Issues and options paper:

Review of forecasting provisions for intermittent generators in the spot market

14 June 2023

ELECTRICITY AUTHORITY
TE MANA HIKO

Executive Summary

Background

In October 2022, the Electricity Authority (the Authority) published an information paper that investigated the accuracy of wind generation and demand forecasts and bids leading up to real time over the 12-month period from April 2021 to March 2022. The Authority observed that intermittent generation forecasts are often inaccurate and unreliable until close to real time. There was no material improvement in the accuracy of wind generation forecasts until three and a half hours before real time.

Over forecasting by wind generators was a contributing factor in the 9 August 2021 grid emergency,[1] which resulted in the disconnection of approximately 34,000 customers without warning.

Nature of the problem

Inaccurate intermittent generation forecasts create uncertainty for other participants, who need to make generation or consumption decisions ahead of real time. Inaccuracy may particularly affect participants who need advance notice to make generation or consumption decisions (eg, thermal generators and industrial demand-side participants).

Inaccurate forecasting is prevalent partly because there are limited statutory obligations around the accuracy of intermittent generation forecasts. Intermittent generators have few incentives to forecast accurately as there is little correlation between forecasting accuracy and revenue earnt in the spot market. This is particularly the case for intermittent generators who do not own other generation assets (eg, hydro) and do not have a retail arm.

Ernst & Young has undertaken an analysis to determine the impact that inaccurate intermittent generation forecasts have on electricity system costs. Based on trading periods between 1 November 2019 and 31 October 2022, this analysis established that:

a) under forecasting of wind, which occurred 32.5 percent of the time, resulted in an average impact on spot prices of -$6.90/MWh – equivalent to a $94 million annual impact on spot prices

b) over forecasting of wind, which occurred 67.5 percent of the time, resulted in an average impact on spot prices of $3.77/MWh – equivalent to a $107 million annual impact on spot prices.

Using the data from this analysis, the Authority determined that when considering demand and forecast prices 12 hours before real time, the annual impact that under forecasting has on spot prices increases from -$94 million to -$133 million annually. The annual impact that over forecasting has on spot prices increases from $107 million to $273 million annually.

The Authority has calculated that:

a) the estimated deadweight loss due to the price impact of wind forecast error is approximately $960,000 per annum

b) the productive efficiency costs due to the price impact of wind forecast error is approximately $2.2 million per annum.

[1] https://www.mbie.govt.nz/dmsdocument/17988-investigation-into-electricity-supply-interruptions-of-9-august-2021

A key takeaway from the analysis is that inaccurate forecasts send the wrong price signals to the market, which impacts participants' generation and consumption decisions. This may result in the following adverse consequences for consumers:

a) Risks to security of supply

b) Inefficient use of resources

c) Inefficiency in forward prices

d) Limited benefits of demand-side participation.

It is estimated that the share of supply from intermittent generation will increase from around 6 percent of total generation today to 47 percent by 2050.[2] In the shorter term, 78 percent of actively pursued projects that could be completed by 2025 are solar projects, with wind projects accounting for most of the remaining generation potential.[3] Over the next decade, the number of intermittent generators entering the New Zealand market is also expected to increase considerably.[4]

To date, it is likely that inaccurate forecasts have had a significant impact on thermal generators' unit commitment decisions. However, as the proportion of intermittent generation sources increases over time, thermal plants retire, and demand-side participation increases, the focus will gradually shift to the impact that inaccurate forecasts has on other generators' and demand-side participants' commitment decisions.

For the reasons outlined above, the Authority considers it an appropriate time to review the forecasting arrangements for intermittent generators.

Proposed policy solutions under consideration

Forecasting arrangements fall into the following camps:

a) <u>decentralised arrangements</u> where individual generators are responsible for their own forecast in its entirety (ie, both price and quantity elements)

b) <u>centralised arrangements</u> where a service provider is responsible for forecasting the likely intermittent generation quantities available (albeit with extensive data inputs provided by generators).

New Zealand currently uses a decentralised approach, with generators having the responsibility to provide forecast generation levels for scheduling and dispatch purposes.

Based on a review of the intermittent generation forecasting arrangements in other jurisdictions,[5] there are broadly four types of forecasting arrangements:

1) Decentralised forecasting responsibility

2) Centralised forecasting responsibility

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[2] https://www.ea.govt.nz/documents/1005/01-100-Renewable-Electricity-Supply-MDAG-Issues-Discussion-Paper-1341719-v2.4.pdf

[3] https://www.ea.govt.nz/documents/2156/Information-paper-Generation-Investment-Survey-2022-Concept-Consulting-.pdf

[4] https://www.ea.govt.nz/documents/2156/Information-paper-Generation-Investment-Survey-2022-Concept-Consulting-.pdf

[5] This includes Alberta, Australia, Texas, Ireland, Great Britain, and European Union member states.

3) Centralised with option for self-forecasting (ie, a hybrid model)
4) Compulsory ahead market and balancing market (could be implemented as part of a centralised or decentralised model).

In this paper, the Authority has evaluated the merits of each option against the status quo based on a set of criteria.

Based on this evaluation, it appears that all options would be an improvement on the status quo (in this assessment, the decentralised model included standards and incentives). This observation is supported by the fact that other jurisdictions that have adopted other forms of forecasting arrangements for intermittent generators are generally performing better than New Zealand in terms of forecast accuracy and minimising subsequent impacts on other market participants and the electricity system.

A centralised forecasting arrangement and a centralised arrangement with the option for self-forecasting both scored the highest when considering all evaluation criteria, followed by a decentralised arrangement with incentives/standards. The ahead and balancing market option scored the lowest, primarily because it would take a long time to implement and would be costly and complex.

Next steps

The Authority welcomes responses from interested parties on the consultation questions outlined in this paper.

If a decision is made to proceed with:

- a decentralised forecasting arrangement with incentives/standards (option one), the Authority will publish a consultation paper on proposed Code changes
- a centralised forecasting arrangement (option two) or hybrid approach (option three), the Authority will publish a Request for Information to determine which parties could potentially offer a centralised forecasting service, followed by a Registration of Interest and Request for Proposal.

The Authority does not propose implementing an ahead market and balancing market (option four), given it would be a significant undertaking to retrofit the existing market to achieve benefits that could be achieved through a different forecasting regime. However, the Authority welcomes submitters' views on this.

The Authority will keep interested parties updated via its Market Brief.

The Authority's preference, at this stage (subject to submissions), is to implement a policy solution by winter 2024.

Before the implementation of any option, the Authority will publish a decision paper outlining the option the Authority has decided to implement and the reasons why.

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1. Purpose

1.1. The purpose of this paper is to consult with interested parties on the issue of uncertainty in intermittent generation forecasts and proposed solutions to improve the accuracy and frequency of intermittent generation forecasts in the spot market.

1.2. This paper discusses forecasting arrangements that are used in other jurisdictions, including the relative advantages and disadvantages of each. It also outlines the principles that the Authority thinks should underpin any policy solution, as well as certain design considerations to help determine how each forecasting arrangement would be implemented.

1.3. Depending on responses from submitters, the Authority will do one of the following in the second half of 2023:

(a) publish a consultation paper on the details of a specific option to gauge further information from submitters; or

(b) publish a decision paper outlining the option the Authority has decided to implement and the reasons why.

2. Submissions

2.1. The Authority's preference is to receive submissions in electronic format. Submissions in electronic form should be emailed to **forecasting@ea.govt.nz**.

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

(a) indicate in a cover note which part/s should not be published;

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

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

2.3. If you indicate there is part of your submission that should not be published, the Authority will discuss with you before deciding whether to not publish that part of your submission. 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. The Authority will consult with you before releasing any material that you have said should not be published.

2.4. Please deliver your submissions by **5pm on Wednesday 26 July**.

2.5. This deadline allows six weeks for submissions. The Authority will acknowledge receipt of all submissions electronically. Please contact forecasting@ea.govt.nz if you do not receive electronic acknowledgement of your submission within two business days.

3. Problem definition

Intermittent generation is not always accurately forecast which is affecting participants’ ability to make generation or consumption decisions ahead of real time

3.1. Intermittent sources of generation[6] are those where the electrical output of generation depends on factors outside the generators' control. Therefore, any electricity offered into the spot market that is generated from intermittent sources is based on forecasts. In New Zealand, intermittent generators are responsible for generating and submitting forecasts.

