# Wind Offer Arrangements

## Consultation paper

Submissions close: 5pm on 7 November 2017

September 2017

Market Design

# Executive summary

The purpose of this paper is to consult with stakeholders on the Electricity Authority's (Authority) proposal to improve the offer arrangements for wind generators. Wind generation is described as "intermittent generation" in the Electricity Industry Participation Code 2010 (Code). The Authority's preferred option would allow wind generators to offer their generation to the spot market in up to five price bands like most other types of generators.

The issues identified with the current arrangements that require wind generators to offer their generation at $0.01/MWh or $0.00/MWh are:

(a) there is no clear mechanism for wind farms to withdraw generation when spot market prices are below their short run marginal cost (SRMC)

(b) there is no clear prohibition in the Code against a wind generator rapidly withdrawing generation from the spot market in real-time without providing any notice to the system operator.

The objective of the proposal is to enable wind generators to withdraw their generation in an efficient, centrally co-ordinated way when the spot market price is below their SRMC, and to prevent wind generators withdrawing large amounts of generation in ways that are not well co-ordinated.

The preferred option would:

(a) Require wind generators to submit offers in a new form with five offer bands rather than one. The form would also have a new field for a "forecast of generation potential" (in MW).

(b) Change provisions relating to wind generator'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 (RTD) schedules, to use the new offer information as an input.

(d) Require wind generators to comply with any dispatch instruction to generate below their potential level. If the dispatch instruction is to generate at their potential level, there is no dispatch compliance obligation.

(e) Prohibit wind generators from generating at a rate more than 30 MW below their final forecast of generation potential 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) Make constrained on (but not constrained off) payments to wind generators consistent with payments that are currently made to other types of generation.

The present value of the expected net benefits of the proposal is $2.9 million, assessed over a period of 15 years. This consists of benefits of $5.6 million less costs of $2.7 million. The benefits arise from more efficient use of resources by enabling lower-cost generation to be used to meet demand. The costs are predominantly implementation costs for wind generators and the system operator.

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# 2 What you need to know to make a submission

## What this consultation paper is about

2.1 The purpose of this paper is to consult with stakeholders on the Authority's proposal to amend the Code to allow wind generators to offer their generation in up to five price bands like most other generators. Wind generation is described in the Code as "intermittent generation".

2.2 The amendment would increase the efficiency of scheduling and dispatch to better align with the Authority's statutory objective. The amendment recognises that wind generators may have a positive SRMC that reflects predominantly wear and tear costs. It is efficient to allow a wind generator to withdraw generation when the market price is below that SRMC.

2.3 The amendment would change the form in which wind generators submit their offers. It would also modify the inputs into the various market schedules to incorporate the new structure of wind generator offers. Provisions would be added to prevent a wind generator withdrawing large amounts of generation without first having signalled that withdrawal through offers.

2.4 Section 39(1)(c) of the Electricity Industry Act 2010 (Act) requires the Authority to consult on any proposed amendment to the Code and corresponding regulatory statement unless the proposed amendment:

(a) is urgent, or technical and non-controversial; or

(b) is widely supported; or

(c) there has been adequate prior consultation.

2.5 Section 39(2) of the Act provides that the regulatory statement must include:

(a) a statement of the objectives of the proposed amendment

(b) an evaluation of the costs and benefits of the proposed amendment

(c) an evaluation of alternative means of achieving the objectives of the proposed amendment.

2.6 The regulatory statement is set out in Section 3 of this paper.

## How to make a submission

2.7 The Authority's preference is to receive submissions in electronic format (Microsoft Word) in the format shown in Appendix B. Submissions in electronic form should be emailed to submissions@ea.govt.nz with "Consultation Paper—Wind Offer Arrangements" in the subject line.

2.8 If you cannot send your submission electronically, post one hard copy to either of the addresses below, or fax it to 04 460 8879.

Postal address

Submissions
Electricity Authority
PO Box 10041
Wellington 6143

Physical address

Submissions
Electricity Authority
Level 7, ASB Bank Tower
2 Hunter Street
Wellington

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

(a) indicate which part should not be published

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

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

2.10 If you indicate there is part of your submission that should not be published, we will discuss with you before deciding whether to not publish that part of your submission.

2.11 However, please note that all submissions we receive, including any parts that we do not publish, can be requested under the Official Information Act 1982. This means we would be required to release material that we did not publish unless good reason existed under the Official Information Act to withhold it. We would normally consult with you before releasing any material that you said should not be published.

## When to make a submission

2.12 Please deliver your submissions by **5pm** on **7 November 2017**.

2.13 The Authority will acknowledge receipt of all submissions electronically. Please contact the Submissions' Administrator if you do not receive electronic acknowledgement of your submission within two business days.

# 3 Issues the Authority would like to address

## The existing arrangements

3.1 Wind generators are required to offer their generation in a single band. That band must have a price of $0.01/MWh (or $0.00/MWh if the wind generator has must-run dispatch rights). This means that all offered wind is likely to be scheduled and dispatched.

3.2 Wind generators receive dispatch instructions but are not normally obliged to comply with them. This allows wind generators to generate whatever amount they can from the available wind resource. The main exception is the rare situation where there is a system constraint that affects the wind generator.[1] When this system constraint arises, the dispatch instruction is “flagged for compliance” and the wind generator must comply with the dispatch instruction.

## Issues with the existing arrangements

3.3 The Authority has formed the view that it is possible to improve the efficiency of market scheduling and dispatch for the long-term benefit of consumers by changing the arrangements for wind generator offers.

3.4 A wind generator is likely to have a positive SRMC reflecting incremental wear and tear on assets. While this SRMC will vary between wind generators, and may change depending on wind conditions, the Authority considers these SRMCs are likely to be at least $10/MWh. Efficient scheduling should schedule wind generators:

(a) to their full offered quantity when the spot market price is above the wind generator’s SRMC

(b) to zero when the spot market price is below that SRMC (“centrally coordinated economic withdrawal” of wind generation).

3.5 **Issue 1**: Under existing arrangements, wind generators are almost always scheduled at their full offered quantity, [2] even when market prices are below the wind generator’s SRMC. This means the aggregate market cost of meeting demand is higher than necessary. Wind generators could resolve this by offering less generation at those times (for example, by reducing their offer quantities to zero), but some wind generators have reported they are uncertain whether this would be regarded as acceptable behaviour. The existing Code provisions do not provide a clear mechanism for centrally coordinated economic withdrawal of wind generation.

3.6 **Issue 2**: One wind generator has occasionally withdrawn generation (apparently when they are concerned about low prices) without any signalling of this intention through offers. Significant quantities of generation have occasionally been withdrawn over a short period of time without the system operator being aware this was about to happen. This has caused security concerns. The existing Code provisions do not clearly prohibit this behaviour.

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1 This occurs when the nodal price at the wind generator’s location falls below the wind generator’s offer price (usually $0.01/MWh). This could be due to a transmission constraint binding.

2 Except when there is a system constraint that affects the wind generator (refer to footnote 1).

## Why the Authority is addressing these issues now

3.7 In 2014, a wind generator suddenly reduced output at a wind farm by 80 MW without communicating the reduction to the system operator**.**

3.8 The system operator alleged that the wind generator had breached certain offer provisions in the Code. The Authority investigated the alleged breach. In April 2015, the Authority's Compliance Committee decided to discontinue the investigation, noting that work had started on a Code amendment to clarify the relevant Code provisions.

3.9 The Authority's Board subsequently decided that a wider review of wind offer arrangements was required and tasked the Wholesale Advisory Group (the WAG) with this project. The WAG reported back to the Authority in June 2016, recommending revisions to wind offer arrangements and noting that the costs to the system operator of different options would have to be considered.

3.10 Further to the WAG's recommendations, the Authority engaged the system operator to develop more detailed cost estimates for the WAG's options. The system operator finalised its cost estimates for the different options in January 2017. Based on this information, the Authority developed a proposal for a more sophisticated wind integration system than originally recommended by the WAG. The WAG considered this option but did not recommend it because its implementation costs were considered to be too high at the time when early investigations were carried out in 2016.

3.11 The Authority has continued to work closely with the system operator on developing and refining the proposal in this paper. The proposal would now benefit from wider stakeholder input through a consultation process.

**Q1. Do you agree the issues identified by the Authority warrant changes to the offer arrangements for wind generation?**

# 4 Regulatory statement for the proposed amendment

## Objectives of the proposed amendment

4.1 The proposed amendment is intended to enable wind generators to withdraw their generation in an efficient, centrally coordinated way when the market price is below their SRMC. It would also *prevent* wind generators withdrawing large amounts of generation in ways that are not centrally coordinated.

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

## The proposed amendment

4.2 The proposed amendment would make the following changes.

(a) **New offer form**: It would require wind generators (“intermittent generators” in the Code) to submit offers in a new form (an amended form 2 in Schedule 13.1 of the Code). The new form would have five offer bands rather than one. The offer form would also have a new field labelled "forecast of generation potential". The Authority expects that wind generators would offer their entire nameplate capacity in their offer bands. The separate forecast of generation potential would represent what the wind generator thinks it will be able to generate in the relevant trading period.

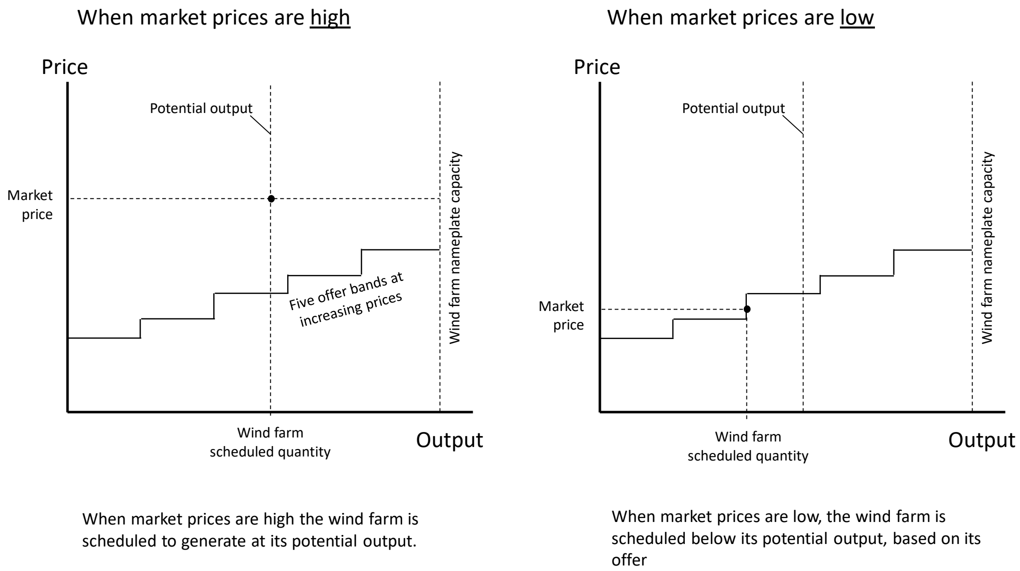
(b) **Short term forecasts (in last two hours)**: In the two hours before a trading period, wind farms must submit a revised forecast of generation potential at least once every half hour. The forecast must be based on a persistence model unless otherwise agreed with the Authority. A persistence model must take into account current output and expected changes in asset availability only. There is an assumption that current wind conditions will persist.

