Wholesale Advisory Group

Wind generation offers

Recommendations Paper

By the Wholesale Advisory Group

June 2016

Note: This paper has been prepared for the purpose of making recommendations to the Electricity Authority Board. Content should not be interpreted as representing the views or policy of the Electricity Authority.

984121-5

Contents

Figures

The Wholesale Advisory Group

The members of the WAG, as at the date of the publication of this paper, are:
John Hancock (Chair)
Phillip Anderson
Neal Barclay
John Carnegie
James Collinson-Smith
Stephen Drew
Graeme Everett
Alan Eyes
Chris Jewell
Stephen Peterson

Electricity Authority request

The Electricity Authority (Authority) has asked the Wholesale Advisory Group (WAG) to review the way in which:

a) wind generation is integrated within scheduling and dispatch arrangements

b) wind generators contribute to determining market prices.

The purpose of the review is to ensure that wind integration within scheduling and dispatch arrangements is consistent with the Authority's objective.

2 Introduction

2.1.1 On 8 April 2015, the Authority decided to discontinue an investigation into an alleged breach of clause 13.9(b) and clause 13.17(3) of the Electricity Industry Participation Code 2010 (Code) by Trustpower Limited (Trustpower). Transpower had alleged that Trustpower did not update its offers for its Tararua wind farm when generation at the wind farm was withdrawn for commercial reasons when prices were low.

2.1.2 The withdrawal of generation caused security concerns for the system operator with the sudden loss of 80 MW of generation. Trustpower denied that it actions breached the Code. The reason for the Authority's decision to discontinue the investigation was that the relevant Code obligations were ambiguous. The Authority noted that a Code amendment would be appropriate to clarify obligations relating to wind offers and the ability of a wind generator to withdraw its generation.

2.1.3 At the Board's meeting on 26 June 2015, Authority staff put forward a proposal to publish a consultation paper on various amendments to generation offer provisions in the Electricity Industry Participation Code 2010 (Code). The main issue in that paper was a proposal to shorten gate closure. The paper also included a proposal to insert a new Code provision providing that wind generators must not intentionally reduce generation significantly without giving at least 1 hour notice. This would have addressed the circumstances of the alleged breach described above. However, the Board asked Authority staff to withdraw that component of the proposal from the consultation paper and to undertake a wider review of the full set of offer requirements for wind generators.

2.1.4 In September 2015, the Authority invited the WAG to review arrangements for wind offers, scheduling and dispatch, and the way in which wind generators contribute to determining market prices. This paper presents the WAG's recommendations following its considerations.

2.1.5 The paper is set out as follows:

a) Section 1: Introduction, which includes projections for future wind generation capacity in New Zealand (below)

b) Section 2: A short description of current arrangements for wind offers

c) Section 3: Description of the two problems that the WAG has identified with wind offer arrangements

d) Section 4: Description and indicative quantification of the benefits available from resolving the identified problems

e) Section 5: Options for addressing the problems

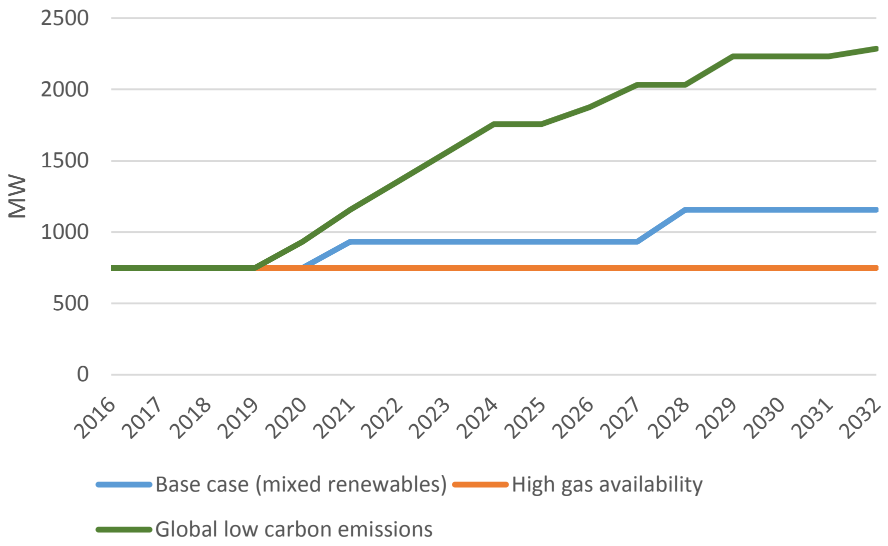
f) Section 6: The WAG's considerations and evaluation of the options

g) Section 7: The WAG's conclusion and recommendations.

Projections of wind capacity build

2.1.6 At present there is 661 MW of offered wind generation in New Zealand.[1] There is a high degree of uncertainty about investment in wind generation over the next 10 to 20 years. This uncertainty can be seen in the range of wind capacity build incorporated in the draft Electricity Demand and Generation Scenarios (draft EDGS) prepared by the Ministry of Business, Innovation and Employment (MBIE) in 2015. The base case ("mixed renewables") scenario for wind capacity build is shown in Figure 1 below along with two other scenarios that illustrate the range of uncertainty included in the EDGS.[2]

Figure 1: Projections for offered wind capacity (MW)



2.1.7 In the year 2032 (16 years in the future), the three projections of offered wind capacity are:

a) 748 MW for the high gas availability scenario

b) 1156 MW for the base case (mixed renewables) scenario

c) 2286 MW for the global low carbon emissions scenario.

[1] This total comes from generators' own descriptions of the capacity of their wind farms and excludes Flat Hill, which is not an offered wind farm.

[2] Refer to http://www.mbie.govt.nz/info-services/sectors-industries/energy/energy-data-modelling/modelling/electricity-demand-and-generation-scenarios/draft-edgs-2015. The present total connected wind capacity shown here is 748 MW. This includes both offered and unoffered wind generation.

3 Current arrangements for wind offers

3.1.1 When wind generators offer their plant into the market they are required to offer their generation in a single band. (Most other generators can offer in multiple bands at various different prices). The single band must have:

a) a price of $0.01/MWh (or $0.00/MWh if the wind generator has must run dispatch rights)

b) a quantity based on the wind generator's forecast of what it expects to be able to generate.