3.2. Other forms of generation, such as hydro[7] and thermal generation, are controllable which enables owners and operators of these generation plants to ensure their offers[8] into the spot market accurately reflect the generation that is available for dispatch.

3.3. In October 2022, the Authority published an information paper[9] that investigated the accuracy of wind generation and demand forecasts and bids leading up to real time over the 12-month period from April 2021 to March 2022. This was in response to recommendations[10] following the 9 August 2021 grid emergency where over forecasting by wind generators was a contributing factor to this event. This is discussed later in the paper.

3.4. The Authority observed that that intermittent generation forecasts are often inaccurate and unreliable until close to real time.

3.5. Figure 1 shows that over a 12-month period from April 2021 to March 2022, there was no material improvement in the accuracy of wind generation forecasts until the last three and a half hours before real time. The improvement in accuracy three and a half hours ahead of real time aligns with when intermittent generators start submitting resource persistence forecasts.[11]

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[6] For the purposes of this paper, wind and solar are considered the main two forms of intermittent generation. There is a greater emphasis on wind in this paper given it has historically been the primary/only form of intermittent generation in New Zealand. However, the first grid-connected solar farm is expected to be operating in late 2023 and there is a large pipeline of new wind and solar farms that are expected to be built over the coming years.

[7] This includes run of river hydro as flows of water can be controlled to a degree by dams or by spilling water.

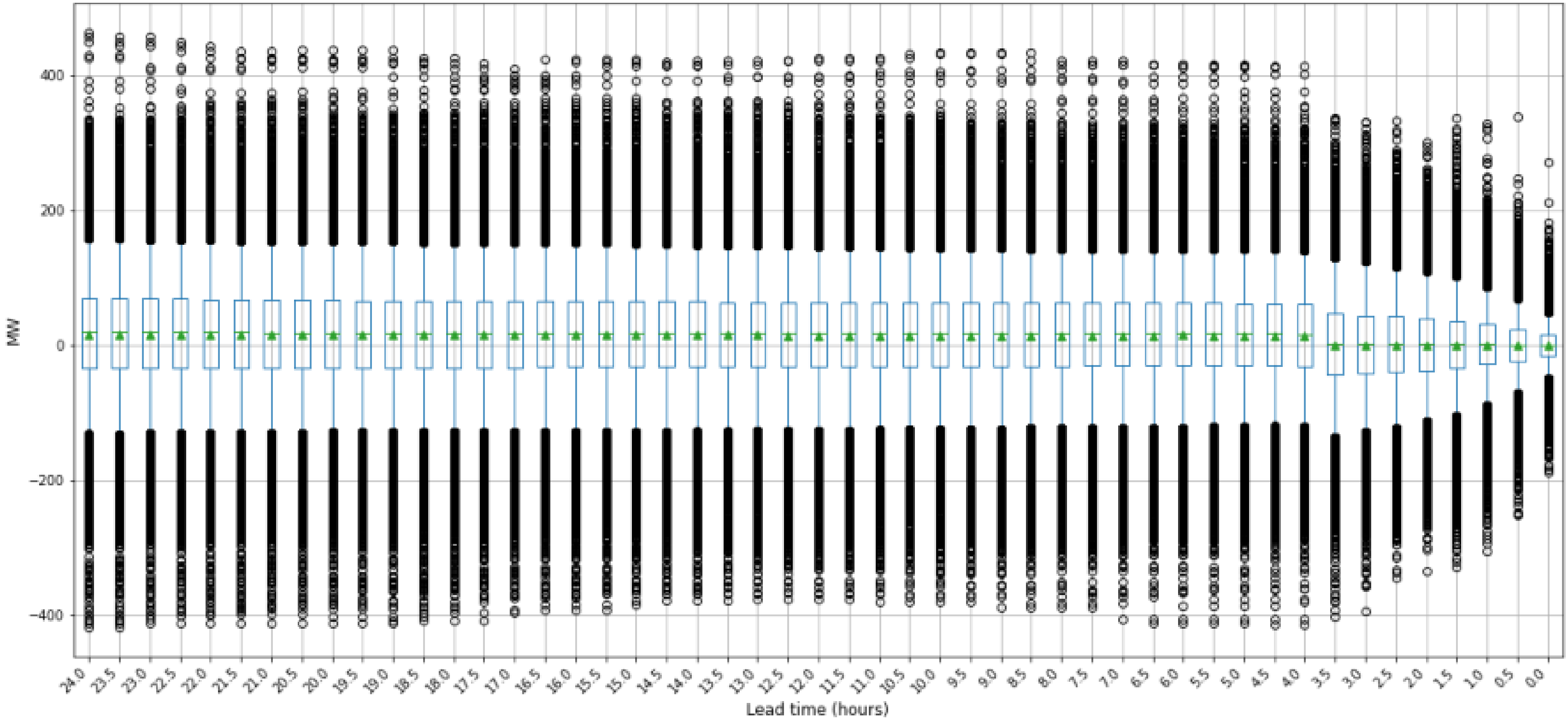
[8] Offers include both the quantity of generation and what it is priced at.

[9] https://www.ea.govt.nz/documents/2384/Accuracy-of-Wind-and-Load-Forecasts_jvF1BoL.pdf

[10] https://www.mbie.govt.nz/dmsdocument/17988-investigation-into-electricity-supply-interruptions-of-9-august-2021

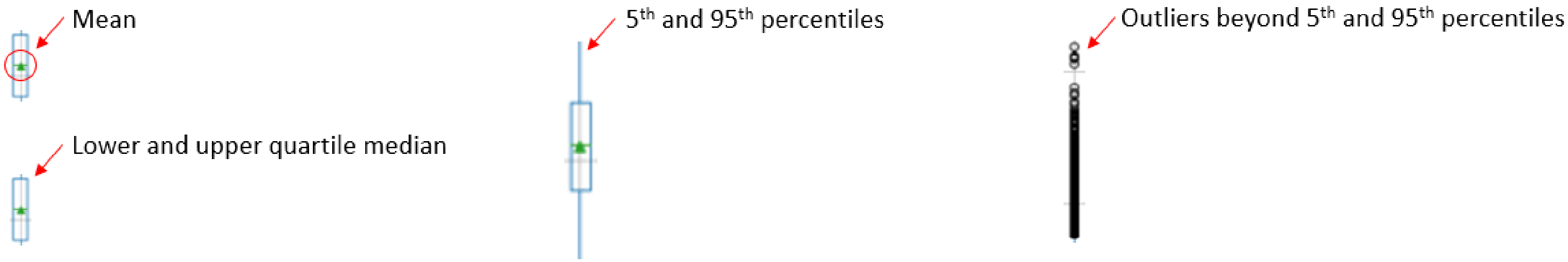
[11] Generators are not required to begin submitting resource persistence forecasts until the last two hours, but analysis Forecasts implies many begin about four hours before real-time.

Figure 1: Total wind generation forecast error over April 2021 to March 2022



Source: Electricity Authority

Key:



3.6. Inaccuracy prior to a few hours ahead of real time is prevalent because there are limited obligations in the Electricity Industry Participation Code 2010 (the Code) around the accuracy of intermittent generation forecasts.

3.7. Intermittent generators have few incentives to forecast accurately as there is little correlation between forecasting accuracy and revenue earnt in the spot market. This is particularly the case for intermittent generators who do not own other generation assets (eg, hydro) and do not have a retail arm.

3.8. Clause 13.18A(1) and (2) of the Code requires intermittent generators to submit a revised forecast of generation potential (FOGP) based on a resource persistence model (unless otherwise agreed with the Authority) during the two hours before immediately preceding the trading period to which the offer relates, with at least one revised forecast per trading period.[12]

3.9. Clause 13.18A(3) of the Code defines persistence forecasting as:

> *"a method for producing a forecast of the intermittent generator's generation for a trading period in MW, that is derived from the expected availability and capability of generating plant forming all or part of the relevant intermittent generating station, on the assumption that the variable resource conditions at the time at which the forecast is prepared will persist throughout the trading period to which the forecast relates."*

3.10. Inaccurate intermittent generation forecasts create uncertainty for other participants, who need to make generation or consumption decisions ahead of real time. Inaccuracy may particularly affect participants who need three and a half hours or more to make generation or consumption decisions (eg, thermal generators and industrial demand-side participants).

3.11. There is a risk that inaccurate intermittent generation forecasts may result in the following adverse consequences for consumers:

(a) <u>Risks to security of supply</u>: Participants offering to generate too little or consuming more electricity creates a risk to security of supply and may result in higher costs to consumers from addressing shortages of supply.