(c) This last assumption is particularly important if a wind farm is withdrawn for economic reasons. The wind farm would determine its forecast of generation potential based on the currently observed wind resource rather using its current output as a baseline for the forecast.

(d) **Gate closure**: Gate closure for grid-connected wind generators will be set to one hour. Gate closure for embedded wind generators will be set to half an hour. Within the gate closure period, wind farms cannot change their offer prices and quantities (although they *are required* in paragraph (b) above to revise their forecast of generation potential at least every half hour).

(e) **New information into schedules**: It would provide for schedules to use wind farm offer bands as an input. Wind generators would be scheduled based on their offer prices and quantities, subject to the constraint that they are not scheduled above their *potential output*. This is illustrated in Figure 1.

**Figure 1: Scheduling a wind farm based on its offer**




(f) **Potential output:** For pre-dispatch schedules,[3] the potential output is the offered "forecast of generation potential". For other schedules, potential output is determined differently as shown in Table 1.

**Table 1: How potential output is determined for different kinds of schedules**

| Schedule type | How *potential output* is determined |
|---|---|
| Pre-dispatch (PRS, NRS)[4] | The latest available offered forecast of generation potential. |
| Real-time dispatch (RTD) | Determine whether the most recent dispatch instruction to the wind generator is flagged for compliance:[5]<br>(i) if it is *not flagged for compliance* (the most usual case), the potential output is the current output measured by the SCADA[6] system<br>(ii) if it *is flagged for compliance*, the potential output is the maximum of:<br>(A) the forecast of generation potential in the final offer<br>(B) the current output.<br>An alternative method for determining the potential output can be used if it is agreed in writing between the wind farm and the Authority. |

3 Such as the price responsive schedule (PRS) and the non-response schedule (NRS).

4 The two formal pre-dispatch schedules are the price responsive schedule (PRS) and the non-response schedule (NRS).

5 Refer to paragraph 4.2(f) for the circumstances in which a dispatch instruction will be "flagged".

6 Supervisory control and data acquisition

| Schedule type | How *potential output* is determined |
|---|---|
| Indicative five minute pricing | Examine the first dispatch instruction to the wind generator issued during the five minute real-time pricing period (or the latest one prior to that if it doesn't exist). Determine whether the dispatch instruction is flagged for compliance:<br>(i) if it is *not flagged for compliance* (the most usual case), the potential output is the five minute average output measured by the SCADA system<br>(ii) if it *is flagged for compliance*, the potential output is the maximum of:<br>(A) the forecast of generation potential in the final offer<br>(B) the five minute average output. |
| Pricing | Determine whether dispatch instructions applying to the wind generator were flagged for compliance for more than half of the trading period:<br>(i) if they were *not flagged for compliance* for more than half the time (the most usual case), the potential output is the adjusted half-hour metering information (in MW)<br>(ii) if they *were flagged for compliance* for more than half the time, the potential output is the maximum of:<br>(A) the forecast of generation potential in the final offer<br>(B) the adjusted half-hour metering information (in MW). |

(g) **Dispatch instruction flags and dispatch compliance**: The system operator would have to flag any dispatch instruction issued to a wind generator for a quantity of active power less than the generator's potential output (from the relevant real-time dispatch schedule). A wind generator must comply with any dispatch instruction that is flagged for compliance. A wind generator need not comply with any dispatch instruction that is not flagged for compliance.

The effect is that, when market prices are above a wind farm's offer prices (likely to be the most common situation), the wind farm receives a dispatch instruction to generate at its potential output, and it may generate whatever output is supported by the wind resource. On the other hand, if market prices are below the wind farm's offer price, or there is a system constraint that affects the wind farm, the wind farm will be dispatched below its potential output, the dispatch instruction will be flagged for compliance, and the wind farm will have to comply with the dispatch instruction.

(h) **Restrictions on unsignalled withdrawal of wind generation**: Wind generators would not be allowed to generate at a rate more than 30 MW below their final forecast of generation potential without an allowable reason. The allowable reasons are outlined in paragraph (h) below.

**Q3. Do you agree that an unsignalled generation withdrawal limit of 30 MW allows sufficient wind farm operational flexibility and does not cause unintended consequences for wind farm owners?**

(i) **Allowable reasons for withdrawal**: Allowable reasons for generating more than 30 MW below the final forecast of generation potential are that the wind generator is:

   (i) responding to a dispatch instruction flagged for compliance or any specific instruction or request from the system operator (including in a grid emergency)

   (ii) prevented by wind conditions from generating at a higher rate

   (iii) unable to increase generation without putting personnel or plant safety at risk. This would include the operation of wind over-speed systems and other automatic asset protection systems

   (iv) controlling output to prevent un-modelled transmission assets from exceeding their ratings (note that un-modelled transmission assets are transmission assets that are not modelled in the system operator's scheduling pricing and dispatch software (SPD))

   (v) responding to an automated signal to maintain frequency

   (vi) responding to reasonably unforeseeable circumstances that require generation to be reduced to comply with the conditions of a resource consent or other law

   (vii) responding to the expected onset of a weather event that would be likely to cause protection systems to shut down the wind farm's assets.

(j) **Restrictions on unsignalled withdrawal applied to a group of wind farms**: The restrictions on unsignalled withdrawal can be applied to a *group* of wind farms as a whole, rather than to an *individual* wind farm. A wind farm owner could apply to the Authority to have two or more stations treated as a group. Grouping could be useful where adjacent wind farms are owned or controlled by the same entity. In this case grouping could allow generation to be switched between different grid injection points. The Authority would expect to discuss the grouping of wind farms with the system operator and the relevant wind farm owner before approving an application.

(k) **Residual demand in pricing schedule**: The proposed use of wind generation offers in the pricing schedule would cause a consequential change in the calculation of residual demand in that schedule. Offered wind generation would be removed from the calculation of residual demand in clause 13.141(1)(b) of the Code. Metered volumes for offered wind generation would no longer have to be given to the grid owner in clause 13.137(1) of the Code.

(l) **Constrained off payments**: Constrained off payments would not be calculated or paid to wind farms. Constrained off amounts should not be paid to wind farms because it will always be a matter of conjecture whether they would have been able to respond to a higher dispatch instruction. No other types of generation receive constrained off payments, unless they are providing frequency keeping.

(m) **Constrained on payments**: Constrained on payments would be calculated and paid to wind farms. The payments will be calculated in a way that is very similar to other generators.

4.3 The drafting of the proposed amendment, with explanatory notes, is contained in Appendix A.

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

### Net benefits

4.4 The base case net benefits of the proposal are expected to be $2.9 million. This is based on expected benefits with a present value of $5.6 million outweighing expected costs with a present value of $2.7 million.

### Benefits

4.5 The benefits of $5.6 million arise from lower cost generation being used to meet demand. An efficient marginal price is set by allowing all generators to offer a price that reflects their true SRMC. In the short term this leads to a productive efficiency gain and in the longer term, promotes investment in more efficient generating plant.

4.6 The Authority's base case analysis assumes that all offered wind generators have a constant SRMC of $10/MWh. Data from 2004 through to the end of January 2017 shows that, with this SRMC assumption, offered wind generators would have incurred private losses of $7.5 million from generating at times when prices were below SRMC. This is the equivalent of $0.40 for every MWh generated from offered wind farms. We project annual output from offered wind farms of 2,270 GWh which suggests ongoing private losses averaging $0.9 million per year.

4.7 The economic benefit from allowing wind generators to withdraw in a well-coordinated way when prices are low is less than the avoided private losses. If wind generation is withdrawn to avoid the losses, additional non-wind generation would be needed to replace it. This generation would be made available from an upward sloping supply curve at costs progressively increasing above the observed market price.

4.8 The analysis assumes that, for every 100 MW of wind withdrawn during low-price periods, the price would rise by $1.68/MWh. This figure was derived from a proxy analysis of the average response of generators to predictable intra-day demand variations. This assumes that non-wind generators would respond to scheduled wind withdrawal by offering additional generation in a way that is comparable with generators' response to known intra-day demand patterns.

4.9 Using this assumed slope for the supply curve, the Authority calculated the economic benefits of the proposal would be 63 % of the avoided private losses (projected to be $0.9 million per annum – see above). The economic benefits are therefore estimated to be $0.58 million per year.

4.10 The base case analysis uses a discount rate of 6 %, a 15 year analysis period, and a conservative assumption that there will be no future growth in wind farm capacity. The resulting present value of benefits is $5.6 million. Sensitivity analysis is covered below from paragraph 4.14.

4.11 There are additional benefits of the proposal that the Authority has not quantified in the above analysis:

(a) With wind generation currently treated as negative load in the final pricing run, SPD cannot back-off wind generation quantities to get a solution. At times, this has led to some unusual pricing outcomes, such as negative spot prices around the

Te Apiti area. By using wind offers, SPD would be able to back-off wind generation in the final pricing solve and improve the efficiency of spot prices.

(b) The proposal would prevent wind generators from withdrawing generation with little or no notice. This would contribute to more efficient pricing and greater system security.

### Costs

4.12 The Authority has estimated implementation costs for the three affected owners of offered wind farms, the system operator, NZX Limited (as wholesale information and trading system provider 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:

**Table 2: Proposal costs**

| Party | Initial costs ($) | Operational annual costs ($) | Information used |
|---|---|---|---|
| Wind generators (total) | 900,000 | 60,000 | Authority estimate |
| System operator | 879,000 | 0 | Based on a report provided by the system operator |
| NZX Limited | 200,000 | 0 | Authority estimate |
| Authority | 50,000 | 5,000 | Authority estimate |
| **Total** | **2,029,000** | **65,000** | |

4.13 These costs have a present value of $2.7 million assuming a 6% discount rate and operational cost flows over a 15 year period.