3.1.2 Offers must be in place at least 36 hours ahead. However, within the last 2 hours prior to the beginning of the trading period, the wind generator is required to revise their offer using a persistence-based methodology (or some other methodology approved in writing by the Authority). A persistence-based methodology is one based on current output of the wind farm.

3.1.3 Although wind generators receive dispatch instructions, they are not normally obliged to comply with dispatch instructions. An exception is where the system operator flags the dispatch instruction to indicate that the dispatch instruction is issued to manage a "system constraint".

4 The WAG has identified two problems

4.1.1 The WAG has identified two problems which it would be useful for the Authority to address:

a) the Code does not clearly prohibit non-notified (or inadequately notified) withdrawal of wind generation

b) there is no clear mechanism for economic withdrawal of wind generation.

4.1.2 The WAG has also considered potential problems related to incentives to forecast wind generation but has concluded that they do not warrant further consideration at this time.

There is no clear mechanism for economic withdrawal of wind generation

4.1.3 There is no clear mechanism within the Code for a wind generator to withdraw its generation for commercial reasons: that is, to generate less energy than the wind resource would allow. Consequently generators are, in general, not withdrawing wind generation when prices are low. This is likely to result in some productive inefficiency.

4.1.4 From an economic perspective it would be optimal if wind generators withdrew their plant when the price is below the short run marginal cost (SRMC) of the wind generation. A wind farm may have a significant, positive SRMC. Maintenance requirements will be a major driver of SRMC. Wear and tear on moving parts means that various maintenance procedures will be required more frequently on generating turbines compared with turbines that are spilling wind. This is likely to be true regardless of the nature of the generator's maintenance contract: that is, even if the generator's payments to its maintenance contractor do not depend on the amount of electricity generated. Viewed from a whole-of-system economic perspective, the contractor will still need to use more resources to maintain turbines that have been generating more.

4.1.5 Although most wind generators do withdraw wind from time to time for various reasons, it appears that wind generators do not in general withdraw generation in response to low price expectations (economic withdrawal). One exception is that Trustpower has sometimes withdrawn generation, although it appears this has happened very infrequently.[3] One generator notes that it sometimes engages in a process called "wind capping" in which wind generation is prevented from rising above its persistence forecast, but this stops well short of being "fully fledged" economic withdrawal.

4.1.6 The WAG has sought to understand why there appears to be a reluctance to engage in economic withdrawal. Generators have reported concerns that economic withdrawal of wind generation might be:

a) ***In breach of Code provisions.*** The most problematic provision appears to be clause 13.17(3)(a) which provides for wind farms to submit revised offers (in the last two hours before the beginning of the trading period) based on a persistence model. The wording of this provision may have created some uncertainty for generators. The Authority has already decided to change this provision[4] to clarify that a persistence model takes into account any expected changes in turbine availability and capability. The revised provision is expected to come into force in late 2017 or early 2018. More details of the existing provision and the incoming provision are set out in Appendix A.

b) ***Inconsistent with the spirit of the wind provisions in the Code:*** One view is that the wind provisions in the Code establish a "deal": wind farms are free to inject as much electricity as the wind resource will support, but the "quid pro quo" is that they can't withdraw generation when prices are low. The WAG's view is that there is no such unwritten expectation, and that preventing economic withdrawal is likely to be inefficient.

---

[3] Trustpower's withdrawal of generation on 21 May 2014 was the subject of an alleged breach, and an investigation by the Authority. The Authority decided to discontinue the investigation because it found that the Code obligations for an intermittent generator to revise its persistence offers are ambiguous.

[4] Refer to the decision paper titled *Shortened gate closure and revised bid and offer provisions* (4 November 2015) and available at https://www.ea.govt.nz/development/work-programme/wholesale/bid-and-offer-provisions-of-the-code/consultations/#c15415.

4.1.7 If generators are being discouraged from engaging in economic withdrawal of wind, the market may not be achieving least cost scheduling and dispatch. There may be some benefits from establishing a clear process for economic withdrawal to facilitate least-cost generation to meet demand.

The Code does not clearly prohibit non-notified (or inadequately notified) withdrawal of wind generation

4.1.8 On 21 May 2014 Trustpower withdrew 30 MW of wind generation from the Tararua wind farm over the course of 4 minutes, and around 12 minutes later withdrew a further 50 MW of generation within one minute. These reductions had not been signalled through offers, nor was any prior notice given to the system operator. This event was the subject of an alleged Code breach and an investigator was appointed. During the settlement process, the parties agreed that the Code was ambiguous. If notice of such withdrawals was needed as a matter of policy (either in the form of an offer revision or as telephone notice to the system operator) then this could be achieved by amending the Code, as long as the system operator's security concerns were managed until the Code amendment was in force.

4.1.9 The system operator has advised the WAG that its security issues were:

a) the potential impact on system frequency from plant ramping quickly

b) the potential impact on system voltage[5]

c) the potential reduction in the accuracy of forward looking schedules and consequential impact on the usefulness of those schedules for security checking.

4.1.10 The WAG understands that the system operator's concerns have been managed in this interim period through an informal agreement with Trustpower such that Trustpower will:

a) provide 5 minutes' notice of any similar economic withdrawal of wind, and

b) limit the rate at which the wind farm is ramped in those circumstances.

4.1.11 Following introduction of the informal agreement, Trustpower has not withdrawn wind generation without giving the agreed period of notice. The WAG understands that withdrawals using the notice period have been made on only two occasions between the date on which the informal agreement commenced and the beginning of April 2016. The WAG notes that low prices have been emerging relatively infrequently over that period.

[5] The impact is from the reduction in imported Mvars (linked to MW output), the Ferranti effect, and /or interactions with the Haywards RPC switching filters.

4.1.12 The informal agreement deals with the system operator's most pressing concerns by providing an opportunity for the system to be re-dispatched ahead of the wind withdrawal to manage the loss of generation. However some concerns remain. Wind withdrawal with 5 minutes' notice does not give the system operator sufficient time to conduct its usual security-checking process taking into account the new information. In addition the very short notice period provides no opportunity for other participants to respond by revising their offers. This could result in sub-optimal scheduling: that is, a failure to meet demand at least cost.

4.1.13 From a policy perspective, consistency with the offer obligations for other generators suggests that large changes to an offered generator's scheduled output that are discretionary and within the control of the generator ought to be achieved by revising offers so that the action can be incorporated into schedules. Offer revisions would normally have to occur prior to gate closure.