(b) <u>Inefficient use of resources</u>: Risk of participants offering to generate too much from expensive resources or consuming less electricity than actual conditions would suggest they were able to.

(c) <u>Inefficiency in forward prices</u>: Spot price volatility leading to higher risk premiums in forward prices.

(d) <u>Limited benefits of demand-side participation</u>: Demand-side participants not having enough time to reduce their load in times of short supply/high demand or reducing consumption unnecessarily if high prices do not materialise.

3.12. To date, it is likely that inaccurate forecasts have had a significant impact on thermal generators' unit commitment decisions. However, as the proportion of intermittent generation sources increases over time, thermal plants retire, and demand-side participation increases, the focus will gradually shift to the impact that inaccurate forecasts has on other generators' and demand-side participants' commitment decisions.

3.13. The Code requires all generators with a point of connection to the grid and greater than 10 MW of generation capacity to comply with offer requirements. The system operator can also require an embedded generator with an output greater than

[12] All intermittent generators currently use resource persistence forecasts.

10MW to submit market offers.[13] [14] The Code also requires all grid-connected generators who export 30 MW or more to comply with certain performance obligations and technical standards.[15] [16]

3.14. The Authority considers it important that a new forecasting arrangement – whether that be a decentralised or centralised arrangement – applies to all intermittent generators that are required to submit offers, whether grid connected or embedded generators required to submit offers by the system operator. This is because while a small generation plant only contributes a very small amount to New Zealand's total generation at any one time, the cumulative contribution of several smaller plants can be significant, including the implications if forecasts are inaccurate. As new intermittent generators, particularly solar generators, enter the market, there will be a greater number of plants with capacity between 10 and 30 MW exporting electricity to the grid.

3.15. Note that any new requirements would not apply to 'behind-the-meter' resources (i.e. resources that generate electricity primarily for individual purposes, such as rooftop solar).

Consultation questions:

Q1	Do you agree with the Authority's problem definition? If not, why not?
Q2	Do you agree that a new forecasting arrangement should apply to all grid-connected intermittent generators that are required to submit offers?

4. Timing and alignment with other projects

4.1. The Authority considers it to be an appropriate time to review forecasting provisions for intermittent generators as the potential adverse consequences are likely to increase as the proportion and amount of intermittent generation increases, and thermal generation plants retire.[17]

4.2. The Market Development Advisory Group (MDAG)[18] estimates the share of supply from intermittent generation will increase from around 6 percent of total generation today to 47 percent by 2050.[19] In the shorter term, based on results from a generation investment survey that Concept Consulting undertook the second half of 2022, 78 percent of actively pursued projects that could be completed by 2025 are

[13] Refer to clauses 8.25(5), 13.6(1) and 13.25 of the Code.

[14] In some situations, as determined by the system operator, embedded generators exporting more than 10 MW may also be required to comply with the necessary requirements to ensure security of supply (refer to clauses 8.25(5) and 13.6(1) of the Code).

[15] Refer to clause 8.21 of the Code.

[16] Part 1 of the Code also defines "major participants" as generators with aggregated national generation capacity in excess of 30 MW.

[17] Figure 17 in the Market Development Advisory Group's issues and discussion paper indicates that thermal generation may be needed until 2035.

[18] MDAG is made up of 10 representatives from the electricity sector. The purpose of MDAG is to provide independent advice to the Authority on issues in the Authority work programme that primarily relate to pricing and cost allocation, risk and risk management, and operational efficiencies.

[19] https://www.ea.govt.nz/documents/1005/01-100-Renewable-Electricity-Supply-MDAG-Issues-Discussion-Paper-1341719-v2.4.pdf

solar projects, with wind projects accounting for most of the remaining generation potential.[20]

Responding to recommendations following investigations of the 9 August 2021 grid emergency

4.3. In response to the 9 August 2021 grid emergency, a number of reviews and investigations were conducted, including several by the Authority, to:

(a) understand the causes of power supply interruptions

(b) understand the industry's response on the night

(c) learn lessons from the event to identify and recommend improvements to ensure similar circumstances are better managed in future.[21]

4.4. The reports from multiple investigations recommended that the Authority amend the Code to disallow persistence forecasting and require wind generations make more accurate offers to the system operator about supply.[22] This was in recognition that persistence forecasting can lead to intermittent generators significantly over forecasting wind generation when the wind is dropping.

4.5. As a first step to address these recommendations, the Authority investigated the accuracy of wind generation and demand forecasts and bids leading up to real time over the 12-month period from April 2021 to March 2022, and published its information paper in October 2022.[23]

4.6. While disallowing persistence forecasting may help to ensure intermittent generators make more accurate forecasts in the future, the Authority considers it practical to undertake a more comprehensive review of forecasting arrangements, including consideration of alternative forecasting provisions based on approaches in other jurisdictions.

MDAG's 'Price Discovery in a Renewables-Based Electricity System' project

4.7. MDAG has recently written an options paper focused on how price discovery would work in the New Zealand wholesale electricity market (including spot and hedge markets) in a renewables-based electricity system. The Authority published this paper for consultation between December 2022 and March 2023.[24]

4.8. A key theme in MDAG's options paper is ensuring reliable and efficient operational coordination. One option that MDAG has identified to achieve this objective is *'Improving short-term forecasts of wind, solar, and demand'.* This is in recognition that participants need good information to help make their plans in the lead-up to real time, and that forecasts up to 12 hours ahead of real time can be misleading and cause inefficiencies or reliability problems. MDAG also referenced that inputs to

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[20] https://www.ea.govt.nz/documents/2156/Information-paper-Generation-Investment-Survey-2022-Concept-Consulting-.pdf

[21] The Authority, the Ministry of Business, Innovation and Employment, and Transpower all carried out separate reviews. The Authority's initial report can be found here, the Ministry of Business, Innovation and Employment's report can be found here, and Transpower's report can be found here.

[22] Refer to recommendation IV on page 58 of the Ministry of Business, Innovation and Employment's report and recommendation IV on page 9 of the report commissioned by Transpower.

[23] https://www.ea.govt.nz/documents/2384/Accuracy-of-Wind-and-Load-Forecasts_jvF1BoL.pdf

[24] https://www.ea.govt.nz/projects/all/pricing-in-a-renewables-based-electricity-system/

the forecast schedules were a contributing factor to problems experienced during the 9 August 2021 grid emergency.

Boston Consultancy Group's 'Climate Change in New Zealand: The Future is Electric' report

4.9. The Boston Consultancy Group also recommended that there be a focus on improving forecasts for intermittent sources of generation in its October 2022 '*Climate Change in New Zealand: The Future is Electric'* report.[25]

Winter 2023 – Option D: System operator to publish island aggregate wind generation forecasts

4.10. In March 2023, in response to concerns about potential tight supply situations occurring in winter 2023, the Authority released a decision paper – '*Driving efficient solutions to promote consumer interests through winter 2023'*. As part of this project, the Authority considered 11 options constituting potential tool, process, and regulation changes that would improve wholesale market information and incentives to address the issue of "operational coordination" – ensuring installed resource is available to contribute to achieving an efficient level of reliability.

4.11. One of the options that the Authority decided to implement was 'Option D – system operator to publish island aggregate wind generation forecasts'.

4.12. The system operator procures a wind generation forecast to enable its system coordinators to make security assessments of system conditions and the likely accuracy of participant wind generation offers. Under previous arrangements, if the coordinator determined that a potential tight supply situation may occur and participant generation offers are materially higher than the generation forecast procured by the system operator, an industry briefing may be called, and the offer discrepancy highlighted. This aimed to focus the generators on re-evaluating their offers and ensure they are as accurate as they can be.

4.13. The first notice that participants receive that their offers may need to be reviewed is the industry briefing called by the system operator. Under Option D, the system operator's intermittent generation forecast is now published routinely via a public market information page. The data has been enhanced to include confidence levels in the forecast to highlight the certainty of the prevalent resource conditions and including the most recent generation offers for the forecast period.

4.14. By routinely publishing an island-aggregate generation forecast, with confidence intervals to signal the level of uncertainty in the forecast and participant offers, participants would be able to better assess the potential severity and probability of a tight supply situation earlier than waiting for an industry briefing from the system operator to publicise this information. The wind generators would remain entirely responsible for their offers, but their offers or the actions they may take with other generation plant in their portfolio would be timelier and better informed of the potentially uncertain system conditions.