### Sensitivity analysis

4.14 ***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 generators 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 $2.7 million, so net benefits would increase from $2.9 million to $9.8 million.

4.15 ***To discount rate:*** Even a substantially higher discount rate of 10 % would not eliminate the positive net benefits. The net benefits would fall from $2.9 million to $1.9 million.

4.16 ***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 $2.9 million to $0.8 million.

4.17 ***To growth in offered wind capacity***: An annual growth rate of 3.5% in offered wind capacity would be more consistent with the mixed renewables scenario in the Electricity Demand and Supply Generation Scenarios 2016 produced by the Ministry of Business, Innovation and Employment.[7] Using a growth rate of 3.5% (rather than 0%) would increase the net benefits from $2.9 million to $4.6 million.

4.18 ***To a more conservative assumption about the flexibility of non-wind generators****:* Our base case analysis assumes that non-wind generators 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 generators 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 (-$0.4 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 $2.0 million) or with an assumed 3.5 % per annum growth in wind capacity (net benefits of $0.3 million).

### The Authority has published cost-benefit analysis details

4.19 The Authority has published alongside this paper a spreadsheet setting out the details of the cost-benefit analysis, including all assumptions and sources to the extent that information is not confidential.

| **Q4. Do you agree the benefits of the proposed amendment outweigh its costs?** |
|---|

## The Authority has identified one alternative method for addressing the objectives

4.20 The Authority has identified one alternative method for addressing the objectives. This method is identical to the WAG's preferred option and would:

(a) make no changes to the existing wind generator offer form, and wind generation would continue to be offered at $0.01/MWh (or $0.00/MWh)

(b) require wind generators to record and retain real-time asset availability and control settings

(c) require wind generator offers to be determined based on intended asset availability and control settings

(d) require wind generators to record and retain information about the intended asset availability and control settings used in the offer in place at gate closure

(e) allow wind generators to withdraw assets or limit output if this does not cause generation to fall more than 30 MW below the offered quantity in place at gate closure

(f) prevent wind generators from withdrawing assets or limiting output, without an allowable reason, if this has the effect of reducing generation more than 30 MW below the offered quantity in place at gate closure

(g) not require any changes to system operator systems.

7 Refer to http://www.mbie.govt.nz/info-services/sectors-industries/energy/energy-data-modelling/modelling/electricity-demand-and-generation-scenarios.

4.21 The alternative proposal would satisfy the objectives. It would enable wind generators to withdraw their generation when they expect the market price to be below their SRMC. It would also prevent wind generators withdrawing large amounts of generation without having signalled that intention prior to gate closure.

4.22 However, the alternative proposal would produce lower benefits than the proposal. While wind farms would be able to withdraw generation if they expected prices would be below their SRMC, this would not be achieved in a well-coordinated way. Wind farms would base their withdrawal decisions on their own expectations of upcoming market conditions. They would make this decision at least 1 hour ahead of the trading period. Consequently, their expectations could prove incorrect. This could lead to withdrawal occurring when final prices were high, or to generating when final prices are low (below their SRMC). Consequently, some of the potential benefits would be lost due to this lack of coordination.

4.23 The Authority has estimated that 30 % of the benefits of the proposal would be captured by the alternative proposal. While this 30 % figure is not derived from a fundamental calculation, it is based on analysis of how accurately forecast prices predict when final prices would be below the SRMC of wind.

4.24 The present value of the net benefits of the alternative proposal (relative to the status quo) is estimated at $0.6 million. This consists of benefits of $1.7 million and costs of $1.1 million.[8] This assumes a 6 % discount rate, a 15 year analysis period, no growth in offered wind capacity, a wind SRMC of $10/MWh, and a flexible supply curve for non-wind generation.

4.25 These net benefits are considerably lower than the net benefits the Authority expects to arise from the proposal.

## The proposed amendment is preferred to the other option

4.26 The Authority has evaluated the other means for addressing the objectives and prefers the proposal. The proposal would address the objectives of the proposal more fully. The proposal is expected to produce base case net benefits with a present value of $2.9 million, compared with $0.6 million for the alternative proposal.

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

## The proposed amendment complies with section 32(1) of the Electricity Industry Act 2010

4.27 The Authority's objective under section 15 of the Act is to promote competition in, reliable supply by, and efficient operation of, the electricity industry for the long-term benefit of consumers.

4.28 Section 32(1) of the Act says the Code may contain any provisions that are consistent with the Authority's objective and is necessary or desirable to promote one or all of the following:

8 The apparent error in the difference between benefits and costs is due to rounding.

**Table 3: How the proposal complies with section 32(1) of the Act**

| | |
|---|---|
| (a) competition in the electricity industry; | The proposed amendment will not have any substantial effect on the level of competition in the industry. |
| (b) the reliable supply of electricity to consumers; | The proposed amendment will improve the reliability of supply by reducing the risk of under-frequency events (which can lead to widespread loss of supply) by preventing wind generators rapidly withdrawing their generation without providing any notice to the system operator. |
| (c) the efficient operation of the electricity industry; | The proposed amendment will increase the efficient operation of the industry by enabling the lowest-cost generators to be scheduled and dispatched to meet demand. At present wind generation is scheduled and dispatched to meet demand even if it has a higher short-run marginal cost than other generation plant that is not scheduled or dispatched.<br>In the short term this leads to a productive efficiency gain and in the longer term, promotes investment in more efficient generating plant. |
| (d) the performance by the Authority of its functions; | The proposed amendment will not materially affect the performance of the Authority. |
| (e) any other matter specifically referred to in this Act as a matter for inclusion in the Code. | The proposed amendment will not materially affect any other matter specifically referred to in the Act for inclusion in the Code. |

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

## The Authority has given regard to the Code amendment principles

4.29 When considering amendments to the Code, the Authority is required by its Consultation Charter[9] to have regard to the following Code amendment principles, to the extent that the Authority considers that they are applicable. Table 4 (below) describes the Authority's regard for the Code amendment principles in the preparation of the proposal.

9 The consultation charter is one of the Authority's foundation document and is available at:http://www.ea.govt.nz/about-us/documents-publications/foundation-documents/

**Table 4: Regard for Code amendment principles**

| Principle | Comment |
|---|---|
| 1. Lawful | The proposal is lawful, and is consistent with the statutory objective (see paragraph 4.27) and with the empowering provisions of the Act. |
| 2. Provides clearly identified efficiency gains or addresses market or regulatory failure | The efficiency gains are set out in the evaluation of the costs and benefits (see paragraph 4.4 to 4.19). |
| 3. Net benefits are quantified | The extent to which the Authority has been able to estimate the efficiency gains is set out in the evaluation of the costs and benefits (see paragraph 4.4 to 4.19). |

4.30 Principles 4 to 9 are not included in Table 4. They apply only if it is unclear which option is the best (refer clause 2.5 of the Consultation Charter). At this point, the Authority considers it is clear the proposed option is the best.

# Appendix A Proposed amendment with explanatory notes

## Part 1
## Preliminary provisions

*This note is not part of the proposed Code*

**Note:**

Explanatory notes are inserted below in this format. They are not part of the proposed Code amendments.

**bona fide physical reason** includes,—

(a) in relation to a **generator**, or a **purchaser**, or an **ancillary service agent** or a **grid owner**, a situation where personnel or plant safety is at risk; and

(b) in relation to a **generator** or an **ancillary service agent** providing **partly loaded spinning reserve**, **tail water depressed reserve** or **frequency keeping**,—

(i) a reasonably unforeseeable change in generating capability, reserve capability, or **frequency keeping** capability (as the case may be) from an item of **generating plant** that is the subject of an existing **offer**, **reserve offer**, or offer to provide **frequency keeping** by that **generator** or **ancillary service agent**; or

(ii) a reasonably unforeseeable change in the level of expected uncontrollable water inflows into the head pond of a hydro station that is the subject of an existing **offer**, **reserve offer**, or offer to provide **frequency keeping** by that **generator** or **ancillary service agent**; or

(iii) a reasonably unforeseeable change in circumstances such that the **generator** or **ancillary service agent** will breach any consent held by it under the Resource Management Act 1991; or

(iv) a reasonably unforeseeable physical infeasibility that arises from a **price-responsive schedule**, a **non-response schedule**, or a **dispatch schedule**; and

(ba) in relation to an **intermittent generator**, a situation in which—

(i) wind conditions prevent the **intermittent generator** from generating at the level expected; or

(ii) the **intermittent generator** reduces the output of an **intermittent generating station**—

(A) to prevent an un-modelled transmission asset from exceeding its ratings; or

(B) in order to comply with an automated signal to maintain frequency; or

(C) in light of reasonably unforeseeable circumstances that require the output of the **intermittent generating station** to be reduced to enable the **intermittent generator** to comply with the conditions of a resource consent or other law; or

(D) in anticipation of the expected onset of a weather event that would be likely to cause the **intermittent generating station's** asset protection systems to shut down assets forming part of the **intermittent generating station**; and

*This note is not part of the proposed Code*

**Note: Use of the term BFPR**

The term "bona fide physical reason" (BFPR) is presently used only in clauses:

- 13.19: a generator may submit a revised offer during a gate closure period if it is necessary due to a BFPR
- 13.19A, 13.34 and 13.47: these clauses contain similar provisions for nominated dispatch bids, grid owner information (which is used as an input into schedules) and reserve offers
- 13.97: in a grid emergency a non-wind generator may not reduce its offered quantity (and an ancillary service agent may not reduce its reserve offer quantity) unless it has a BFPR.

These references to BFPR either do not apply to, or are not relevant for, wind generators. The proposal in this paper would use the term BFPR in the proposed new clause 13.87A. Under that proposed clause, an intermittent generator must not reduce generation more than 30 MW below the forecast of generation potential specified in its final offer unless it does so to comply with a dispatch instruction, or has a BFPR. This would make the definition of BFPR relevant for wind generators.

*This note is not part of the proposed Code*

**Note: Definition of BFPR in the context of clause 13.87A**

***Un-modelled transmission assets:*** Paragraph (ba)(ii)(A) of the definition of BFPR is intended to cover situations where a wind generator needs to manage its output to prevent physical overloading of a local transmission line that is not modelled within SPD.

***Expected onset of a weather event that would cause shut down:*** Paragraph (ba)(ii)(D) of the definition of BFPR is intended to cover situations where a wind generator shuts down turbines shortly before a storm front arrives. Some wind generators may find this provision useful if it helps the wind farm to return turbines to service more quickly after the storm passes. For some wind generators it may take longer to restart turbines if automatic asset protection systems have shut the turbines down.

