from the system operator on which to estimate the system operator's implementation costs. In the absence of that information, a cost was estimated based on knowledge of estimated costs for other broadly similar projects. The cost was high because the WAG believed that complex changes would be required to dispatch systems and these are known to be costly. The September 2017 CBA used cost information provided by the system operator as the basis for the cost estimate. The system operator advice indicated there was sufficient flexibility within existing systems to avoid the costly system changes envisaged by the WAG when forming the cost estimate in their July 2016 CBA.

(c) **Benefits of the simple option:** In the July 2016 CBA, the simple option was expected to have the same benefits as the sophisticated option. The September 2017 analysis recognised that the simple approach would rely on the accuracy of forecast prices to make withdrawal decisions, and that the accuracy of forecast prices would present problems for wind farm owners making withdrawal decisions on that basis. After consideration of the accuracy of those forecast prices and the risks to wind farm owners of withdrawing (based on expectations of low prices) only to find that final prices were high, the Authority estimated that the benefits of the simple approach could be around 30 % of the benefits of the sophisticated approach.

(d) **Costs of the simple approach:** The costs of the simple approach were estimated at $0.5 million in the July 2016 analysis, but increased to $1.1 million in the September 2017 analysis. This is due to a higher estimate for the cost to wind farm owners of making the necessary changes to their systems.

4.53 These changes led to the sophisticated approach having a higher net benefit than the simpler approach. The September 2017 CBA shows a net benefit of $2.9 million from the sophisticated approach compared with a net benefit of $0.6 million from the simple approach. Consequently the sophisticated approach was preferred and proposed in the September 2017 consultation paper.

4.54 Note that, since the consultation paper was published in September 2017, the Authority has obtained high level cost estimates from NZX for implementing the proposal. These costs relate to the WITS manager and clearing manager roles. The costs are approximately $0.2 million higher than those incorporated in the September 2017 CBA. Despite these cost increases, the sophisticated approach still has a positive net benefit, which is higher than the simpler approach. An updated CBA incorporating these revised costs is set out in Appendix A.

Appendix A Updated cost-benefit analysis

Updated cost information

A.1 The Authority published a CBA in section 4 of the consultation paper released in September 2017. Since that date the Authority has obtained high level cost estimates from NZX for implementing the proposal. These costs relate to the WITS manager and clearing manager roles. The result is that expected project costs are approximately $0.2 million higher than detailed in the consultation paper. This change has a small impact on net benefits and on the sensitivity analysis.

A.2 This appendix provides an updated CBA incorporating the new information about costs.

Net benefits

A.3 The base case net benefits of the proposal are expected to be $2.7 million. This is based on expected benefits with a present value of $5.6 million over a 15 year discount period outweighing expected costs with a present value of $2.9 million.[3]

Benefits

A.4 The base case benefits of $5.6 million remain unchanged from those published in the consultation paper beginning at paragraph 4.5.

Costs

A.5 The Authority has estimated implementation costs for the three affected owners of offered wind farms, the system operator, NZX (as WITS manager and clearing manager), and the Authority itself. The implementation costs are one-off costs and are modelled to arise prior to any benefits flowing from the proposal. The Authority has also estimated increased operational costs to those parties. The results are shown in the following table.

Costs of the proposal

Party	Initial costs ($)	Operational annual costs ($)	Information used
Wind farm owners (total)	900,000	60,000	Authority estimate
System operator	879,000	0	Based on a report provided by the system operator
NZX Limited	415,100	0	High level costs provided by NZX
Authority	50,000	5,000	Authority estimate
Total	**2,244,100**	**65,000**	

A.6 These costs have a present value of $2.9 million assuming a 6 % discount rate and operational cost flows over a 15 year period.

[3] The effect of rounding these figures to the nearest $0.1 million is that the reported value of benefits minus the reported value of costs may not exactly equal the reported value of net benefits.

Sensitivity analysis

A.7 ***To a higher SRMC assumption:*** The Authority considers that an SRMC of $10/MWh is a reasonable figure to use as representative of all wind farms in aggregate. However, the Authority has some indications from wind farm owners that a higher SRMC figure might also be reasonable. Using a SRMC of $15/MWh would more than double the benefits. The benefits would increase from $5.6 million to $12.5 million. The costs would remain the same at $2.9 million, so net benefits would increase from $2.8 million to $9.6 million.

A.8 ***To discount rate:*** Even a substantially higher discount rate of 10 % would not eliminate the positive net benefits. The net benefits would fall from $2.8 million to $1.7 million.

A.9 ***To project life:*** Even if the benefits and (ongoing annual) costs flowed for only 7 years (rather than 15 years) the net benefits would still be positive. Net benefits would fall from $2.8 million to $0.6 million.

A.10 ***To growth in offered wind capacity:*** Using An annual growth rate of 3.5 % in offered wind capacity (rather than the 0 % used in the base case) would increase the net benefits from $2.8 million to $4.4 million.

A.11 ***To a more conservative assumption about the flexibility of non-wind generation owners:*** Our base case analysis assumes that non-wind generation owners respond in a relatively flexible way to the scheduled withdrawal of wind generation. This flexibility is broadly comparable with generators' observed flexibility responding to predictable intra-day demand variations. A more conservative assumption would be that non-wind generation owners replace withdrawn wind generation in a less flexible way. They can replace withdrawn wind generation only from their observed final offers in the relevant trading period. If this was the case, the net benefits from the proposal would be negative (-$0.6 million) for an assumed wind SRMC of $10/MWh. However, the net benefits would remain positive if we combined this assumption with a wind SRMC of $15/MWh (net benefits of $1.7 million) or with an assumed 3.5 % per annum growth in wind capacity (net benefits of $0.1 million).

.