4.15. This option was implemented in early May 2023 and is expected to be in place until the end of September 2023.

[25] Climate Change In New Zealand | The Future Is Electric | BCG

5. Impacts of over and under forecasting intermittent generation

Over forecasting can lead to risks to the security of supply

5.1. Over forecasting by intermittent generators creates risks to security of supply because it can lead to a shortfall in offered controllable generation.

5.2. Based on multiple reviews, over forecasting by wind generators was a contributing factor in the 9 August 2021 grid emergency. During the day the system operator received offers of just under 500 MW from wind generators. However, over the course of the evening peak, only 300 MW of electricity was able to be generated from wind generators. The energy shortfall and grid emergency contributed to the system operator instructing load management by the network companies and consequently disconnection of approximately 34,000 customers without warning.[26]

5.3. Scarcity pricing was also triggered which had a significant impact on prices. The gross settlement was approximately $130 million higher than it would have been if scarcity pricing was not triggered. Many generators and retailers are hedged so this figure may overstate the true economic impact.

5.4. During the grid emergency, inaccurate intermittent generation forecasts were a contributing factor towards thermal generators not having enough lead time to start up and reach full load to meet demand. Thermal generation needs 6-12 hours' notice to start up from cold and reach full load. When offering, thermal generators must assess the likelihood of being dispatched at a sufficient level, duration and price as start-up costs are significant. If slow start generators anticipate that their plant is not required and the generation/demand balance deteriorates, it may be too late for them to start up, leaving a shortfall in generation to meet demand.

5.5. Whilst the grid emergency was a rare event, inaccurate intermittent generation forecasts remain a risk to security of supply. There are ongoing costs to consumers from addressing threats to security of supply that do not necessarily result in grid emergencies, including the costs of using reserves, scarcity pricing and requesting distributors to shed discretionary load.

5.6. Over forecasting by intermittent generators also leads to general uncertainty amongst participants, who may not offer into the spot market unless they are confident that generation will be dispatched, or demand response is needed.

5.7. There is an opportunity cost associated with offering into the spot market and not being dispatched. The opportunity costs of generating without being sufficiently compensated to cover short run marginal costs are higher for expensive sources of generation. Therefore, general uncertainty may be more likely to create risks to security of supply when expensive sources of generation are needed to meet periods of high demand, or short supply (allocative inefficiency).

Under forecasting can lead to participants using resources inefficiently

5.8. Under forecasting by intermittent generators creates a risk of an inefficient use of resources (allocative inefficiency) in the following ways:

Unit commitment regret

5.9. Participants may regret offering generation or demand response if their resources are not required at real time. Generators may offer generation into the spot market that is not dispatched because there is more intermittent generation available at real

[26] https://www.mbie.govt.nz/dmsdocument/17988-investigation-into-electricity-supply-interruptions-of-9-august-2021

time than was signalled ahead of time, or demand response participants provide demand response unnecessarily as high prices do not materialise.

5.10. Unit commitment regret may result in an inefficient use of resources because generators bear the costs of generating without electricity being used, or demand-side participants reduce their electricity consumption when they could have otherwise consumed the electricity for productive uses. Inefficiency is not in the long-term interests of consumers as the costs of inefficiency may be passed on and result in higher prices for consumers.

5.11. Unit commitment regret is more likely for participants who need to make consumption or generation decisions more than a few hours ahead of real time and do not have the flexibility to ramp up or down quickly.

General uncertainty

5.12. General uncertainty in forecasts may affect the system operator's ability to ensure supply meets demand at all points in time. The system operator can use its discretion to dispatch higher levels of generation or demand response offered into the spot market above the market clearing price to ensure there is enough supply. Uncertainty in forecasts ahead of real time may mean that the system operator adds a margin for error in its discretion to dispatch more generation or demand response than is needed. This is a source of inefficiency as consumers may be paying for more electricity than is needed to balance the power system.

Inaccurate forecasts could lead to more inefficient forward prices

5.13. Uncertainty in intermittent generation forecasts makes spot prices more volatile than they otherwise would be if intermittent generation forecasts were more accurate. Volatility in spot prices may be caused by other participants not making generation and consumption decisions in a predictable way, and changeable resource conditions may cause sudden changes in intermittent generation close to real time which can affect prices.

5.14. Volatile spot prices could result in higher risk premiums in forward prices as forward prices are an expectation of future spot prices. This may result in higher costs for consumers.

Inaccurate forecasts may limit the benefits of demand-side participation

5.15. Inaccurate forecasts affect generation decisions, but they also affect demand response participants. Demand response can ease shortages of supply and lower wholesale prices through reducing consumption. However, the benefits of demand-side participation may be limited if inaccurate forecasts mean that:

(a) demand-side participants do not have enough time to reduce their load in times of short supply/high demand,

(b) demand-side participants reduce consumption unnecessarily if high prices do not materialise, or

(c) they do not have trust and have the confidence to participate in the spot market.

5.16. Demand-side participation has been limited in recent years. However, enhancements to dispatchable demand introduced in April 2023 as part of the Authority's Real Time Pricing Project will reduce barriers for providing demand response. The implementation of real time pricing means that:

(a) small providers are now able to formally bid their ability to respond to the wholesale market

(b) dispatchable demand participants may ask the system operator to model their load as binary load. This means load can only be dispatched in whole demand bid tranches. Previously, demand participants could be instructed to reduce consumption by a portion of a bid tranche, but some demand participants could only turn their industrial processes on or off

(c) there will be greater certainty over prices as final settlement prices are calculated at the end of each trading period, rather than at least two days after the trading period (which was the process before 1 November 2022).

5.17. Improving the accuracy of intermittent generation forecasts will improve demand response participants' trust and confidence to participate in the spot market. This will become increasingly important as the proportion of intermittent generation sources increases over time, particularly when there is a need to reduce peak demand when periods of high demand coincide with cold, calm, and/or cloudy conditions.

6. The Code specifies the responsibilities of intermittent generators, but these are limited and possibly ineffective

There are limited obligations and incentives in the Code for accurate intermittent generation forecasts

6.1. Inaccurate intermittent generation forecasts are prevalent because intermittent generators have few incentives to forecast accurately in the spot market and there are limited obligations in the Code for intermittent generators to forecast accurately.[27]

6.2. Intermittent generators have limited incentives to forecast accurately because there is little relationship between forecasting accurately and revenue earned from the spot market. As wind generation has a low marginal cost, wind generation is usually offered into the market at $0.01/MWh to increase the likelihood of it being dispatched, but the spot price will often be much higher than this. If intermittent generators' actual generation is higher or lower than their final offer, the system operator uses actual generation available at real time in their dispatch decisions.

6.3. However, it is important to recognise that incentives to provide accurate forecasts may differ across intermittent generators depending on factors including, but not limited to, intermittent generators' portfolio of generation assets and exposure to the spot market.

6.4. Intermittent generators with multiple types of generation assets may have a greater incentive to forecast accurately to coordinate offers and dispatch across generation assets. Most existing intermittent generators are generator-retailers who all own hydro generation assets in addition to wind generation. It can take up to a few hours for hydro generation to be available for dispatch which may in part explain why most intermittent generators forecast accuracy for most generators improves around three and a half hours ahead of real time. This coincides with when most generators start using persistence forecasts.

[27] Clause 13.86A(2) of the Code requires intermittent generators to provide a report to the Authority if an individual plant generates 30 MW or below the FOGP in the intermittent generator's final offer.

6.5. The degree to which an intermittent generator is hedged affects incentives to devote resources in the spot market as well. If an intermittent generator earns a guaranteed price per unit of output (eg, a power purchase agreement), there may be limited incentives to devote resources towards the spot market. If an intermittent generator does not have a firming plant (ie, where generation output can be controlled), it can be difficult for it to enter into hedging contracts because it cannot guarantee a certain level of generation in the future.

6.6. There are only a few obligations in the Code[28] related to how intermittent generators forecast in the spot market and some of those obligations may not be working as intended. The main issues with the forecasting obligations for intermittent generators in the Code are:

(a) There are no requirements or incentives in the Code around the frequency or accuracy of intermittent generation forecasts more than two hours ahead of a trading period. This affects participants who need to make consumption and generation decisions more than two hours ahead of real time.

(b) During the two hours before a trading period to which an offer relates, intermittent generators are required to submit a revised FOGP[29] based on a resource persistence model (unless otherwise agreed with the Authority) for every trading period.[30]

(c) The requirement for intermittent generators to submit a report to the Authority if an individual plant generates 30 MW or below the FOGP in their final offer may not be sufficient deterrent to protect against shortfalls in generation close to real time. The Authority receives a high number of reports each month, often with forecast errors above 30 MW.