(c) in relation to a **purchaser**, or an **ancillary service agent** providing **interruptible load**,—
  (i) a reasonably unforeseeable full or partial loss of demand or reserve capability (as the case may be) at a **grid exit point** that is the subject of an existing **bid** or **reserve offer** by the **purchaser** or the **ancillary service agent**; or
  (ii) a reasonably unforeseeable change in circumstances such that the **purchaser** or **ancillary service agent** will breach any consent held by it under the Resource Management Act 1991; or
  (iii) a reasonably unforeseeable full or partial loss of generating capability from an item of **generating plant** owned by, or the subject of a supply contract with, that **purchaser** during the relevant **trading periods**; and

(d) in relation to a **grid owner**, a reasonably unforeseeable loss of full or partial capacity on transmission plant forming part of the **grid**

<u>**flagged**, in relation to a **dispatch instruction** issued to an **intermittent generator**, means an indication on the **dispatch instruction** that it is a **dispatch instruction** of the kind described in clause 13.73(1A), and **flag** has a corresponding meaning</u>

**forecast of generation potential** means, in relation to an **intermittent generating station**, an **intermittent generator's** estimate of the **electricity** (specified in **MW**) it will generate during a **trading period**, if—

(a) the **system operator** issues **dispatch instructions** to the **intermittent generator** for the **intermittent generating station** for the **trading period**; and

(b) none of the **dispatch instructions** are **flagged** in accordance with clause 13.73(1A)

**gate closure period**, in relation to a **trading period** for which a **generator** or **ancillary service agent** has submitted an **offer** or **reserve offer**, or for which a **dispatchable load purchaser** has submitted a **nominated dispatch bid**, means—

(a) the **trading period** immediately preceding the **trading period** to which the **offer** or **reserve offer** relates, for—
    (i) an **embedded generator**:
    ~~(ii) an **intermittent generator**:~~
    (iii) an **ancillary service agent** that is also an **embedded generator**; and

(b) the 2 **trading periods** immediately preceding the **trading period** to which the **offer**, **reserve offer**, or **nominated dispatch bid** relates, for—
    (i) any other **generator**:
    (ii) any other **ancillary service agent**:
    (iii) a **dispatchable load purchaser**

*This note is not part of the proposed Code*

**Note: Gate closure for wind generation**

Under the present Code, gate closure is largely irrelevant for wind generators. The main application of gate closure is to prevent a generator from changing its offer prices or quantities within the gate closure period. This has no substantial effect on wind generators because:

(a) their offer prices must be either $0.00 or $0.01/MWh, so there is little to be gained from changing an offer price anyway

(b) they have an *overriding obligation* to revise their offer quantities at least once every half hour within the gate closure period.

Technically, the gate closure for wind generators currently begins half an hour before the start of the trading period. However, as noted, this has little practical effect.

Under the proposal, the gate closure period for grid-connected wind generators would begin one hour before the trading period, as for other grid-connected generators. It would also have some practical effect.

Under the proposal, wind will offer in up to five price-quantity bands. The prohibition on changing offer prices and quantities during the gate closure period would have practical effect for wind generators because:

(a) they have flexibility over their offer prices. A wind generator would be prevented from changing offer prices during the gate closure period, and

(b) they have no overriding obligation to revise their offer quantity. The short-term persistence-based forecasting obligation would instead relate to the new “forecast of generation potential” field. A wind generator would be prevented from changing their offer quantity during the gate closure period.

**intermittent generating station group** means 2 or more **intermittent generating stations** owned by the same **intermittent generator** that the **Authority** has approved under clause 13.87B

**offer stack** means the stack generated from ranking in price order, from lowest to highest, all **offers** to sell **electricity** as given to the **pricing manager** under clause 13.141(1)(c), adjusted so that for each **intermittent generating station**, the total offered quantity is not greater than the potential output for the **intermittent generating station**, determined in accordance with clause 13.141(1)(caa)

## Part 13
## Trading arrangements

…

### 13.9 Information that offers must contain

Each **offer** submitted by a **generator** must—

(a) other than for **intermittent generators**, **type A co-generators**, and **type B co-generators**, contain all information required by Form 1 in Schedule 13.1; and

(b) *[Revoked]*

(c) if the **offer** is submitted by an **intermittent generator** for an **intermittent generating station**,—

  (i) contain the information required by Form 2 in Schedule 13.1; and

  ~~(ii) have a maximum of 1 price band for each **trading period**; and~~

  ~~(iii) specify a price of either $0.00 (subject to clause 13.116) or $0.01 for the price band; and~~

(d) if the **offer** is submitted by a **type A co-generator** for a **type A industrial co-generating station** or by a **type B co-generator** for a **type B industrial co-generating station**,—

  (i) contain the information required by Form 3 in Schedule 13.1; and

  (ii) have a maximum of 2 price bands for each **trading period**; and

  (iii) specify a price of either $0.00 (in accordance with clause 13.116) or $0.01 for the price band.

### 13.9A Offer not to exceed capability

(1) The total **MW** specified in each **offer** submitted by a **generator** must, in relation to the **generating plant** that is the subject of the **offer**, not exceed the total **MW** that the **generator** expects to be capable of generating at the relevant **point of connection** to the **grid** for the relevant **trading period**.

(2) Subclause (1) does not apply to an **intermittent generator**.

*This note is not part of the proposed Code*

**Note: Excluding intermittent generators from the effect of clause 13.9A**

The Authority expects that, under this proposal, wind farms would offer their entire nameplate capacity in the price-quantity pairs. The new “forecast of generation potential” would be the forecast of what the wind farm believes it can generate given its expectations about wind conditions. Clause 13.9A(1) relates to the price-quantity pairs.

**13.9B Offer requirements for intermittent generators**

Each **offer** submitted by an **intermittent generator** must, in relation to the **generating plant** that is the subject of the **offer**,—

(a) not exceed the **nameplate capacity** of the **generating plant**; and

(b) include a **forecast of generation potential** for the **trading period** to which the **offer** relates.

…

**13.12 Offers may contain up to 5 price bands**

Subject to clause 13.9~~(c) and~~ (d), an **offer** submitted by a **generator** may have a maximum of 5 price bands for each **trading period**, with the 1st price band containing the lowest price offered, and each subsequent band having a higher price than the band preceding it. ~~The price offered in each band must increase progressively from band to band as the aggregate quantity increases.~~

> *This note is not part of the proposed Code*
>
> **Note: Change to clause 13.12**
>
> The proposed change to clause 13.12 is intended to make the clause easier to read. It is not expected to lead to any changes in practice.

…

**13.15 How price is to be specified in bids or offers**

Prices in **bids** or **offers** must be expressed in dollars and whole cents per **MWh** excluding any **GST**. There is no upper limit on the prices that may be specified and the lower limit is $0.00/**MWh**, subject to clauses 13.9~~(c) and~~ (d), 13.24, 13.26, and 13.116.

…

**13.17 Offers may be revised**

(1) Subject to subclauses (2) to (4), a **generator** may revise an **offer** at any time before the beginning of the **trading period** to which the **offer** relates by submitting a new **offer** to the **system operator**.

(2) A **generator** must not revise any of its **offer** prices during a **gate closure period**.

(3) A **generator** must not revise the **MW** specified in any price band in an **offer** during a **gate closure period**, unless clause 13.18(1), 13.18(1A), ~~13.18A,~~ or 13.19 applies.

(4) A **generator** must not revise any of the following **offer** parameters during a **gate closure period**, unless clause 13.19 applies:

(a) ramp rates:

(b) maximum output (including overload).

**13.18 When revised offer to be submitted**

(1) A **generator**, other than an **intermittent generator**, must immediately submit a revised **offer** to the **system operator** if, at any time before the **trading period** to which the **offer** relates, the total **MW** specified in an **offer** exceeds, by more than 5 **MW**, the total **MW** that the **generator** expects to be capable of generating at the relevant **point of connection** to the **grid** for the relevant **trading period**.

(1A) A **generator**, other than an **intermittent generator** may submit a revised **offer** to the **system operator** if the total **MW** specified in an **offer** exceeds, by 5 **MW** or less, the total **MW** that the **generator** expects to be capable of generating at the relevant **point of connection** to the **grid** for the relevant **trading period**.

(1B) The submission of a revised **offer** under subclause (1) or subclause (1A) does not relieve the **generator** of liability for breach of any other provision of this Code.

(2) *[Revoked]*

(3) Subclause (1) does not apply—

~~(a) in every case,~~ after the beginning of the **trading period** to which an **offer** relates~~; and~~

~~(b) in relation to an **intermittent generator**, during the 2 hours immediately preceding the **trading period** to which an **offer** relates~~.

*This note is not part of the proposed Code*

**Note: Reasons for, and consequences of, excluding wind ("intermittent") generators from clause 13.18(1)**

The proposal introduces the "forecast of generation potential" as a new field for wind offers. That field would take over the role formerly played by the offered quantity for wind generators. Under the proposal, a wind farm's offered quantity (the total of all quantities in the price-quantity pairs) is likely to equal the nameplate capacity of the wind farm. Clause 13.18(1) relates to the quantities in the price-quantity pairs. It would not be appropriate to allow clause 13.18(1) to continue to apply to wind generator quantities in the price-quantity pairs. Consequently it is proposed to exclude wind generators from the effect of clause 13.18A(1).

The Authority considered adapting the provision so that it referred, in the case of a wind generator, to the forecast of generation potential. The Authority considered this also would not be appropriate. The clause uses the phrase "the total MW that the generator expects to be capable of generating". This focus on expectations about capability seems appropriate for controllable forms of generation. However, for intermittent generation driven by a volatile and uncertain resource, requirements for high-quality energy forecasting would also have to address the process for forecasting the underlying resource.

The Authority then considered designing an entirely new provision governing wind farm forecasting. The Authority decided that would not be appropriate. It is beyond the scope of this project to impose substantial new obligations on the quality of wind forecasts or the effort that must go into them.

Consequently the Authority proposes to exclude wind generators from the effect of clause 13.18A(1) and not to insert an equivalent, remodelled clause specifically for wind. The Authority will continue to monitor the quality of wind generation forecasts. If the Authority becomes concerned about the quality of those forecasts, Code provisions can be added as part of a separate project to create the necessary obligations.