Incentives to forecast wind generation do not warrant further consideration at this time

4.1.14 Another potential problem relating to wind generation offers is that there may not be good incentives in place for wind generation forecasting[6]. Wind generators may not optimise the trade-off between the cost of forecasting and the benefits to be gained from it in terms of better market scheduling.

4.1.15 In particular, the WAG considers that existing forecasting can clearly be improved using more sophisticated methods and better information. If the information available for scheduling is poor, opportunities for reducing the overall cost of generation to meet demand may be missed.

4.1.16 However, the WAG considers that this potential problem does not warrant further consideration at this time. Identifying ideal arrangements for wind forecasting involves complex issues, and significant changes would require high implementation costs. Given the relatively small quantity of wind generation in New Zealand (compared with larger overseas jurisdictions), and the uncertainty of further wind build, the WAG considers it is not the right time to consider these issues further. While the quality of wind forecasting quality could be improved, the benefits of improving the quality would be small relative to the cost of solutions.

4.1.17 The WAG notes that shortened gate closure for most generators is expected to be implemented in late 2017 or early 2018. Gate closure currently occurs two hours ahead of the trading period for most wind farms, but will change to one hour. This will improve the ability of flexible generators to respond to changes in wind

[6] In New Zealand, each wind generator forecasts its own generation and uses that forecast as its offer quantity. Market schedules are produced on the basis of these "decentralised" forecasts. In most overseas jurisdictions the system operator prepares the forecast of wind generation for each wind farm (assisted by obtaining certain information including real time information and turbine availability intentions from the wind farms) with that "centralised" forecast being used in market schedules.

generation. This could reduce the benefits available from improving wind forecasting (because some of those benefits will already have been captured by shorter gate closure).

Circumstances have not changed substantially since previous investigations into arrangements for wind forecasting

4.1.18 In 2010 the Electricity Commission considered options for wind forecasting and market integration, including the possibility of moving to central forecasting of wind. The Commission recognised that the existing decentralised approach to wind forecasting did not provide strong incentives for accurate forecasting, but it decided to retain decentralised forecasting while continuing to monitor the accuracy of those forecasts. The alternative of moving to a centralised forecasting regime (as in most overseas jurisdictions) would have been prohibitively expensive to implement.

4.1.19 In 2014 the system operator commissioned a report on options for wind generation forecasting, including the possibility of the system operator preparing a central forecast. While the report has not been published, the system operator decided not to pursue the preparation of a central forecast. The WAG understands that the expense of implementing a central forecast was again considered prohibitive.

4.1.20 The amount of offered wind generation has increased by only 60 MW (to 661 MW) since the commissioning of Te Rere Hau and Te Uku wind farms in 2011. That increase was due to Meridian's 60 MW Mill Creek wind farm commissioned in 2014. There is at present no firm commitment to build further offered wind generation. Consequently the WAG considers the situation has not changed substantially from what was known to the system operator in 2014, and even from what was known to the Electricity Commission in 2010.

5 Benefits from resolving the two identified problems

Benefits from facilitating well-signalled economic withdrawal of wind

5.1.1 The WAG has attempted to quantify the dollar value of the benefits from resolving both of the two identified problems. These are the benefits of facilitating economic withdrawal of wind but in a way that is well signalled through offers submitted prior to gate closure.

5.1.2 The benefits of facilitating well-signalled economic withdrawal of wind will depend on the size of the short run marginal cost (SRMC) for wind. This may vary from one wind farm to another, and across different wind conditions.

5.1.3 The WAG has received an indication from the owner of a small wind farm that the SRMC may be between $20 and $30/MWh, with the higher end of that range applying during strong and turbulent wind conditions. The owner of a larger wind farm has suggested that SRMC could be between $10 and $15/MWh.

5.1.4 In order to obtain a broad indication of the size of the problem, the WAG determined a single “point estimate” for wind SRMC. A figure of $10/MWh seems most appropriate. It recognises that largest sites will be the most important in any cost-benefit analysis.

5.1.5 The resulting estimates of the economic benefits of facilitating economic withdrawal of wind should be used with caution. They can be only broadly indicative. In particular the analysis:

a) used a number of proxy measures which could be subject to criticism

b) made some substantial simplifications

c) sometimes used a small amount of data for convenience (to save time) when a larger amount of data was available

d) assumed that maintenance cost depend on the amount of electricity generated, when some sites use fixed price maintenance contracts.

5.1.6 A summary of the steps taken in the analysis is set out in Appendix B.

5.1.7 The WAG estimates that the present value[7] of the economic benefits of facilitating well-signalled economic withdrawal of wind generation is $3.6 million.

The benefits would be less if only 5 minutes’ notice of wind withdrawal was provided

5.1.8 It might be possible to advocate that wind generators ought to be able to withdraw wind with only 5 minutes’ notice to the system operator. The argument is that non-wind generators can withdraw with little notice, so wind generators should be able to do the same (a “level playing field” argument). The argument relies on the observation that non-wind generators can offer in such a way that they can be dispatched up or down based on real time market conditions (thus they can “withdraw with little notice”). This argument is discussed and challenged in Appendix C.

5.1.9 If Code provisions encouraged economic withdrawal of wind with only 5 minutes’ notice to the system operator, the benefits would be lower than described above. There are two reasons for the benefits being lower:

a) It would be harder for the system operator to manage security.[8] The WAG has not quantified the dollar value of this effect.

---

[7] When calculating the present value, the discount rate is assumed to be 8 percent and the stream of benefits flows at the end of each of 15 years.

b) Putting security issues to one side, the benefits that would arise from facilitating economic withdrawal of wind generation (demand can be met at lower overall cost) would be less because non-wind generators would have less flexibility to increase their generation to compensate for the withdrawn wind generation. The WAG estimates that the present value of the benefits would decline by $2.1 million due to this effect. The steps used to estimate this figure are described in Appendix B.

6 Options

6.1.1 Two key options to address the problems are:

a) a proportional solution that targets the problems while avoiding substantial system changes

b) moving to a more sophisticated wind integration system such as in Australia's National Electricity Market.

6.1.2 A third option would be to make no changes – that is, to retain the status quo. The "no change" option is considered first below.

Option 1: No change (status quo)

6.1.3 Under this option the Authority would not make any further changes to the Code and would keep in place all existing arrangements, including the informal agreement between Trustpower and the system operator about the management of the Tararua wind farm.