(d) There are no disincentives for intermittent generators generating more than the amount signalled in forecasts close to real time.

6.7. Like other generators' obligations in the spot market, intermittent generators must submit an offer 71 trading periods ahead of the trading period to which the offer relates.[31] Unlike other generators, intermittent generators are excluded from having to revise offers ahead of real time if the offer exceeds by more than 5 MW, the MW that the generator expects to be able to generate in the trading period to which the offer relates.[32]

6.8. The limited requirements around accuracy and frequency of offers by intermittent generators possibly affects inflexible generators or demand side participants with long lead times. For example, some thermal generators require 6-12 hours to start up from cold and reach full load,[33] and large industrial users providing demand response may require several hours to slow down production.

6.9. There may also be benefits for other participants knowing how much intermittent generation is expected even further in advance. For example, an indication of

[28] Clause 13.18A of the Code specifies when intermittent generators must submit a revised FOGP.

[29] The FOGP is a forecast of the total output from a wind or solar farm summed over all five tranches within a trading period.

[30] Refer to 13.18A(3) of the Code.

[31] Refer to clause 13.6(b) of the Code.

[32] Clause 13.18 of the Code applies to generators other than intermittent generators. Clause 13.18A(1) applies to intermittent generators.

[33] The amount of notice needed varies between thermal units, including whether the unit is starting up from cold, warm or hot.

intermittent generation more than 71 trading periods in advance of real time may assist with planning and maintenance.

The Code requires intermittent generators to submit a revised FOGP every trading period in the last two hours ahead of the trading period to which the offer relates

6.10. There are currently no requirements or incentives in the Code around the frequency and accuracy of intermittent generation forecasts more than two hours ahead of a trading period.

6.11. The Code sets out that a revised FOGP must be submitted at least once per trading period in the last two hours ahead of real time and must be based on a resource persistence model, unless otherwise agreed with the Authority. Intermittent generators are not required to revise their offers to reflect the latest FOGP.

6.12. A resource persistence model is a method for producing a forecast of the intermittent generator's generation for a trading period that is derived from the expected availability and capability of generating plant, on the assumption that the variable conditions at the time of the forecast will persist throughout the trading period to which the forecast relates. This means that the forecast generation is based on immediate past generation, irrespective of any changes in actual wind availability in the time period that a resource persistence model applies to.

6.13. It appears most wind generators base their forecasts in the last few hours on a resource persistence model, rather than just in the last two hours before the relevant trading period.

Incentives for intermittent generators are not working as intended and are one-sided

6.14. At dispatch, the Code[34] requires intermittent generators not to generate electricity that is more than 30 MW below the FOGP in their final offer. The exception to this is if the intermittent generator is complying with an intermittent generator constrained flagged dispatch instruction, or other instruction, by the system operator or there is a bona fide physical reason.

6.15. If an intermittent generator fails to comply with this requirement for one or more trading periods in a calendar month, it is required to provide a report to the Authority no later than at the end of the next calendar month. The report must specify the trading periods to which the shortfall in generation relates to and an explanation of the reason.

6.16. This requirement prevents large, un-forecast reductions of generation creating risks to security of supply at short notice without imposing too strong an obligation on wind farms.[35]

6.17. Each month the Authority receives many reports. The high number of reports suggests that intermittent generators may not be appropriately incentivised to protect against large shortfalls in generation close to dispatch. As intermittent generation increases during the transition to a renewables-based electricity system,

[34] Refer to clause 13.86A of the Code.

[35] The requirement was added via the Electricity Industry Participation Code Amendment (Wind Offer Arrangements) 2019.

the number of breaches and magnitude of shortfalls is likely to increase, which poses a significant risk to security of supply.

6.18. Incentives for intermittent generators are currently one-sided. While clauses 13.86A(2) and 13.86A(3) impose obligations on intermittent generators if actual generation is 30 MW or more below forecast generation, there are no obligations in the Code for intermittent generators when actual generation is above forecasts. The Authority considers it is important to protect consumers against both potential inefficiencies when forecasts are below actual generation and security supply risks when forecasts are above actual generation.

6.19. The Authority is considering improving incentives for intermittent generators to forecast accurately and accuracy standards to ensure a degree of accuracy in forecasts.

The current requirements for revising offers are less strict for intermittent generators

6.20. The Code[36] requires generators that are not intermittent generators to immediately submit a revised offer to the system operator if 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.

6.21. As noted above, intermittent generators currently must not generate more than 30 MW below the FOGP in their final offer. The greater margin for intermittent generators reflects the inherent difficulty in accurately forecasting intermittent sources of generation.

6.22. As the proportion of and amount of intermittent generation increases over time, there is a need to consider whether there should be requirements for intermittent generators to revise their offers and brought more in line for the offer requirements that apply to other generators.

7. Intermittent generation forecasting arrangements – review of international jurisdictions

7.1. As part of this project, the Authority commissioned Concept Consulting to review the intermittent generation forecasting arrangements in other jurisdictions.

7.2. Concept looked at five overseas jurisdictions – Alberta, Australia, Texas, Ireland and Great Britain. Concept also investigated the forecasting arrangements in European Union member states.

7.3. The arrangements in Alberta, Australia, Texas, which Concept examined in the most detail, use an 'energy-only' design[37] for their wholesale market. New Zealand also uses an energy-only design, which suggests the lessons from those systems should be relatively applicable in New Zealand.

[36] Refer to clause 13.18 of the Code.

[37] In a market with an energy-only market design, a generator's only assured revenue source is from the sale of electricity into the wholesale spot market. Generators may also earn revenue from forward contracts. Under an energy-only market design, generators are free to choose the type of generation they produce and where their facilities are located.

7.4. Concept also wanted to ensure some diversity in the jurisdictions that were reviewed. The information from Great Britain and Ireland is useful in this respect because these systems have capacity markets,[38] rather than energy-only designs.

7.5. EU member states use a mix of approaches including energy-only and capacity mechanism approaches.

7.6. Forecasting arrangements fall into the following camps:

(a) <u>decentralised arrangements</u> where individual generators are responsible for their own forecast in its entirety (ie, both price and quantity elements)

(b) <u>centralised arrangements</u> where a service provider is responsible for forecasting the likely intermittent generation quantities available (albeit with extensive data inputs provided by generators).

7.7. New Zealand currently uses a decentralised approach, with generators having the responsibility to provide forecast generation levels for scheduling and dispatch purposes. New Zealand is an outlier in the following ways:

(a) compared to the other jurisdictions that were considered, New Zealand is the only jurisdiction with a purely decentralised regime (many EU members states have a decentralised regime, but this is implemented alongside an ahead and balancing market)

(b) the forecast horizon for intermittent generation in New Zealand is 36 hours ahead, which is much shorter than that in most other jurisdictions.

7.8. A summary of the forecasting arrangements in jurisdictions that were reviewed is outlined in Table 1.

[38] In a market with a capacity market design, generators are paid based on both the ability to produce electricity at certain times (eg, years into the future, or when demand is high), as well as the actual electricity produced. A capacity market imposes a compulsory contracting obligation on parties who purchase electricity in the spot market.

Table 1: Summary of forecasting arrangement in various jurisdictions

Jurisdiction	Responsibility for forecast quantities	Responsibility for economic inputs (offers)	Key usage	Forecast horizon
NZ	Decentralised	Decentralised	• Scheduling and dispatch • Generation capacity available for dispatch • Reserve requirements	Up to 36 hours ahead
Australia	Centralised	Decentralised	• Generation capacity available for dispatch • Reserve requirements	Up to 40 hours ahead (dispatch) and 7 days ahead (reserve assessment)
Alberta	Centralised	Decentralised	• Anticipating net demand for dispatch process • Forecast pool prices	Up to 7 days ahead
Texas	Centralised (two forecasters)	Decentralised	• Default (or maximum) capacity available for dispatch • Reliability unit commitment	Up to 7 days ahead
Great Britain	Centralised	Not entirely clear but expect it will be decentralised	• Publication for market participants • Scheduling of generation	Up to 14 days ahead
Ireland	Centralised (two forecasters)	Decentralised	• Scheduling and dispatch • Calculating unit lower operating limits • Publication for market participants	Up to 4 days ahead
EU	Decentralised	Decentralised	Positioning in ahead markets	Depends on participant

7.9. Concept's full report, which provides more detail about the forecasting arrangements in each jurisdiction and the relative advantages and disadvantages of each arrangement, is attached as Appendix 2. The report also discusses the successfulness of forecasting arrangements in some jurisdictions.