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

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

(2) A revised ~~**offer**~~ <u>**forecast of generation potential**</u> 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~~<u>:</u>

<u>(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:</u>

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

**13.19 When revised offers may be submitted during gate closure period**

(1) A **generator**<u>, other than an **intermittent generator**,</u> may submit a revised **offer** to the **system operator** during a **gate closure period** if—

(a) the revision is necessary due to a **bona fide physical reason**; or

(b) the **system operator** issues a **formal notice** under clause 5 of **Technical Code** B of Schedule 8.3; or

(c) a **bona fide physical reason** that made a revision necessary under paragraph (a) ceases to exist sooner than was expected at the time it arose, and—

(i) the 1st **trading period** after the original **bona fide physical reason** ceases to exist is within 24 hours after the circumstances that constituted the original **bona fide physical reason** arose; and

(ii) the total change in **MW** specified in the **offer** that is revised as a result of the **bona fide physical reason** ceasing to exist is the same or less than the total change in **MW** specified in the **offer** that was made as a result of the original **bona fide physical reason**.

(2) A **generator** that submits a revised **offer** under subclause (1)(c) must do so as soon as possible after the relevant **bona fide physical reason** ceases to exist.

**13.19AA Limitations on revised offers**

A **generator** that submits a revised **offer** under clauses 13.18(1), 13.18(1A), or 13.19(1) during a **gate closure period** must ensure that—

(a) the revised **offer** only differs from the original **offer** to the extent necessary to ensure that the **MW** specified in the revised **offer** is the **MW** that the **generator** expects to be capable of generating at the relevant **point of connection** to the **grid** for the relevant **trading period**; and

(b) the revised **offer** complies with the following:

(i) the reduction in **MW** specified in the revised **offer** must be first deducted from the **MW** offered in the highest price band:

(ii) if the reduction in **MW** exceeds the **MW** in the highest price band, the remainder must be deducted from the price bands below the highest, in descending order as the **MW** in each price band is reduced to zero, until all of the reduction is reflected in the revised **offer**.

…

**13.20 System operator notified of revised nominated bids or offers in certain circumstances**

(1) This clause applies to each **purchaser** or **generator** that submits a revised **nominated bid** or **offer** during the 15 minutes immediately preceding the **trading period** to which the revised **nominated bid** or **offer** relates.

(2) A **purchaser** or **generator** that submits a revised **nominated bid** or **offer** in the time frame described in subclause (1) must immediately notify the **system operator** of the revision by telephone or electronic means (if the **system operator** and the **purchaser** or **generator** have agreed the electronic means before the **purchaser** or **generator** notifies the **system operator** of the revision).

(3) Subclause (2) does not apply to an **intermittent generator** submitting a revised ~~**offer**~~ <u>**forecast of generation potential**</u> under clause 13.18A.

**13.21 Authority notified of revised nominated dispatch bid or offer during gate closure period**

(1) A **dispatchable load purchaser** or **generator** that submits a revised **nominated dispatch bid** or a revised **offer** to the **system operator** during a **gate closure period** must report each revision to the **Authority** in writing together with an explanation of the reasons for the revision.

(1A) The **dispatchable load purchaser** or **generator** must report the revision to the **Authority** no later than 1700 hours on the 1st **business day** following the **trading day** on which the revision was made.

(1B) Subclauses (1) and (1A) do not apply to an **intermittent generator** submitting a revised ~~**offer**~~ <u>**forecast of generation potential**</u> under clause 13.18A.

(2) *[Revoked]*

…

**13.58A Inputs for price-responsive schedule and non-response schedule**

(1) The **system operator** must prepare a **price-responsive schedule** using the following inputs:

(a) **offers** and **reserve offers**; and

<u>(aa) the potential output of all **intermittent generating stations**, determined using the most recent **forecast of generation potential** for each **intermittent generating station** submitted under clause 13.18A; and</u>

(b) **nominated bids**; and

(c) the forecast prepared by the **system operator** under clause 13.7A(1); and

(d) **difference bids**; and

(e) information provided to the **system operator** by a **grid owner** under clauses 13.29 to 13.34 about—

(i) the AC transmission system configuration, capacity, and **losses**; and

(ii) the capability of the **HVDC link** including its **configuration**, capacity, **losses**, the direction of any transfer limit, and any minimum or maximum transfer limits; and

(iii) transformer configuration, capacity, and **losses**; and

(f) the adjustments specified in subclause (2)(e), subject to any exceptions specified in the **policy statement**; and

(g) information about **voltage support** from contracts held by the **system operator** under the **procurement plan**; and

(h) information from **ancillary service agents** about **instantaneous reserves** procured under the **procurement plan**.

(2) The **system operator** must prepare a **non-response schedule** using the following inputs:

(a) **offers**, **nominated dispatch bids**, and **reserve offers**; and

<u>(aa) the potential output of all **intermittent generating stations**, determined using the most recent **forecast of generation potential** for each **intermittent generating station** submitted under clause 13.18A; and</u>

(b) **nominated non-dispatch bid** quantities; and

(c) the forecast prepared by the **system operator** under clause 13.7A(1); and

(d) information provided to the **system operator** by a **grid owner** under clauses 13.29 to 13.34 referring to—

(i) the AC transmission system configuration, capacity, and **losses**; and

(ii) the capability of the **HVDC link** including its **configuration**, capacity, **losses**, the direction of any transfer limit, and any minimum or maximum transfer limits; and

(iii) transformer configuration, capacity, and **losses**; and

(e) adjustments made by the **system operator** under clause 13(1) of Schedule 13.3, in order to meet the **dispatch objective**; and

(f) information about **voltage support** from contracts held by the **system operator** under the **procurement plan**; and

(g) information from **ancillary service agents** about **instantaneous reserves** procured under the **procurement plan**.

…

**13.71 System operator to use certain things**

(1) In determining **dispatch instructions** when implementing a **dispatch schedule** under clause 13.72(1)(a), the **system operator** must use—

(a) the price order in the current **dispatch schedule**; and

(b) any revised **offer** from a **generator** notified in accordance with clause 13.19 ~~(except for revised **offers** submitted by an **intermittent generator** under clause 13.19(1)(a)(iii))~~; and

(c) any ramp rates of **generators**~~. For **intermittent generators**, the ramp rates are those agreed between the **intermittent generator** and the **system operator**~~; and

*This note is not part of the proposed Code*

**Note: Change to clause 13.71(1)(c) regarding agreed ramp rates for wind generators**

At present the dispatch schedule uses a zero upward ramp rate (with an arbitrarily high offered quantity) for wind generators to ensure they are never dispatched above their initial MW. Under the proposed regime with multi-tiered wind offers there would be no reason for this to continue. The offered ramp rates would be used for wind generators.

(d) any revised **nominated bid** quantities from a **purchaser** notified in accordance with clause 13.19A; and

~~(e) any additional information regarding the future output of an **intermittent generator** submitted by an **intermittent generator** in agreement with the **system operator**; and~~

(ea) the potential output of all **intermittent generating stations**, determined in accordance with subclause (3); and

(f) the actual profile of **demand** during the previous **trading period**; and

(g) the expected profile of **demand** within the current **trading period** and the subsequent **trading periods**; and

(h) the current output levels of each **generator**; and

(i) any revised **reserve offer** from an **ancillary service agent** notified in accordance with clause 13.48; and

(j) any revised information received from a **grid owner** under clause 13.34(1); and

(k) the order in which reserves may be called as specified by the **system operator** from time to time.

(2) In determining **dispatch instructions** under clause 13.72(1)(b), the **system operator** must use revised **nominated dispatch bids** submitted under clause 13.19A.

(3) The **system operator** must, in determining the potential output of an **intermittent generating station** for the purposes of subclause (1)(ea), use the following information:

(a) if the most recent **dispatch instruction** to the relevant **intermittent generator** for the **intermittent generating station** was not **flagged**, the actual output in **MW** of the **intermittent generating station**:

(b) if the most recent **dispatch instruction** to the relevant **intermittent generator** for the **intermittent generating station** was **flagged**, the greater of—

(i) the **forecast of generation potential** specified in the **intermittent generator's** final **offer** for the relevant **intermittent generating station** submitted under clause 13.18A; and

(ii) the actual output in **MW** of the **intermittent generating station**:

(c) if the **intermittent generator** and the **Authority** have agreed in writing that an alternative estimate may be provided, the alternative estimate of the potential output of the **intermittent generating station** provided by the relevant **intermittent generator**.

*This note is not part of the proposed Code*

**Note: Agreed alternative estimate in clause 13.71(3)(c)**

The proposed provision for an agreed alternative estimate in clause 13.71(3)(c) is intended to enable a wind farm to use real time information to estimate its potential level. The wind farm may be controlling its generation below its potential level, so its current output may not indicate its potential. However, the wind farm may be able to use observed real time wind conditions to estimate its potential generation. In this case it could provide that real time information to the system operator. If the system operator agrees, that information could be used to determine the potential output for the purpose of dispatch.

**13.72 System operator to issue dispatch instructions**

(1) The **system operator** must implement—

(a) a **dispatch schedule**, and any departure from the **dispatch schedule** under clause 13.70, by issuing **dispatch instructions** to,—

(i) **generators**; and

(ii) **ancillary service agents**:

(b) a **non-response schedule** by issuing **dispatch instructions** to **dispatchable load purchasers** that have submitted **nominated dispatch bids**.

(2) The **system operator** must issue each **dispatch instruction** in a reasonable and timely manner to enable the **participant** to which the **dispatch instruction** is issued to comply with the **dispatch instruction**.

(3) Despite subclause (1), the **system operator** is not required to issue a **dispatch instruction** to a **participant** if—

(a) the **dispatch instruction** is—

(i) to provide a quantity of **active power** under clause 13.73(1)(a); or

(ii) to provide a quantity of **instantaneous reserve** under clause 13.73(1)(b); and

(b) the **dispatch instruction** would differ from the most recent **dispatch instruction** issued to the **participant** by 1 **MW** or less.