6.1.4 A package of Code amendments will come into force when shortened gate closure is implemented. One of the key changes is described in Appendix A. The Code amendments could help to make generators more comfortable about engaging in economic withdrawal of wind generation. This could have positive effects if notice is given or potentially negative effects if no notice is given. The Code amendments seem unlikely to prevent wind farms withdrawing without notice.

Option 2: Proportional solution

6.1.5 This solution aims to address the problems in a manner proportionate to the problems identified and avoiding implementation costs that would outweigh the potential benefits.

---

[8] Since the wind withdrawal would not be known well in advance, that information could not be included in the system operator's normal processes for security assessments, determining security constraints, and assigning frequency keeping duties. Many of the inputs to real-time dispatch come from schedules run earlier. For example the "n-1 security constraints" and information about reserve requirements are determined from the non-response schedule run around 20-30 minutes prior to real time. It is plausible that wind withdrawal carried out with 5 minutes' notice would cause the security constraints and reserve requirements used in dispatch to be sub-optimal. Similarly, the frequency keeping selection and security assessments are based on schedules run well before real time.

6.1.6 The proportional solution would amend the Code to:

a) **Ensure offers reflect intentions for availability.** The amendment would clarify that all wind offers, including persistence-based offers, must reflect intentions in relation to turbine availability and in relation to any other turbine settings that would reduce turbine output below the full amount supported by the expected wind resource. The amendment would avoid imposing onerous obligations by focusing only on large changes to MW availability, above a de minimis in the range of 20 -30 MW.

   Require notice of withdrawal prior to gate closure. The amendment would prevent a wind generator deliberately reducing generation without that being consistent with the MW availability incorporated into its offers prior to gate closure. Again, this provision would be focused only on large changes (above the de minimis), subject to no unintended consequences being identified for existing plant. Exceptions could be provided for withdrawals made for reasons of personnel and plant safety. An exception could also be provided to allow a wind farm to be withdrawn as storm conditions arrive if this helps the wind farm owner to restart the wind farm more quickly after the storm passes.

b) **Require information retention/disclosure.** The amendment would require offered wind farms to retain information about real time MW availability (e.g. turbine availability and potentially some turbine settings), and the forecast of that MW availability which has been used to prepare offers. This information could be used to monitor compliance.

Option 3: A more sophisticated wind integration system

6.1.7 Another broad option available to the Authority would be to move to a substantially more sophisticated wind integration system. Australia's National Electricity market provides a model for a sophisticated wind integration system, including advanced central forecasting of wind generation. It would be prohibitively expensive to move the whole way to the Australian wind integration system, but the option described here would be a substantial move in that direction.

6.1.8 It is useful to note that while New Zealand has 661 MW of offered wind capacity, Australia's National Electricity Market has 3,669 MW of installed registered wind capacity.[9] A larger sized industry may justify a more formalised approach to wind integration.

6.1.9 Under option 3, wind farms would provide a (decentralised) "unconstrained wind generation forecast" which is a forecast of generation assuming all turbines are

[9] Source: http://energy.anero.id.au/wind-energy/2016/march/31

fully available. This unconstrained forecast would be updated using new meteorological information as it comes to hand (e.g. every six hours). In the last two hours before the beginning of the trading period, a persistence-based methodology (or some other, better, methodology approved by the Authority) would be to develop the unconstrained forecast.

6.1.10 A wind generation offer would contain up to five bands. As for non-wind generators, each band would have both a quantity (in MW) and a positive (or zero) price associated with it. Prices would be in increasing order so that the offer is an "upward sloping" supply curve with up to five tiers. The total offered capacity would always reflect the *nameplate capacity* of the wind farm (but the wind farm would not be scheduled or dispatched above its unconstrained forecast – see below). The incentives would encourage wind farms to offer their generation in a way that reflects the SRMC.

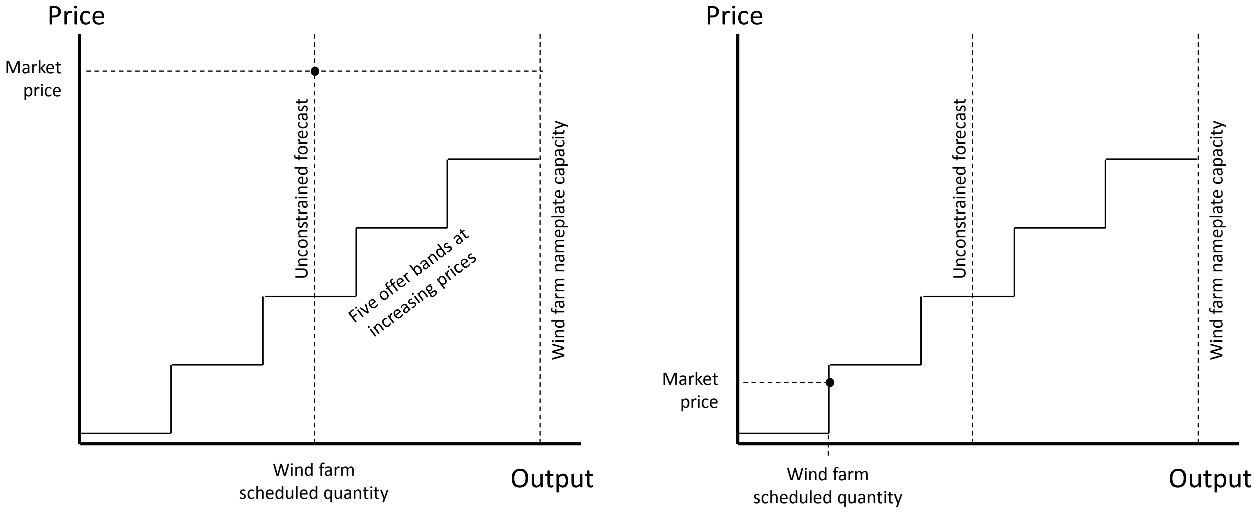
6.1.11 The wind farm would be scheduled in pre-dispatch schedules (such as the price response schedule and the non-response schedule) at the lower of:

a) its unconstrained forecast and

b) the level defined by its offer and the market price.

6.1.12 This is illustrated in Figure 2. Since wind farm offer prices will usually be quite low, the wind generator would normally be scheduled at its unconstrained forecast (example 1 in Figure 2). However, if market prices were low, we could expect the generator to be "scheduled back" on economic grounds, depending of course on the wind farm's offer prices (example 2 in Figure 2).