7.10. Sections 9 and 10 of this paper discusses the various forecasting arrangements and evaluates them against a list of criteria.

8. Qualitative and quantitative assessments of the impacts of inaccurate forecasts

8.1. As part of this project, the Authority commissioned Ernst & Young (EY) to undertake qualitative and quantitative assessments to determine the impact that inaccurate intermittent generation forecasts have on electricity system costs.

Summary of analysis

8.2. EY carried out a qualitative analysis based on the following three scenarios:

(a) a base case of near perfect wind forecasting accuracy

(b) an overestimation of a material amount of wind generation 12 hours ahead of the trading period

(c) an underestimation of a material amount of wind generation 12 hours ahead of the trading period.

8.3. A 12-hour period was selected because the system occasionally relies on slow start thermal generation units as energy sources, some of which require 6-12 hours to start up if they are required in a situation of tight supply.

8.4. EY's analysis, which included all trading periods between 1 November 2019 and 31 October 2022, established that:

(a) under forecasting of wind, which occurred 32.5 percent of the time, resulted in an average impact on spot prices of -$6.90/MWh – equivalent to a $94 million annual impact on spot prices

(b) over forecasting of wind, which occurred 67.5 percent of the time, resulted in an average impact on spot prices of $3.77/MWh – equivalent to a $107 million annual impact on spot prices.

8.5. A key takeaway from the analysis is that inaccurate forecasts send the wrong price signals to the market, which impacts participants' generation and consumption decisions (dynamic inefficiency).

8.6. While the impacts of under and over forecasting can be quantitively assessed and are relatively significant in terms of the dollar amounts, for the purposes of achieving the policy objective, it is more important to understand the effect that under and over forecasting has on the behaviour of market participants, and subsequently the flow on effect this has on consumers.

8.7. For example, under forecasting of wind generally results in a reduction in spot prices compared to forecast. While this may appear to be beneficial to consumers, it is important to note that consumers will typically bear the costs of this over the longer term. If wind is underestimated 12 hours ahead of real time, and therefore spot price is overestimated in the forward schedule, generators may make the decision to start-up slow-start expensive thermal generation as the price signals indicate it make economic sense to do so.

8.8. However, as the supply deficit does not eventuate and higher spot prices do not eventuate, prices in the period are not sufficient to cover the marginal cost of generation. Generators of slow-start thermal generation may introduce greater price buffers for unit commitment decisions or seek to recover their losses over future trading periods, which would tend to put upwards pressure on spot prices.

8.9. If intermittent generators consistently under forecast wind, this may impact the behaviour of slow-start thermal generators and other market participants who could become less inclined to offer into the market even when price signals indicate that it would make economic sense to do so. In situations where intermittent generators' forecasts are relatively accurate, this could then risk security of supply as there will be a need for additional generation to be called upon to make up the supply shortfall. This would generally result in expensive fast start thermal units or scarce hydro (which will likely be priced highly) being used.

Consultation question:

Q3	*Note this question is referring specifically to generators who have thermal assets:* For all trading periods between 1 November 2019 and 31 October 2022, how often do you think you made the incorrect decision whether to start or stop your thermal unit(s)? Please provide reasons why this occurred.

The Authority has undertaken further analysis to quantify the economic costs on the wider electricity system

8.10. EY's analysis primarily focuses on the impact from a change in price in wind forecasting error. In reality, there are lots of things that can change in the 12-hour window that can impact final spot prices (eg, other generation outages, generation being brought on, generation offers changing, demand forecasts changing, changes in run of river hydro, etc).

Considering periods of high and low demand

8.11. EY's analysis does not consider the time of day when under forecasting occurs (eg, during morning/evening peak periods compared to overnight). Therefore, the annual price increase and decrease due to over and under forecasting does not take into account periods of higher or lower than average demand.

8.12. The Authority has undertaken further analysis to understand how this dimension impacts electricity price and the total annual cost.[39] When considering demand and forecast prices 12 hours before real time, the annual impact that under forecasting has on spot prices increases from -$94 million to -$133 million annually. The annual impact that over forecasting has on spot prices increases from $107 million to $273 million annually.

Analysis based on demand simulations

8.13. The Authority has undertaken an analysis based on demand simulations to represent wind forecast errors. In this analysis, simulations with an increase in demand (compared to final demand) is equivalent to an under forecast in wind generation (ie, higher demand is equivalent to less wind generation), while the simulations with a decrease in demand are equivalent to an over forecast in wind generation (ie, more wind is forecast than what wind generation ends up being for the final price).

8.14. The analysis used data from all trading periods between 1 April 2021 and 31 March 2022. Demand simulations were restricting to trading periods where wind forecast error was higher than 23 MW one hour period than the trading period. 23 MW was chosen as the threshold as it is the average increase or decrease in demand in the simulations.

8.15. The analysis was done in a way that reflected that improving forecasting accuracy was possible, but perfect accuracy was not.

[39] Using data that included:

- total scheduling, pricing and dispatch demand by trading period from 1 Nov 2019 to 31 Oct 2022
- the long price-responsive schedule (PRSL) prices at WKM2201 (Whakamaru) published 12 hours before real time from 1 Nov 2019 to 31 Oct 2022.

8.16. The results of this analysis are as follows:

	Average price delta ($/MWh)	Percent of trading periods (%)	Annual cost ($ million)
Under forecasting	-6.9	29	-162
Over forecasting	6.9	31	173

Analysis based on pre-dispatch prices

8.17. The Authority also undertook an analysis using pre-dispatch prices to represent wind forecast errors. In this analysis, when the pre-dispatch price is lower than the final price, this indicates an over forecasting of wind (or under forecasting of demand). When the pre-dispatch price is higher than the final price, this indicates an under forecasting of wind (or over forecasting of demand).

8.18. The analysis looking at the impact of under forecasting of wind was restricted to trading periods where the wind forecasting error was negative (ie, wind was under forecast) and where the pre-dispatch price was greater than the final price both three and a half hours ahead of the trading period and one hour ahead.

8.19. The analysis looking at the impact of over forecasting of wind was restricted to trading periods where the wind forecasting error was positive (ie, wind was over forecast) and where the pre-dispatch price was less than the final price both three and a half hours ahead of the trading period and one hour ahead.

8.20. Like the analysis that used demand simulations, the analysis using pre-dispatch prices was also done in a way that reflected that improving forecasting accuracy was possible, but perfect accuracy was not.

8.21. The results of this analysis are as follows:

	Average price delta ($/MWh)	Percent of trading periods (%)	Annual cost ($ million)
Under forecasting	-16.5	16	-224
Over forecasting	5.5	32	141

Calculating the deadweight loss

8.22. The Authority has calculated that the estimated deadweight loss[40] due to the price impact of wind forecast error is approximately $960,000 per annum (note this does not account for other factors that impact spot prices, such as those listed in paragraph 8.10).

8.23. The deadweight loss represents the reduction in surplus due to changes in consumption because of distorted price signals. It also reflects:

[40] When supply and demand are out of equilibrium, creating a market inefficiency, a deadweight loss is created.

(a) the value of inefficient trade (where the marginal cost exceeds marginal utility due to prices being set below an efficient level)

(b) the value of efficient trade that failed to occur (due to prices being set above an efficient level).

Calculating the productive efficiency costs

8.24. The Authority has calculated that the productive efficiency costs[41] due to the price impact of wind forecast error is approximately $2.2 million per annum. This is generally caused by:

(a) more expensive generation being used when cheaper slow-start thermal generation fails to be committed due to over forecasting of wind, and is thus taken out of the supply stack

(b) slow-start thermal generation being offered into the market at a higher price to cover the risk of being committed when not required due to under forecasting of wind.

8.25. In addition to the effect that inaccurate forecasting has on spot prices, the key takeaway from the Authority's analysis is that it shows that inaccurate forecasting leads to market inefficiencies and has negative impacts on the wider electricity system.

9. Structure of forecasting arrangements

9.1. Based on the Concept Consulting's review of intermittent generation forecasting arrangements in other jurisdictions, the Authority considers there to be four types of forecasting arrangements that should be assessed against the status quo:

1) Decentralised with incentives/standards

2) Centralised

3) Centralised with option for self-forecasting (ie, a hybrid model)

4) Compulsory ahead market and balancing market (could be implemented as part of a centralised or decentralised model).