**13.73 Content of dispatch instructions to generators, ancillary service agents, and dispatchable load purchasers**

(1) The **system operator** must ensure that each **dispatch instruction** it issues under clause 13.72(1)(a) instructs the **generator** or **ancillary service agent** to carry out 1 of the following in relation to a **generating plant**, a **generating unit**, a **block dispatch group**, a **station dispatch group**, a **frequency keeping unit**, or **interruptible load**:

(a) provide a quantity of **active power**:

(b) provide a quantity of **instantaneous reserve**:

(c) provide a quantity and quality of reserve power or alternative to regulate frequency continuously:

(d) provide a quantity of **reactive power**:

(e) adjust transformer tap positions to maintain voltage levels:

(f) provide a level of voltage:

(g) **synchronise** or **de-synchronise generating plant** within the current **trading period** or the next **trading period** either directly or in accordance with any process that may be agreed with the **generator**:

(h) switch on or switch off schemes for over frequency tripping where such capability exists in **generating plant** that a **generator** has offered to provide to the **system operator**:

(i) manage the **generating plant** within a **block dispatch group** or **station dispatch group** so as to ensure the largest single reserve risk within that **block dispatch group** or **station dispatch group** does not exceed the relevant maximum reserve risk notified by the **system operator** for the North Island or the South Island for each **trading period**:

(j) manage the total aggregate generation for each **sub-block dispatch group** or **sub-station dispatch group** for that **generator** so as not to exceed the total sum of the **dispatched** quantities for each **generating plant** or **generating unit** comprising that **sub-block dispatch group** or **sub-station dispatch group** for the duration of the notice received under clauses 13.60, 13.61, or 13.64 to 13.66:

(k) manage the total aggregate generation for each **block dispatch group** or **station dispatch group** for that **generator** so as to meet the total sum of the **dispatched** quantities for each **generating station** or **generating unit** comprising that **block dispatch group** or **station dispatch group**.

(1A) The **system operator** must include an indication (**flag**) in each **dispatch instruction** it issues to an **intermittent generator** under clause 13.72(1)(a) if the **intermittent generator** is **dispatched** for a **trading period** at a quantity less than the potential output of the relevant **intermittent generating station**.

(1AA) For the purposes of subclause (1A), the potential output of an **intermittent generating station** is the potential output for the relevant **intermittent generating station** determined by the **system operator** under clause 13.71(3).

(2) The **system operator** must ensure that each **dispatch instruction** issued under clause 13.72(1)(b) instructs the **dispatchable load purchaser** to use a specified quantity of **electricity** in relation to a **dispatch-capable load station**.

*This note is not part of the proposed Code*

**Note: Flagged dispatch instructions to wind farms**

Clause 13.73(1A) requires the system operator to flag a dispatch instruction if the wind farm is dispatched below its potential. The Authority notes that the system operator already flags dispatch instructions where the wind farm is dispatched below its current generation.

…

**13.82 Dispatch instructions to be complied with**

(1) This clause applies to—
  (a) a **generator**; and
  (b) an **ancillary service agent**; and
  (c) a **dispatched purchaser**.

(2) Each **participant** to which this clause applies must comply with a **dispatch instruction** properly issued by the **system operator** under clause 13.72 unless,—
  (a) in the **participant's** reasonable opinion,—
    (i) personnel or plant safety is at risk; or
    (ii) following the **dispatch instruction** will contravene a law; or
  (b) the **generating plant** or **dispatch-capable load station** is already responding to an automated signal to activate—
    (i) **capacity reserve**; or
    (ii) **instantaneous reserve**; or
    (iii) **automatic under-frequency load shedding**; or
    (iv) **over frequency reserve**; or
  (c) the **participant** is a **generator** or **ancillary service agent** acting in accordance with clause 13.86; or
  (d) the **participant** is an **intermittent generator** ~~that has complied with clause 13.17 and clause 13.18A,~~ and the **system operator** has not **flagged** the **dispatch instruction** in accordance with clause 13.73(1A) ~~advised that there is—~~
    ~~(i) a **grid emergency**; or~~
    ~~(ii) a system **constraint** that directly affects the **intermittent generator**~~; or

…

…

**13.87A Intermittent generators must not substantially reduce generation**

(1) An **intermittent generator** must not generate **electricity** during a **trading period** at a rate that is more than 30 **MW** below the **forecast of generation potential** specified in the **intermittent generator's** final **offer** for the **trading period** submitted under clause 13.18A, unless—

(a) the **intermittent generator** reduces the output of the relevant **intermittent generating station** in order to comply with a **flagged dispatch instruction** under clause 13.73(1A), or any other instruction issued by the **system operator**; or

(b) the **intermittent generator** has a **bona fide physical reason**.

(2) If an **intermittent generator** generates **electricity** during a **trading period** at a rate that is below the rate specified in subclause (1) for 1 or more **trading periods** in a calendar month, the **intermittent generator** must provide a report to the **Authority** no later than 5 **business days** after the beginning of the next calendar month.

(3) A report provided to the **Authority** under subclause (2) must specify—

(a) the **trading periods** in relation to which the **intermittent generator** generated **electricity** at a rate that was below the rate specified in subclause (1); and

(b) in relation to each such **trading period**, an explanation of the reason for the **intermittent generator** generating **electricity** at a rate that was below the rate specified in subclause (1); and

(c) if the **intermittent generator** considers that one of the reasons in subclause (1) applies in respect of any of the **trading periods** specified in the report, the **intermittent generator's** reasons for that view.

*This note is not part of the proposed Code*

**Note: 30 MW limit in subclause 13.87A(1)**

The proposal would allow wind farms to offer generation in multiple bands at different prices. This allows the withdrawal of wind generation in a centrally coordinated way. However, the Code would still need to prevent a wind farm withdrawing a large amount of generation in a way that was not centrally coordinated. This is the purpose of subclause 13.87A(1). A wind farm cannot deliberately reduce its generation in real time by more than 30 MW without first having signalled that through offers. That enables the reduction to be centrally coordinated through the system operator.

The 30 MW limit is designed to prevent large uncoordinated reductions without imposing too strong an obligation on wind farms. Generation reductions smaller than 30 MW, such as opportunistic maintenance on a string of turbines, would not breach clause 13.87A(1). However, wind farms still have an obligation under subclause 13.18A, and particularly under subclause 13.18A(3)(b), to signal any known or expected changes in availability and capability in their persistence-based offers.

**13.87B Intermittent generating station groups**

(1) An **intermittent generator** may apply to the **Authority** to have 2 or more **intermittent generating stations** treated as an **intermittent generating station group**, by submitting an application in such manner and form as the **Authority** may specify from time to time.

(2) The **Authority** must,—

(a) as soon as practicable after receiving an application, notify the **system operator**; and

(b) no later than 20 **business days** after receiving an application, either approve or decline the application, taking into account any views provided by the **system operator**.

(3) The **Authority** must **publicise** and maintain a list of all approved **intermittent generating station groups**.

(4) Clause 13.87A(1) applies in relation to an **intermittent generating station group**—

(a) as if it is a single **intermittent generating station**; and

(b) as if the **forecast of generation potential** referred to in that clause is equal to the sum of the **forecasts of generation potential** specified in the **intermittent generator's** final **offers** submitted under clause 13.18A for all **intermittent generating stations** in the group.

*This note is not part of the proposed Code*

**Note: Grouping intermittent generating stations**

Some wind farms have the ability to switch generation between more than one grid injection point (GIP). Clause 13.87A applies at the station level (the level at which offers are made), which means at the individual GIP level. This means that, if a wind farm switched 35 MW between two GIPs without signalling this through offers, it would breach clause 13.87A, despite its total generation from the wind farm being unaffected. The purpose of clause 13.87B is to allow a wind farm to choose that clause 13.87A will apply across multiple GIPs as a whole, and not at the individual GIP level. This would allow the switching of generation between those GIPs. It would also mean that the 30 MW limit applies to the group as a whole, rather than having the 30 MW limits at individual GIPs aggregating to perhaps a 60 MW or 90 MW limit for the whole wind farm.

It is envisaged that the Authority would approve an application only if the GIPs are electrically close, so that transmission issues are likely to be less important to overall system management than greater confidence about the overall output of the wind farm.

…

**13.97 Grid emergency situations**

(1) The **system operator** may, at any time, declare a **grid emergency** in accordance with **Technical Code** B of Schedule 8.3.

(2) Despite clauses 13.6 to 13.27 and clauses 13.37 to 13.54, if the **system operator** has declared a **grid emergency**,**—**

(a) a **generator**~~, other than an **intermittent generator**,~~ may not reduce the **MW** specified in any of the **offers** made by the **generator** for the **trading periods** and **grid injection points** affected by the **grid emergency**, unless the **generator** has a **bona fide physical reason** that makes the reduction necessary; and

(b) an **ancillary service agent** may not reduce the **instantaneous reserve** specified in any of the **reserve offers** made by the **ancillary service agent** for the **trading periods** and **points of connection** with the **grid** affected by the **grid emergency**, unless the **ancillary service agent** has a **bona fide physical reason** that makes the reduction necessary; and

(c) the **system operator** must accept any reduction made under paragraphs (a) or (b).

(3) Subclause (2)(a) does not apply in relation to the **MW** specified in the **forecast of generation potential** specified in any of the **offers** made by an **intermittent generator**.

*This note is not part of the proposed Code*

**Note: Amendment to clause 13.97(2)(a)**

At present, wind generators are excluded from the effect of subclause 13.97(2)(a). This reflects the fact that their offered quantities are revised frequently during the last 2 hours based on a persistence model. Reductions in their offered quantities are likely to reflect circumstances beyond their control (i.e. wind conditions).

The proposal introduces a new offer field called the forecast of generation potential. This forecast would be the thing that changes frequently in a way that is beyond the direct control of the wind farms. Clause 13.97(2)(a) relates to the MW quantities in the price-quantity pairs in offers, not to the forecast of generation potential. The price-quantity pairs would be within the control of the wind farm. So there is no longer a reason to exclude wind generators from the effect of clause 13.97(2)(a).

Despite the proposed revision to clause 13.97(2)(a), overall outcomes would remain unchanged. When there is a grid emergency, most generators will be prevented from reducing offered quantities, but wind farms will not be prevented from reducing their forecast generation (now in the "forecast of generation potential" field).

…

**13.136 Generators to provide half-hour metering information**

(1) Each **generator** must give the relevant **grid owner half-hour metering information** under clause 13.138 in relation to **generating plant** ~~that is subject to a **dispatch instruction**~~—

(a) that injects **electricity** directly into a **local network** or an **embedded network**; or

(b) if the **meter** configuration is such that the **electricity** flows into a **local network** without first passing through a **grid injection point** or **grid exit point metering installation**.

(1A) For the purposes of subclause (1), the relevant **grid owner** is—

(a) in relation to a **generator** (other than an **embedded generator**), the **grid owner** of the **grid** to which the **generator's generation** is **connected**; and

(b) in relation to a **generator** that is an **embedded generator**, the **grid owner** of the **grid** to which the **local network** to which the **embedded generator** is directly or indirectly **connected**, is **connected**.

(2) ~~To avoid doubt,~~ S~~s~~ubclause (1) does not apply in respect of—

(a) any **unoffered generation**; or

(b) **electricity** supplied from—

~~(i) an **intermittent generating station**; or~~

(ii) a **type B industrial co-generating station**.