Figure 2: How a wind farm would be scheduled under option 3



Example 1: The wind farm generates as much as it is able given the wind resource. It is scheduled at its "unconstrained forecast".

Example 2: The wind farm is scheduled to generate less than would be supported by the wind resource based on the prices in the offer bands. It is scheduled to generate from a low priced band, but not from higher-priced bands.

6.1.13 Wind farms would not be obliged to comply with dispatch (so could generate based on the available resource) unless they were dispatched down for economic reasons (example 2 in Figure 2).

6.1.14 The final pricing schedule would use a similar approach to that described in Figure 2. If the wind farm had not been "scheduled back" during the trading period, the metered output of the wind farm would be used in place of the "unconstrained forecast". It would be possible for wind farms to set the market price.

7 The WAG's considerations

Option 3 likely to have negative net economic benefits

7.1.1 In setting out the broad design of option 3 the WAG has tried to keep implementation costs down. Even so, the WAG expects the costs of implementing option 3, both for the system operator and for participants, could be in excess of $8 million.[10]

7.1.2 The present value of the potential benefits of moving to option 3 could be around the indicative figure of $3.6 million. The WAG is confident that option 3 could not be justified on cost-benefit grounds, especially since most of these benefits would be achieved by option 2 (see below).

[10] This is not based experience with similar large scale projects that involve changes to scheduling and dispatch systems.

Option 1 does not resolve the identified problems

7.1.3 The two identified problems are:

a) there is no clear mechanism for economic withdrawal of wind generation

b) the Code does not clearly prohibit non-notified (or inadequately notified) withdrawal of wind generation.

7.1.4 The Authority could decide to take no further action to address these problems. If the Authority adopted this approach:

a) it might not gain the available efficiency benefits associated with notified economic withdrawal. These benefits have been indicatively estimated at a present value of $3.6 million. A Code amendment is scheduled to come into force in late 2017 or early 2018 when shortened gate closure is implemented. One of the changes introduced by that Code amendment affects the wind persistence forecasting provision (refer to Appendix A). This may make it more likely that wind farms will engage in economic withdrawal, but this remains uncertain.

b) it would be relying on the good will of wind farms not to withdraw wind generation without notice (or with only 5 minutes' notice). If this behaviour were to occur it is possible that there could be severe consequences for the security of the power system (especially if no notice at all is provided).

7.1.5 Option 1 is not recommended because it does not clearly resolve the identified problems. It may fail to capture significant efficiencies from facilitating economic withdrawal of wind with notice. It also fails to address significant security concerns.

Option 2 is likely to have positive net economic benefits

7.1.6 Option 2 is expected to have low costs for implementation and ongoing operation: probably less than a present value of $0.5 million. The largest component of those costs may be the costs imposed on wind farms due to the need for systems to retain information. They would be required to retain information about real time turbine availability (including potentially some turbine settings), and about the forecast of that availability, which has been used to prepare offers. Many wind farms may do this already. This information could support the monitoring of compliance.

7.1.7 The WAG expects that offered wind farms will not need to revise their systems for determining and submitting offers. However, it is possible that some changes may be required in some cases to establish a more explicit and possibly automated connection between MW availability (e.g. turbine availability) and the offered quantity. The Authority should endeavour to understand those changes and mitigate the need for expensive changes where possible.

7.1.8 The benefits of option 2 have been estimated indicatively at a present value of $3.6 million.

7.1.9 The WAG considers that the cost-benefit analysis indicates the positive net benefits of option 2. However, even if the CBA is not regarded as conclusive, the WAG considers that option 2 is:

a) small scale: it does not commit the Authority to an expensive path for market development

b) reversible: it would not be difficult for the Authority to adopt a different approach if the proposed approach proves to be unsuccessful at resolving the problems

c) scalable: if large amounts of offered wind capacity are added to the system and a more sophisticated wind integration system is required, the proposed approach is likely to be reasonably consistent with, and would not create an impediment to, a move in that direction.

7.1.10 The WAG considers that the relatively low cost proposal complements the Authority's plans to shorten gate closure to one hour for most generators. Shortening gate closure will allow wind generation forecasts to be better at gate closure (being closer to real time), and will allow greater flexibility for non-wind generators in scheduling their plant. It would not be a good time to be making further expensive changes to scheduling systems in pursuit of benefits that may well be captured already through the gate closure changes.

When might a move to a more formalised wind integration system become justifiable in New Zealand?

7.1.11 An interesting question is how much wind generation would be needed in New Zealand to justify a move to a more formal wind integration regime, including central forecasting along the lines of the system used in the NEM? The WAG has not considered in any detail the potential benefits of that kind of system. The WAG has simply noted:

a) previous reviews in New Zealand, which have concluded that decentralised forecasting should be retained

b) that circumstances have not changed substantially since those reviews.

7.1.12 It is useful to note that Australia's NEM has 3,669 MW of registered wind capacity compared with New Zealand's 661 MW of offered wind capacity.

7.1.13 Option 3 outlined in this paper provides a “cut down” version of a NEM-like regime that retains decentralised forecasting and minimises system changes where possible. When might such a cut down approach become justified in New Zealand?

7.1.14 We can give only an indicative answer to this question. If the benefits of option 3 are $3.6 million and the costs are $8 million, then we would need 2.2 times current wind capacity to deliver a small positive net benefit. That is 1,450 MW of offered wind capacity. Under the most “pro-wind” scenario in MBIE’s EDGS work (the “global low carbon emissions” scenario), that level of wind capacity would be achieved in the year 2023. Under the base case scenario it would be achieved in the year 2043. (Refer to Figure 1). However, most of the benefits of option 3 can be captured by the cheaper option 2, so this would suggest a much later date at which option 3 could be justified.

8 Conclusion and recommendations

8.1.1 The WAG recommends the Authority address the identified problems by considering amendments to the Code to:

a) ensure offers reflect intentions for availability (focus only on large changes to intentions that result in changes in output greater than 20 - 30 MW)

b) require notice of the withdrawal of wind generation prior to gate closure (again focus only on large withdrawals of more than 20 - 30 MW)

c) require wind farms to retain information about their MW availability and the forecasts of that availability that have contributed to offers.

8.1.2 The WAG considers this would result in a positive net present value of around $3.1 million. The costs of implementing and operating the changes are estimated at $0.5 million while the benefits are estimated at $3.6 million.