9.2. A description and consideration of the relative advantages and disadvantages of each approach is outlined below.

Decentralised forecasting with incentives/standards

Description

9.3. Like the status quo, intermittent generators would be responsible for submitting forecasts. The only change would be the introduction of incentives/accuracy requirements/standards in the Code.

Some advantages of this forecasting arrangement are:

9.4. Generators may have access to better information sources than a central agent. Provided generators have robust incentives, a decentralised approach should yield accurate forecasts. This would lead to greater trust and confidence in price signals, which would likely lead to lower costs for consumers in the long run.

[41] Productive efficiency refers to a level of maximum capacity in which all resources are being fully utilised to generate the most cost-efficient product possible.

9.5. Out of all options considered, this option would be the simplest to implement.

Some disadvantages of this forecasting arrangement are:

9.6. It may be difficult to create appropriately balanced incentives. For example:

(a) if two intermittent generators have forecast errors that are the same size but in opposite directions, there is no particular harm from a system perspective. However, a standards-based approach could mean the generators are in breach for their errors

(b) in some trading periods, such as when demand is low, an error will not matter much but in other trading period it could have significant consequences.

9.7. Over the next decade, the number of intermittent generators entering the New Zealand market is expected to increase considerably. While incentives and standards may incentivise new entrants to forecast accurately, they may still lack sufficient resources to produce timely and accurate forecasts. This could lead to a greater number of inaccurate forecasts, which could exacerbate the market impacts experienced today.

9.8. The effects of errors are likely to change over years as the system evolves. These factors could make it difficult to create enduring Code amendments and may mean subsequent amendments are required.

This forecasting arrangement is used in:

9.9. New Zealand (albeit without the corresponding incentives).

Further considerations:

9.10. To help ensure intermittent generators were consistently meeting accuracy standards, intermittent generators could be required to procure a service provider to provide forecasts that met the accuracy thresholds. Intermittent generators could have the ability to produce their own forecasts if they can prove to the system operator that they can demonstrate that these forecasts meet the relevant accuracy standards.

9.11. There could be benefit in the Authority periodically auditing service providers to ensure they are able to continually able to produce forecasts to the relevant standards.

Centralised forecasting

Description

9.12. A third-party forecaster would be contracted to produce forecasts for all intermittent generators.

Some advantages of this forecasting arrangement are:

9.13. It could provide a degree of accuracy that would consistently apply to all forecasts. There would also be the potential for economies of scale as the number of participants increases, depending on the funding structure. This could lead to lower costs for consumers in the long run.

Some disadvantages of this forecasting arrangement are:

9.14. If the third-party produces inaccurate forecasts, this would have a far greater systemwide impact than under a decentralised model given these forecasts would apply to all intermittent generators, and other generators (eg, thermal generators) would rely on these forecasts to determine whether to offer into market.

9.15. There would be limited ability to discover lower cost/more accurate methods over time (although there may be opportunities for competition when a contract with a centralised forecaster needs to be renewed).

This forecasting arrangement is used in:

9.16. Alberta, Ireland, Great Britain, and some Australian states. This forecasting arrangement has generally worked well in these jurisdictions. However, there have been cases where inaccurate forecasts via a centralised forecasting arrangement have resulted in undesirable outcomes. For example, in Alberta in February 2022, inaccurate wind forecasting caused pool prices to increase significantly within three hours and the supply buffer to reach 0 MW for a short time.

Further considerations:

9.17. If a centralised approach was implemented, the Authority would need to determine whether the Authority contracts for the service and/or if there is a need for Code requirements too. There is also a need to determine whether the service provider could be included as an industry participant, market operation servicer provider or other industry service provider.

9.18. It would need to be determined who would pay for a centralised arrangement. For example, the Authority or the system operator could contract the third party to produce these forecasts. Costs would be recovered from market participants via fees or levies. This is discussed later in the paper.

9.19. In the short run, a possible approach to consider is a beta-testing of the new service by contracting a service provider for a trial to assess the data, how it is used and how the market, system operator and other participants react. The Authority would welcome submitters' views on this.

9.20. Like the decentralised approach, there could be benefit in the Authority periodically auditing service providers to ensure they are able to continually able to produce forecasts to the relevant standards (if added into the Code).

Centralised with option for self-forecasting (ie, a hybrid model)

Description

9.21. A third-party forecaster would be contracted to produce forecasts for all intermittent generators. However, intermittent generators would also be able to produce their own forecasts if they can show their forecasts are accurate enough.

9.22. Intermittent generators who opt to produce their own forecasts would be required to meet an accuracy threshold. The system operator would be best placed to undertake this assessment.

Advantages and disadvantages

9.23. The advantages and disadvantages of this model are the same as those listed above (depending on whether an intermittent generator decides to use the centralised forecast or produce their own).

9.24. An additional disadvantage of this model is that there could be fewer economies of scale if some intermittent generators decide to forecast themselves, depending on the cost structure.

This forecasting arrangement is used in:

9.25. Texas and some Australian states. Like the centralised forecasting arrangement, the hybrid forecasting arrangement has generally worked well in these jurisdictions.

However, there have been cases in Texas where forecast inaccuracies have required Texas' gas generation fleet to be ramped up at short notice, which resulted in higher prices and lower operating reserves.

Compulsory ahead market and balancing market

Description

9.26. Intermittent generators would be required to submit an offer into the ahead market for their expected level of generation. Any difference between the ahead quantity and their output is settled at the balancing market price, which will reflect conditions in real-time.

9.27. For example, an intermittent generator that over forecasts its output will pay the balancing price for the shortfall generation quantity (ie, the generator's quantity cleared in the ahead market less its actual production). If the intermittent generator's shortfall occurs at a time of very tight supply, the balancing price will be high, and vice versa.

9.28. An ahead and balancing market could be implemented as part of a centralised or decentralised model.

Some advantages of this forecasting arrangement are:

9.29. It provides incentives for market participants to forecast accurately and for all generation to be sold ahead of time.

9.30. As forecasts change over time, generators would be incentivised to trade away any imbalances right up to gate closure. An accurate quantity forecast would reduce the generator's exposure to being cashed out at the balancing price.

Some disadvantages of this forecasting arrangement are:

9.31. Retrofitting a compulsory ahead market would be a significant undertaking and introduces additional complexity for market participants.

9.32. Some market participants (including intermittent generators) may be reluctant to participate in the ahead market because their output (or demand) is very uncertain. If participation is compulsory, they may seek to counter this by biasing their generation offers downward (effectively reducing their participation). This means their ahead market offer will not represent a central estimate of output. Buyers may likewise reduce their demand bids.

9.33. Ahead markets require participants (including intermittent generators) to lock-in a single estimate for their forecast level of output. Other types of forecast information may also be very useful for scheduling and dispatch purposes, such as the forecasts of P10 or P90 level of output.[42] Those other types of information will typically not be revealed via ahead market offers.

9.34. The degree of accuracy is likely to vary across generators.

9.35. Intermittent generators' private incentives may create bias in forecasts.

9.36. This option may incur high costs for small grid-connected intermittent generators, which could be perceived as a barrier to entry.

9.37. The use of a balancing market helps to prevent over forecasting because intermittent generators are required to pay the difference between the amount

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[42] A P10 (P90) wind forecast means there is a 10 percent (90 percent) chance that the amount of wind generated will be the same as or greater than the amount forecast.

forecast and the amount generated. However, it is not as effective at preventing under forecasting, as intermittent generators would get paid the balancing price for any electricity they generate above what they forecast.

This forecasting arrangement is used in:

9.38. Many EU member states, although some member states have implemented different variations of this approach (eg, Ireland uses a centralised forecasting process).

Further considerations:

9.39. Introducing an ahead market was considered as the part of the Authority's '*Driving efficient solutions to promote consumer interests through winter 2023'* project. The Authority decided not to proceed with this option as it was not possible to implement the required changes in time for winter 2023. However, the Authority's '*Driving efficient solutions to promote consumer interests through winter 2023'* Decision Paper noted that this option would be reconsidered in the future.

9.40. MDAG is also considering the merits of this option as part of its *'Price Discovery in a Renewables-Based Electricity System'* project.[43] At this stage, the Authority does not propose implementing an ahead market and balancing market as a policy solution to address inaccurate forecasting, given it would be a significant undertaking to retrofit the existing market to achieve benefits that could be achieved through a different forecasting regime.