*This note is not part of the proposed Code*

**Note: Amendment to clause 13.136**

The proposed amendment to clause 13.136 is discussed in the note below following the proposed changed to clause 13.141.

**13.137 Generators to provide half-hour metering information for unoffered and intermittent generation and type B industrial co-generation**

(1) Each **generator** must give the relevant **grid owner half-hour metering information** for—

(a) **unoffered generation** from a **generating station** with a **point of connection** to the **grid**; and

~~(b) **electricity** supplied from an **intermittent generating station** with a **point of connection** to the **grid**; and~~

(c) **electricity** supplied from a **type B industrial co-generating station** with a **point of connection** to the **grid**.

(2) To avoid doubt, each **generator** must give the relevant **grid owner** the **half-hour metering information** required under this clause in accordance with the requirements of Part 15 for the collection of the **generator's volume information**.

(3) If the **half-hour metering information** is not available, the **generator** must give the relevant **grid owner** a reasonable estimate of such data.

*This note is not part of the proposed Code*

**Note: Amendment to clause 13.137**

The proposed amendment to clause 13.137 is discussed in the note below following the proposed changed to clause 13.141.

…

**13.139 Half-hour metering information part of input information**

The adjusted **half-hour metering information** provided under clauses 13.136 to 13.138A forms part of the input information in the formula in clause 13.141(1)(b)(i).

…

**13.141 Pricing manager to use certain input information**

(1) The **pricing manager** must use the following **input information**:

(a) for existing generation configuration—

(i) data specifying the instantaneous **MW injection** at the **grid injection point** at the beginning of each **trading period** for each **generating plant** and each **generating unit** that was the subject of **offers** for that **trading period**; or

(ii) if no such data is available, a reasonable estimate of such data:

(b) for actual **demand** over the **trading period**,—

(i) the **demand half-hour metering information** described as $L_{MA}$ below must be calculated as follows:

$L_{MA} = G_{EA} + L_{MX} - L_{DCLS}$ (for a **grid exit point**)

$L_{MA} = G_{EA} - L_{MI} - L_{DCLS}$ (for a **grid injection point**)

$L_{MA} = L_{MX} - L_{DCLS} - \underline{UG}\ \cancel{UIG_{EA}}$ (for ~~an **intermittent generating station** with a **point of connection** to the **grid**, and/or~~ **unoffered generation** from a **generating station** with a **point of connection** to the **grid**, and/or a **type B industrial co-generating station** with a **point of connection** to the **grid**)

where

$L_{MA}$ is the adjusted quantity of **electricity** measured in **MWh** by a **metering installation** at a **grid exit point** or **grid injection point**

$L_{MX}$ is the unadjusted **half-hour metering information** for the quantity of **electricity** measured in **MWh** at a **grid exit point**

$L_{MI}$ is the unadjusted **half-hour metering information** for the quantity of **electricity** measured in **MWh** at a **grid injection point**

$L_{DCLS}$ is the adjusted **half-hour metering information** for the quantity of **electricity** measured in **MWh** used by a **dispatch-capable load station** for the **trading periods** that the **system operator** listed under clause 13.138B

$G_{EA}$ is the adjusted **half-hour metering information** given to the relevant **grid owner** under clause 13.136

UG ~~$UIG_{EA}$~~ is the information given to the relevant **grid owner** under clause 13.137:

(ii) if any of the **half-hour metering information** is not available, an **initial estimate** for each **grid exit point** or **grid injection point**:

(iii) to avoid doubt, each **grid owner** must provide the **half-hour metering information** to the **pricing manager** required under this clause in accordance with Part 15 for the collection of that **grid owner's volume information**:

(c) the final **offers** for each **trading period** submitted by **generators** and provided to the **pricing manager** by the **system operator** in accordance with clause 13.63:

(caa) the potential output of a **dispatched intermittent generating station** for each **trading period**, determined as follows:

(i) if **dispatch instructions** relating to the **intermittent generating station** were not **flagged** for more than half of the **trading period**, using the adjusted **half-hour metering information** for the **trading period** given to the relevant **grid owner** under clause 13.136:

(ii) if **dispatch instructions** relating to the **intermittent generating station** were **flagged** for more than half of the **trading period**, using the greater of—

(A) the **forecast of generation potential** specified in the **intermittent generator's** final **offer** for the relevant **intermittent generating station** for the **trading period** submitted under clause 13.18A; and

(B) the adjusted **half-hour metering information** for the **trading period** given to the relevant **grid owner** under clause 13.136:

(ca) the final **nominated dispatch bid** for each **dispatch**-**capable load station** (other than a **dispatch**-**capable load station** for which the final **nominated bid** for the **trading period** was a **nominated non**-**dispatch bid**) dispatched in each **trading period** that was provided to the **pricing manager** by the **system operator** in accordance with clause 13.63:

(d) the final **reserve offers** for each such **trading period** as given by **ancillary service agents** in accordance with clauses 13.37 to 13.54:

(e) the final information provided to the **system operator** by a **grid owner** under clauses 13.29 to 13.34 for each **trading period** that the **system operator** notifies in accordance with clause 13.63.

(1AA) The **pricing manager** must remove all **offers** from the following **participants** from the information specified in subclause (1)(c) before using it in the pricing process:

~~(a) **intermittent generators**; and~~

(b) **type B co-generators**.

(1A) Each **grid owner** must give the **pricing manager** the information the **pricing manager** is required to use under subclause (1)(a)—

(a) by 0730 hours on each **trading day**; and

(b) for each **trading period** of the previous **trading day**; and

(c) in the manner and form agreed by the **pricing manager** and each **grid owner**.

(2) Each **grid owner** must give the information required by subclause (1)(b) to the **pricing manager** by 0730 hours on a **trading day** for each **trading period** of the previous **trading day**. Each **grid owner** must provide this information in the form specified by the **pricing manager**.

(3) The **pricing manager** must **publish** the information by 1000 hours on a **trading day** for each **trading period** of the previous **trading day**.

(4) If the **pricing manager** receives revised demand **half-hour metering information** in accordance with clauses 13.146(1) and 13.154(1A)(b), and if the revised information resolves a **provisional price situation**, the **pricing manager** must **publish** the revised demand **half-hour metering information** no later than the time at which it is required to **publish interim prices** and **interim reserve prices**.

(5) If the **pricing manager** receives revised information after it has **published** information in accordance with subclause 3, it must **publish** the revised information by replacing the previously **published** information with the revised information.

*This note is not part of the proposed Code*

**Note: Formulas in 13.141(1)(b)(i) and the half hour metering information in clauses 13.136 and 13.137**

For calculating prices, the pricing schedule needs certain information about every entity (generator, electricity user) connected to the system. That information can come from "orders" (e.g. bids, offers), or from measured flow (injection, offtake). The purpose of subclause 13.141(1)(b)(i) is to calculate the measured flow for those entities for which we do not have orders. The information available for making that calculation is:

1) the grid metered quantities ($L_{MX}$ and $L_{MI}$)
2) the metered quantities associated with entities for whom order quantities are used ($G_{EA}$ and $L_{DCLS}$)
3) the metered quantities associated with entities for whom metered quantities are used, where these metered quantities do not contribute to the grid metered quantities. This occurs where an unoffered or intermittent generator is not located behind the grid meter ($UIG_{EA}$).

The formulas allow the pricing manager to calculate $L_{MA}$ (the "adjusted quantity") which is the measured flow for all those entities at the grid exit point (GXP) or grid injection point (GIP) for which we do not use orders for pricing.

The first formula ($L_{MA} = G_{EA} + L_{MX} - L_{DCLS}$) applies at a GXP. $L_{MA}$ is equal to the metered outflow from the grid at the GXP ($L_{MX}$) adjusted to reverse out the metered generation or load from entities for which the pricing manager uses order information ($G_{EA}$ for offered generators and $L_{DCLS}$ for dispatched loads).

The second formula ($L_{MA} = G_{EA} - L_{MI} - L_{DCLS}$) applies at a GIP. $L_{MA}$ is equal to the metered outflow from the grid at the GIP ($-L_{MI}$) adjusted to reverse out the metered generation or load from entities for which the pricing manager uses order information

($G_{EA}$ for offered generators and $L_{DCLS}$ for dispatched loads).

The third formula ($L_{MA} = L_{MX} - L_{DCLS} – UIG_{EA}$) applies when there is unoffered or intermittent generation at a GXP which is configured in such a way that its generation does not flow through the grid meter ($L_{MX}$), but is metered separately ($UIG_{EA}$). $L_{MA}$ is equal to the metered outflow from the grid at the GXP ($L_{MX}$), plus the metered outflow from the grid to the unoffered/intermittent generators ($-UIG_{EA}$), adjusted to reverse out the load from entities for which the pricing manager uses order information ($L_{DCLS}$ for dispatched loads).

In this system, wind generators are "treated as negative load". This treatment is put into effect by:

1) requiring the pricing manager, in clause 13.141(1AA), to discard offers from intermittent generators
2) excluding wind generation from the measurement of $G_{EA}$. The information that feeds into $G_{EA}$ is covered in clause 13.136. Note that clause 13.136(2) acts to exclude wind generation.
3) including wind generation in the measurement of $UIG_{EA}$. The information that feeds into $UIG_{EA}$ is covered in clause 13.137

Under the proposal, the pricing manager would move to use orders (offers) for wind generators. Consequently the proposal would:

1) remove the requirement in subclause 13.141(1AA) to discard wind offers from the pricing process. This means that wind offers would be used in the pricing process in accordance with subclause 13.141(1)(c)
2) add a new subclause 13.141(1)(caa) which requires the pricing manager to use the potential output of the wind farm. This potential output acts as a constraint on the scheduling of the wind farm in the final pricing schedule
3) amend clause 13.136 so that metered offered wind generation is <u>in</u>cluded in $G_{EA}$
4) amend clause 13.137 so that metered offered wind generation is <u>ex</u>cluded from $UIG_{EA}$. As a consequence the name "UIG" in clause 13.141(1)(b) needs to be changed to "UG" to reflect what is covered. The subscript "$_{EA}$" is not helpful and can also be dropped. The description following the third formula in subclause 13.141(1)(b)(i) would be amended to reflect these changes.