8.1.3 The changes would be consistent with the Authority’s statutory objective and Code amendment principles.

Appendix A Code provisions - persistence-based forecasts for wind generation

A.1 The existing Code provides:

13.17 Offers may be revised or cancelled

…

(3) Despite subclauses (1) and (2), and subject to clauses 13.19 and 13.97 to 13.101, each **intermittent generator** must submit any revision to the **offer** price at least 2 hours before the beginning of the **trading period** in respect of which the **offer** was made. In addition, the **intermittent generator**—

(a) must revise the quantity of each **offer** made under this subclause during the 2 hours immediately before the **trading period** in respect of which the **offer** is made, in order to comply with clause 13.9(b). Each revised **offer** must be based on a persistence model using actual output from the **intermittent generating station** at the time the revised **offer** is submitted, unless otherwise agreed with the **Authority**; and

(b) may cancel any **offer** by notice in writing to the **system operator**. Any such cancellation may be made up to 30 minutes before the beginning of the trading period in respect of which the offer was made.

A.2 The Authority has decided to restate this provision as follows:[11]

13.18A Intermittent generators to provide revised offers

(1) During the 2 hours immediately preceding the **trading period** to which an **offer** relates, each **intermittent generator** must submit revised offers in respect of **MW** offered to the **system operator** at a frequency of at least 1 revised **offer** per **trading period**.

(2) A revised **offer** submitted under subclause (1) must be based on a persistence model, unless otherwise agreed with the **Authority**.

(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

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

[11] Refer to the decision paper titled *Shortened gate closure and revised bid and offer provisions* (4 November 2015) and available at https://www.ea.govt.nz/development/work-programme/wholesale/bid-and-offer-provisions-of-the-code/consultations/#c15415.

A.3 This new provision is part of a package of Code amendments that will come into force at the same time as the system operator implements reduced gate closure. The date at which the package of Code amendments will come into force is currently being negotiated with the system operator. The Authority expects it will come into force in late 2017 or early 2018.

Appendix B Analysis of the benefits of economic withdrawal of wind

The key steps in the analysis

B.1 The end result of the analysis in this appendix is that the present value of the economic benefits of facilitating well-signalled economic withdrawal of wind generation (when market prices move below the wind farm's SRMC) is estimated at $3.65 million. This assumes that sufficient notice of the withdrawal is given to allow non-wind generators to revise their offers in response to the withdrawal.

B.2 This appendix explains how that figure is calculated.

B.3 The analysis assumes a fixed SRMC for wind farms of $10/MWh. The WAG is aware that SRMC will be different for different wind farms and may vary for a wind farm over time. The analysis will remain valid as a broad indicator of the economic benefits as long as $10/MWh is a reasonable measure of the average SRMC over time and over all wind farms. The analysis could be re-run reasonably easily using a different SRMC value. The analysis could also be adapted to allow a different SRMC to be specified for each wind farm.

B.4 The key steps in the analysis are:

- (a) Determining the observed historical private benefits available to wind farms from avoiding generating electricity when the market price is below SRMC
- (b) Projecting the private benefits that could be expected in future years
- (c) Determining the proportion of the projected private benefits that is an economic benefit. This involves:
  - (i) illustrating diagrammatically the difference between the private benefit from a wind farm generating when the market price is below SRMC, and the economic benefit to the economy as a whole from that action. This shows that the economic benefit depends on the assumed slope of the supply curve for non-wind generation
  - (ii) determining the slope of the supply curve for non-wind generation
  - (iii) using that estimated slope, determining a factor (between 0 and 1) representing the proportion that the economic benefits can be expected to form of private benefits
  - (iv) applying that factor to determine projected annual economic benefits.
- (d) Determining the present value of the projected stream of economic benefits.

B.5 At the end of this Appendix we modify the analysis to determine the reduction in these benefits if only 5 minutes' notice of wind withdrawal is given.

Observed historical private benefits

B.6 The WAG's analysis began with the following data for each offered wind farm (excluding Mahinerangi12), from the beginning of the wind farm's construction (the earliest data dates back to 2004) through until the end of October 2015:

(a) half hour settlement prices at the wind farm's node

(b) and half hour output for the wind farm.

B.7 For each trading period and each wind farm a "loss" was calculated. This was determined as the amount by which price was below the SRMC (of $10/MWh), multiplied by output.[13] Wind farm capacity has increased substantially over time, so total annual losses have tended to increase correspondingly. Annual losses are highly volatile reflecting the volatility in the number of trading periods with very low prices. For example, in 2009 there were 2718 trading periods where the price at TWC2201 was below $10/MWh while in 2015 there were only 230 such trading periods.

B.8 The loss over the whole time period for all offered wind farms (excluding Mahinerangi) was $7.3 million over 15.8 TWh. This equates to an average loss of $0.46/MWh over all the energy produced by wind farms.

B.9 These losses are the potential private benefits available from avoiding generating from wind farms at those times.

Projecting annual benefits into the future

B.10 Assuming the present capacity of offered wind farms remains permanently in place, projected energy output from wind farms (excluding Mahinerangi) is projected to be 2.1 TWh per year. Projecting the historically observed potential private benefit rate of $0.46/MWh into the future allows us to project potential private benefits to wind farms (excluding Mahinerangi) of $0.98 million per annum.

B.11 Upscaling these benefits by 5.8% adjusts for the presence of the Mahinerangi wind farm. Annual potential private benefits from wind farms withdrawing generation when prices are below SRMC are therefore projected to be $1.04 million per year.

---

[12] The analysis excluded the Mahinerangi wind farm since output from the wind farm was not available. The Mahinerangi wind farm and the Waipori hydro scheme are metered together so that the wind farm output is not available separately.