…

**13.192 Constrained off situations may occur**

A **constrained off situation** occurs when—

(a) a **generator** is not given a **dispatch instruction**, or is not dispatched by the **system operator** to the level expected based on the **generator's offer** compared to the relevant **final price**, for a **trading period** despite the **generator** having offered **electricity** at a price below the **final price** for that **trading period** at the relevant **grid injection point**; or

(b) in relation to a **block dispatch group** or **station dispatch group**, a **generator** is not given a **dispatch instruction**, or is not dispatched by the **system operator** to the level expected based on the **generator's offer** compared to the **final price**, for the **trading period**, despite the **generator** having offered **electricity** in the **trading period** at a **grid injection point** within the **block dispatch group** or **station dispatch group** below the **final price** at the relevant **grid injection point** in that **trading period**, and the aggregate quantity of those **offers** is greater than the dispatched quantity calculated in accordance with clause 13.194; or

(c) in relation to a **dispatch**-**capable load station** (except when the final **nominated bid** for the **dispatch**-**capable load station** in a **trading period** is a **nominated non**-**dispatch bid**), the latest **dispatch instruction** issued by the **system operator** for the **dispatch-capable load station** for a **trading period** is for a **MW** amount that is less than the **MW** amount scheduled for the **dispatch-capable load station** in the schedule of **final prices** for the **trading period**.

### 13.192A No constrained off situation for intermittent generating stations

Despite clause 13.192, no **constrained off situation** arises in relation to an **intermittent generating station**.

*This note is not part of the proposed Code*

**Note: Constrained on and constrained off payments to wind generators**

It is proposed to pay constrained on amounts, but not constrained off amounts, to wind generators. This matches the payments made to other generators.

There would be one difference between constrained on/off arrangements for wind generators and arrangements for other generators. The difference is that, while constrained off amounts are calculated (but not paid) to other generators, they would not even be calculated for wind generators. This reflects the additional complexity of calculating constrained off amounts for wind farms, since those amounts would depend on the wind farm's forecast of generation potential (from their final offer) as well as their offer bands. It also reflects the uncertainty about what a wind generator could have produced if it had not been dispatched down.

…

# Schedule 13.1

…

**Form 2**
**Intermittent Generator Offer**

Date: ________________________________________

Intermittent Generator Participant Identifier: ________________________________________

Intermittent Generator Name: ________________________________________

Grid Injection Point: ________________________________________

Generator category (clause 13.10 of the Code):☐ Station

Generator Installed Capacity: ________________________________________**MW**

Trading Period: _______ Starting at ________ : _______ 0 hours

Maximum Generator Ramp Up Rate: ____________________________________**MW**/hr

Maximum Generator Ramp Down Rate: ____________________________________**MW**/hr

**Offer to sell electricity**

Band 1: **From 0 MW to** ____________ **MW @ $** ____________ **per MWh**

Band 2: **plus** ________________ **MW @ $** ______________ **per MWh**

Band 3: **plus** ________________ **MW @ $** ______________ **per MWh**

Band 4: **plus** ________________ **MW @ $** ______________ **per MWh**

Band 5: **plus** ________________ **MW @ $** ______________ **per MWh**

**Forecast of generation potential:** ________________________________________ **MW**

…

# Schedule 13.3
# The Modelling System

**cls 13.29, 13.33, 13.57, 13.58, 13.69, 13.83, 13.87, 13.88, 13.90, 13.135, 13.193, and 13.203**

…

**6 Schedule of real time prices**

(1) For a schedule of **real time prices**, the schedule must use—

(a) the final information for each **real time pricing period** provided to the **system operator** under subpart 1 of Part 13, including—

(i) **offers** revised under clause 13.19; and

(ii) **nominated dispatch bids** revised under clause 13.19A; and

(iii) **reserve offers** revised under clause 13.47; and

(iv) information updated under clause 13.34(1); and

(v) the potential output of a **dispatched intermittent generating station** determined in accordance with subclause (2); and

(b) existing generation configuration specifying the instantaneous **MW injection** at each **grid injection point** at the beginning of the relevant **real time pricing period** for **generating plant** or **generating units** that were the subject of **offers** for the relevant **trading period**, or, if no such information is available, a reasonable estimate of such data; and

(c) existing **demand** configuration, specifying the average **MW demand** at each **grid exit point**, excluding the **MW demand** at each **dispatch-capable load station** for which a **nominated dispatch bid** is submitted at the **grid exit point**, during the relevant **real time pricing period**, or if no such information is available, a reasonable estimate of such data.

(2) For the purposes of subclause (1)(a)(v), the **system operator** must determine the potential output of a **dispatched intermittent generating station** using the following information:

(a) if the relevant **dispatch instruction** relating to the **intermittent generating station** is not **flagged**, the output of the **intermittent generating station** for the **real time pricing period** according to the **SCADA** 5 minute average (specified in **MW**); or

(b) if the relevant **dispatch instruction** relating to the **intermittent generating station** is **flagged**, the greater of—

(i) the **forecast of generation potential** specified in the relevant **intermittent generator's** final **offer** for the relevant **intermittent generating station** for the **trading period** submitted under clause 13.18A; and

(ii) the output of the **intermittent generating station** for the **real time pricing period** according to the **SCADA** 5 minute average (specified in **MW**); or

(c) if the **intermittent generator** and the **system operator** have agreed in advance that an alternative estimate may be provided, the alternative estimate of the potential output of the **intermittent generating station** for the **real time pricing period** provided by the relevant **intermittent generator**.

(3) For the purposes of subclause (2), relevant **dispatch instruction** means—

(a) the first **dispatch instruction** issued during the **real time pricing period** that relates to the **intermittent generating station**; or

(b) if no **dispatch instruction** was issued during the **real time pricing period** that relates to the **intermittent generating station**, the most recent **dispatch instruction** that relates to the **intermittent generating station**.

## 7 Dispatch schedule

For a **dispatch schedule**, the schedule must use—

(a) **offers** and **reserve offers**, excluding the following:

~~(i) **offers** made by an **intermittent generator** under clause 13.6(3):~~

~~(ii) revised **offers** made by an **intermittent generator** under clause 13.17(3):~~

(iii) **offers** made by a **type B co-generator** under clause 13.6(1) or (2):

(iv) revised **offers** made by a **type B co-generator** under clause 13.17(1) or (2); and

(b) the quantities specified in **nominated bids** (clause 13.7 and 13.7AA) and the quantities specified in revised **nominated bids** (clause 13.19A); and

(c) the expected profile of demand until the next **dispatch schedule** is produced by the **system operator**; and

~~(d) the ramp rates agreed for **intermittent generators** under clause 13.71(c); and~~

~~(e) any additional information regarding the future output of an **intermittent generator**, submitted by an **intermittent generator** in agreement with the **system operator** for the period until the next **dispatch schedule** is produced (clause 13.71(e)); and~~

(ea) the potential output of all **intermittent generating stations**, determined in accordance with clause 13.71(3); and

(f) the current output levels of each **generator**; and

(g) information from the **grid owner** (clauses 13.29 to 13.34) and revised information from the **grid owner** (clause 13.33) about—

(i) the AC transmission system configuration, capacity and losses; and

(ii) the capability of the **HVDC link** including its **configuration**, capacity, **losses**, the direction of any transfer limit, and any minimum or maximum transfer limits; and

(iii) transformer configuration, capacity and losses; and

(h) information about **voltage support**; and

(i) adjustments required to meet the **dispatch objective** must be incorporated in each schedule prepared and this method repeated until the **system operator** is satisfied that the schedule meets the requirements of the **dispatch objective**.

…

## 9 Constraints

In maximising the objective function, the **system operator** or the **pricing manager** (as the case may be) must ensure that the following constraints are met to an accuracy specified in the **model formulation**:

(a) *[Revoked]*

(b) each constraint relating to **generation** set out in clause 9A:

(c) the constraint relating to **demand** set out in clause 10:

(d) each constraint relating to the transmission system set out in clause 11:

(e) each constraint relating to **instantaneous reserve** set out in clause 12.

**9A Constraints relating to generation**

The constraints for the purpose of clause 9(b) are that—

(a) for each price band, the modelling system does not schedule **electricity** generation that would result in the scheduled quantity of **electricity** to be generated by a **generator** being greater than the quantity offered by the **generator** for the price band; and

(b) the modelling system schedules **electricity** generation for each **generating unit** or **generating station** in a **trading period** within the offered maximum ramp up and ramp down rates of the **generating unit** or **generating station**, given the expected (or actual) output at the start of the **trading period**~~.~~; and

(c) the modelling system schedules **electricity** generation for each **intermittent generating station** in a **trading period** at a level that is no higher than the potential output of the **intermittent generating station**, determined as follows:

(i) in relation to the **price-responsive schedule**, in accordance with clause 13.58A(1)(aa):

(ii) in relation to the **non-response schedule**, in accordance with clause 13.58A(2)(aa):

(iii) in relation to the **dispatch schedule**, in accordance with clause 13.71(3):

(iv) in relation to the **input information** referred to in clause 13.141, in accordance with clause 13.141(1)(caa):

(v) in relation to the schedule of **real time prices**, in accordance with clause 6(2).

…

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

# Appendix B Format for submissions

| Submitter | |
|---|---|

| Question | | Comment |
|---|---|---|
| Q1. | Do you agree the issues identified by the Authority warrant changes to the offer arrangements for wind generation? | |
| Q2. | Do you agree with the objectives of the proposed amendment? If not, why not? | |
| Q3. | Do you agree that an unsignalled generation withdrawal limit of 30 MW allows sufficient wind farm operational flexibility and does not cause unintended consequences for wind farm owners? | |
| Q4. | Do you agree the benefits of the proposed amendment outweigh its costs? | |
| Q5. | Do you agree the proposed amendment is preferable to the other option? If you disagree, please explain your preferred option in terms consistent with the Authority's statutory objective in section 15 of the Electricity Industry Act 2010. | |
| Q6. | Do you agree the Authority's proposed amendment complies with section 32(1) of the Act? | |
| Q7. | Do you have any comments on the drafting of the proposed amendment? | |

# Glossary of abbreviations and terms

| | |
|---|---|
| **Act** | Electricity Industry Act 2010 |
| **Authority** | Electricity Authority |
| **Code** | Electricity Industry Participation Code 2010 |
| **MW** | Megawatt(s) |
| **MWh** | Megawatt-hour(s) |
| **NRS** | Non-response schedule |
| **PRS** | Price responsive schedule |
| **RTD** | Real-time dispatch (schedule) |
| **RTP** | Real-time pricing (schedule) |
| **SCADA** | Supervisory control and data acquisition. A system for monitoring and controlling the power system. |
| **SRMC** | Short run marginal cost |
| **WAG** | Wholesale Advisory Group |