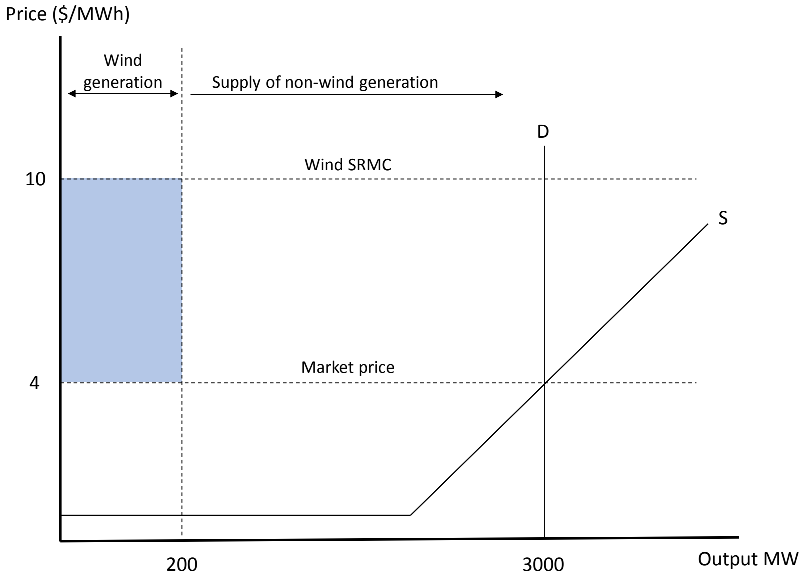
[13] The total loss is the sum over all wind farms and all half hours of wind farm generation in MWh * Max[0, ($10/MWh – nodal price at the wind farm)].

Determining the annual economic benefits

Potential private benefit and economic benefit

B.12 Figure 3 shows a conceptual diagram of the potential private benefit to a wind farm from withdrawing generation. The wind farm generates 200 MW. Demand is 3000 MW. The supply curve for non-wind generation is such that the price is below $10/MWh: say $4/MWh. The supply curve for non-wind generation is upward sloping.

Figure 3: Private benefit to wind farm from avoiding generating below SRMC



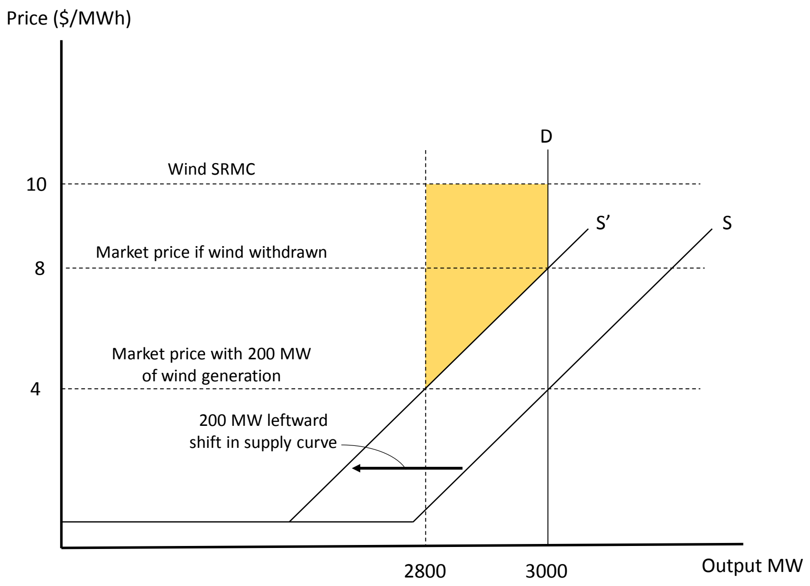
B.13 The potential private benefit available to the wind farm from withdrawing its 200MW of generation for this half hour trading period is 0.5 (since it is a half hour) * 200 MW * the amount by which the wind farm's SRMC exceeds the price it receives (the difference here is $6/MWh) = $600.

B.14 The economic benefits are different. They recognise that not all of the withdrawn 200 MW of wind generation will be able to be replaced at the market price of $4/MWh.

B.15 If the wind farm withdrew its 200 MW the effect would be to move the supply curve left by 200 MW. Suppose the market price would rise to $8/MWh in that case and that we can treat the supply curve as a straight line. Then the economic benefit from withdrawing the wind generation is illustrated as the shaded area in Figure 4. It is $400, which is 67% of the private loss.[14]

[14] The area of the upper shaded rectangle is 0.5 (since we are dealing with a half hour trading period) * 200 MW * $2/MWh = $200. The area of the shaded triangle (below the rectangle) is 0.5 (since we are dealing with a half hour trading period) * 0.5 * 200 MW * $4/MWh = $200. So the total area is $400.

Figure 4: Economic benefits from wind farm withdrawing generation below SRMC



B.16 The scaling factor (calculated in this example as 67%) converts the potential private benefits of withdrawing the wind generation into the economic benefits. The scaling factor will depend on the slope of the supply curve.

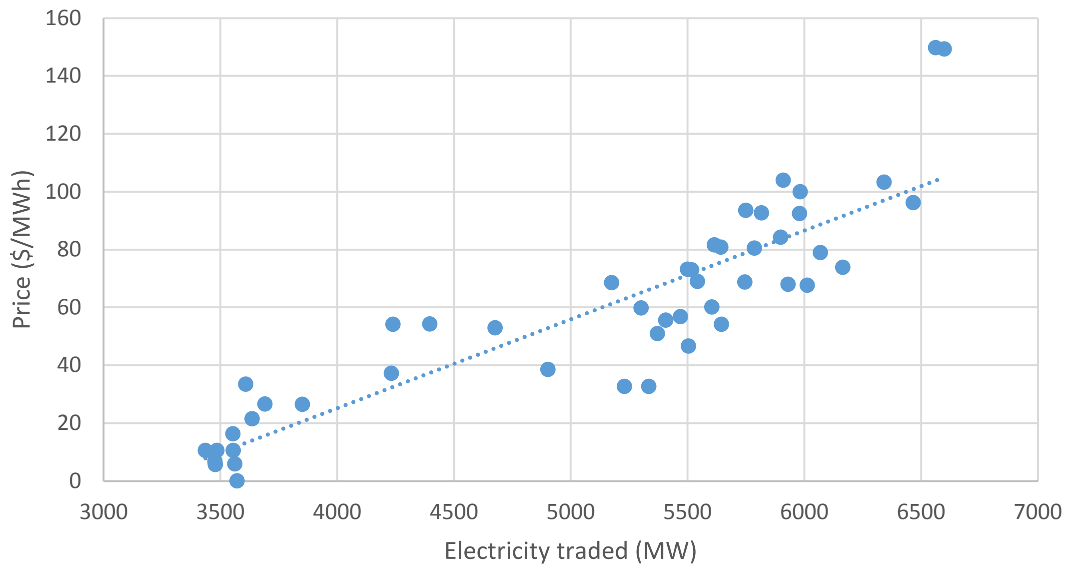
Estimating the slope of the supply curve

B.17 One way the analysis could proceed would be to look at the typical slopes of final offer curves, especially at low price levels. However, if notice of wind withdrawal is provided prior to gate closure, non-wind generators would have the opportunity to respond by changing their offers (they are not restricted to keeping the existing offers in place). In principle the supply curve slope should be flatter if we take account of this additional flexibility. (The typical slope of a final offer curve would be appropriate if we assumed that 5 minutes' notice of the withdrawal was provided). A proxy "flexible" supply curve could be obtained by plotting the equilibrium price and quantity for each of the 48 trading periods within a single day. This proxy supply curve would reflect generators' normal intra-day flexibility. That could be used as a proxy for the flexibility available if wind withdrawal is well-signalled.

B.18 The WAG examined data for a single day: Monday 26 May 2014. This date was chosen because it had a number of low priced trading periods in it. There were four trading periods that day with prices at Haywards below $10/MWh.

B.19 Each trading period was plotted on the diagram showing the market price (at Haywards) and the inferred demand (electricity traded). The results are shown in Figure 5. Simple regression analysis was used to reveal an implied supply curve: as more electricity is needed, higher prices are required to bring on the necessary supply.

Figure 5: Implied supply curve for a day



B.20 The slope of the regression line is 0.031. This suggests that if 10 MW of wind was withdrawn with a long period of notice to participants, prices could rise by an indicative $0.31/MWh.

Determining the scaling factor

B.21 For each of the four trading periods with prices below $10/MWh, the WAG observed actual wind generation and market prices and determined the potential private economic benefits available to wind farms from withdrawing the generation. The WAG then analysed the effect of moving the supply curve (with slope 0.031) to the left by the amount of wind generation in that trading period. For each trading period the dollar value of the economic benefit was determined. Over the fur trading periods combined, the economic benefits would have been 41 per cent of the private losses.

Projected annual economic benefits

B.22 Applying the scaling factor of 41 percent to projected potential private benefits gives projected annual economic benefits of $0.43 million.

Present value of the projected stream of economic benefits

B.23 Assuming these annual economic benefits flow at the end of each of 15 years, and assuming a discount rate of 8 per cent, the present value of the economic benefits of facilitating withdrawal of wind generation when prices are below $10/MWh is $3.65 million.

Modifying this analysis to determine the reduction in these benefits if only 5 minutes' notice of wind withdrawal is given

B.24 Assuming that wind was withdrawn without notice to other participants (e.g. with say 5 minutes notice to the system operator) then the missing wind generation would have to be replaced from existing non-wind generation offers. In this case it is appropriate to determine the slope of the supply curve from observing the slope of final offer curves near the equilibrium price when that equilibrium price is low.

B.25 Again, data from Monday 26 May 2014 was used. For each trading period in the day where the price (at Haywards) was less than $10/MWh, the final offers were constructed into a simple offer stack. Given the final price at Haywards, a notional level of demand was constructed (abstracting from electrical losses). We added 150 MW of notional demand (which models the effect of withdrawing 150 MW of wind) and read the price off the supply stack. We also subtracted 150 MW of notional demand and read the resulting price off the supply stack. In this way we determined the slope of the supply curve over a 300 MW range.

B.26 For the four trading periods that day where the price at Haywards was below $10/MWh the average slope of the supply curve was 0.071. A straight line supply curve with a slope of 0.071 would mean that if 10 MW of wind was withdrawn (with 5 minutes' notice to the system operator), prices would rise by $0.71/MWh.

B.27 The WAG then modelled the effect in each of the four trading periods of withdrawing available wind generation assuming that slope for the supply curve. (Wind generation was not withdrawn beyond the point at which prices would rise to $10/MWh). In this way an economic benefit could be calculated.

B.28 The economic benefits over the four trading periods totalled to 18 per cent of the potential private benefits.

B.29 Using the same methodology as above produces a present value of the economic benefits of $1.59 million. This is $2.06 million less than benefits calculated above.

Appendix C Economic withdrawal of wind with little notice

C.1 An argument might be made to prefer 5 minutes' notice (over the alternative of requiring notice prior to gate closure) on the grounds of maintaining a "level playing field" between wind farms and non-wind generation. The argument is that non-wind generators have the ability to withdraw generation very rapidly in response to unexpectedly low real time prices by using multiple offer bands. They can structure their offer in such a way that if prices in real time are unexpectedly low, the plant will be dispatched to a lower level of output. In contrast wind farms are required to offer their generation in a single band priced at $0.01 so the same technique is not available to wind farms.

C.2 The WAG applies the level playing field concept differently.

C.3 All generators should signal their intentions as far as reasonably possible prior to gate closure. This facilitates co-ordinated scheduling. However, if wind generators were required to specify at gate closure exactly what they would generate, they would not be financially viable because they cannot be certain of delivering on the forecast. It is well recognised internationally that the financial viability of wind generation requires that it be allowed to "float on the wind", producing more or less as the wind resource allows.

C.4 An inexpensive means of integrating wind into the grid was needed given the relatively small size of the New Zealand market. The requirement to offer wind generation in a single band priced at zero was a relatively low-cost way to integrate wind.[15] While this allowed wind farms to "float on the wind" (without expensive system changes), it was not intended to allow substantial non-notified wind withdrawal which is under the control and discretion of the wind farm. There is no reason to move away from the general rule in that case – that all generators should signal their intentions prior to gate closure.

C.5 The requirement to signal intentions prior to gate closure is not unique to wind.

(a) Non-wind generators typically make commitment decisions prior to gate closure based on their expectations of market conditions. Those non-wind generators can potentially suffer financial disadvantage if they get their commitment decision "wrong".

(b) Type B co-generators are also allowed to "float on their underlying production process" (they are generally exempt from dispatch compliance) and they are required to offer in a single band at zero.[16] They are required to comply with the normal offering processes. So if they intend to withdraw their generation for commercial reasons (as opposed to a physical plant

[15] A more formal but also more expensive approach to wind integration is typified by the approach used in Australia's National Electricity Market.

[16] More precisely, they are allowed to use up to two bands, but the bands must have prices of $0.00 and $0.01/MWh.

problem), they would be obliged to signal that as far as reasonably possible prior to gate closure.

C.6 If wind generators wanted the ability to economically withdraw by offering in multiple price bands while also "floating on the wind" (Australia's NEM achieves this), expensive system changes would be required. While the WAG recognises the attractions of such a system, its cost appears prohibitive at present given the benefits available in New Zealand's smaller market.