[43] https://www.ea.govt.nz/projects/all/pricing-in-a-renewables-based-electricity-system/

Table 2: Summary of the advantages and disadvantages of forecasting arrangements

	Advantages	Disadvantages	Other considerations
Status quo: Decentralised forecasting (NZ)	• Can more readily allow local knowledge to be reflected in forecasts used for scheduling and dispatch and encourages innovation. • Does not constrain intermittent generators to one forecasting provider. • Can limit the impact of a forecasting error or bias to a single generation resource, rather than having a bias affect the forecasts for the entire system. • Can be implemented quickly and will likely have lower CAPEX and OPEX than a centralised model.	• Monitoring and enforcing incentives/standards through the Code may not be practical or provide flexibility as the effect of forecasting errors on other participants is likely to change over time. • The structure of the incentives/standards could penalise participants who, despite their best efforts with a gold standard forecast from a recognised provider, the amount of wind/solar differed from what was forecast.	• Effectiveness of decentralised forecasting depends on incentives/standards.
Centralised forecasting (Alberta, Ireland, Great Britain, default option in Australia)	• More practical to manage incentives/standards with one party compared to decentralised forecasting which involves multiple parties. • There is more flexibility to adjust forecasting requirements as the system evolves. • Possible value for money in the long run due to economies of scale.	• Forecast error has the potential to be widespread and impact a large numbers of generation resources. Can create bias in the forecasts for the entire system.	• Effectiveness of centralised forecasting depends on incentives/standards but can be addressed in the service provider's contract terms. • The Authority would only have to review accuracy of one provider and would have control over when it does this via contract.
Centralised forecasting with the option for self-forecasting (Texas, Australia)	• Enables intermittent generators to be innovative – this has the potential for higher accuracy and cost efficiencies.	• There may be less flexibility to adjust forecasting requirements for self-forecasters in the future. • There could be fewer economies of scale if some intermittent generators decide to forecast themselves.	• Intermittent generators who choose to produce their own forecasts would be required to meet an accuracy threshold. The system operator would be best placed to undertake this assessment. • The Authority would outsource to the system operator (so removed somewhat), and the system operator likely would have to review accuracy of other options on an ongoing basis.

	Advantages	Disadvantages	Other considerations
Compulsory ahead market and balancing market (EU)	• If the model is decentralised, intermittent generators would be incentivised to forecast as accurately as possible. As forecasts change over time, generators would be incentivised to trade away any imbalances right up to gate closure. An accurate quantity forecast would reduce the generator's exposure to being cashed out at the balancing price. • Intermittent generators would be incentivised to develop a greater understanding of their output and forecasts.	• Introducing an ahead market requires structural change, is complex and would take a long time to implement (could not be in place by winter 2024). • Unlikely that the costs of inaccurate forecasting alone can justify an ahead market. • Some market participants (including intermittent generators) may be reluctant to participate in the ahead market because their output (or demand) is very uncertain. If participation is compulsory, they may seek to counter this by biasing their generation offers downward (effectively reducing their participation). • May incur high costs for small grid connected intermittent generators, which could be perceived as a barrier to entry. • Not effective at preventing under forecasting situations.	• Ahead markets require participants (including intermittent generators) to lock-in a single estimate for their forecast level of output. Other types of forecast information may also be very useful for scheduling and dispatch purposes, such as the forecasts of P10 or P90 level of output. Those other types of information will typically not be revealed via ahead market offers.

Consultation questions:

Q4	What else, if anything, should be considered when assessing the relative advantages and disadvantages of the four forecasting arrangements the Authority has identified?
Q5	What other types of forecasting arrangements, if any, should be considered to improve the issue of inaccurate and unreliable forecasts?

10. Evaluation criteria

Evaluation of each option against status quo

10.1. The Authority's overarching objective is to ensure that any changes are in the long-term interests of consumers (ie, for their long-term benefit, in terms of the Authority's statutory objective).

10.2. With this factor in mind, the Authority has developed a list of evaluation criteria in Table 3. In Table 4, the Authority has undertaken a high-level assessment using the criteria to determine the extent to which:

(a) the overarching objective could be achieved under each forecasting arrangement

(b) the merits of each forecasting arrangement against the status quo

Table 3: Evaluation criteria

Criterion	Description
Effectiveness	Improves accuracy and frequency of forecasts so other participants have trust and confidence to respond to price signals
Efficiency	Mitigates risk of too much generation or demand response
Reliability	Mitigates risks to security of supply
Enhances competition	Greater trust and confidence in price signals supports competition, cost of forecasting does not act as a barrier to entry
Timely	Can be implemented prior to winter 2024
Value for money	The required benefits are balanced and considered against the costs (including implementation and compliance costs).
Futureproofed	Fit-for-purpose under a renewables-based generation system and is adaptable to changing environmental and market conditions
Uses an 'exacerbators pays' approach	The costs of inaccurate forecasts should be borne by those whose actions cause the inaccuracies
Straightforward to implement	Is simple to implement and does not require structural changes to the market
Successfulness in other jurisdictions	The forecasting arrangement has led to more accurate forecasts by intermittent generators in other jurisdictions

Consultation question:

Q6	Do you agree with the proposed evaluation criteria? If not, what is your view and why? Are there other criteria that the Authority should consider?

Table 4: Assessment of each option against evaluation criteria

Evaluation criteria → / Options ↓	Effectiveness	Efficiency	Reliability	Enhances competition	Timely	Value for money	Future-proofed	Uses an 'exacerbators pays' approach	Straight-forward to implement	Successful-ness in other jurisdictions	**Overall assessment**
Status quo	Low (1)	Medium (2)	Low (1)	Medium (2)	High (3)	Medium (2)	Low (1)	Low (1)	High (3)	N/A	**16**
1) Decentralised model with incentives/ standards	Medium (2)	Medium (2)	Medium (2)	Medium (2)	High (3)	Medium (2)	Medium (2)	Medium (2)	High (3)	N/A	**20**
2) Centralised model	High (3)	High (3)	High (3)	Medium (2)	Medium (2)	High (3)	Medium (2)	Medium (2)	Medium (2)	Medium (2)	**24**
3) Centralised model with option for self-forecasting	High (3)	Medium (2)	High (3)	High (3)	Medium (2)	High (3)	High (3)	Medium (2)	Medium (2)	Medium (2)	**25**
4) Ahead and balancing market	Medium (2)	Medium (2)	High (3)	Medium (2)	Low (1)	Low (1)	Medium (2)	High (3)	Low (1)	Medium (2)	**19**

10.3. Based on the high-level evaluation above, all four options would be an improvement on the status quo. This evaluation is supported by the fact that other jurisdictions that have adopted other forms of forecasting arrangements for intermittent generators are generally performing better than New Zealand in terms of forecast accuracy and minimising subsequent impacts on other market participants and the electricity system.

10.4. A centralised forecasting arrangement and a centralised arrangement with the option for self-forecasting both scored the highest when considering all proposed evaluation criteria, followed by a decentralised arrangement with incentives/standards. The ahead and balancing market option scored the lowest, primarily because it would take a long time to implement and would be costly and complex.

10.5. Based on the evaluation above and the considerations in the previous section, the Authority's preliminary view is that the implementation of a centralised forecasting arrangement (or a centralised arrangement with the option for self-forecasting) will be the most beneficial. Compared to a decentralised arrangement with incentives/standards, a centralised arrangement is likely to result in more accurate and reliable forecasts, is better value for money, and enables the ability for forecasting requirements to be adjusted as the system evolves. It has also been shown to be a relatively successful type of arrangement in Alberta, Australia, and Texas.

10.6. The Authority does not consider that the implementation of an ahead and balancing market can be justified at this time. The need to retrofit the existing market would be a significant and complex undertaking that would take several years to complete, meaning improvements in forecast accuracy may not eventuate during a period when the number of intermittent generators entering the market is increasing and the proportion of intermittent generation sources continues to grow. The Authority is also concerned that an ahead and balancing market option may incur high costs for small grid-connected intermittent generators, which could be perceived as a barrier to entry during a time when there is a need to increase intermittent generation capacity.

10.7. The Authority did not weight the evaluation criteria, but some criteria could be considered more important than others. The Authority would welcome feedback from submitters on whether certain criteria should be given a greater weighting.

Consultation questions:

Q7	Do you agree with the Authority's assessment of each forecasting arrangement above? If not, why not?
Q8	The Authority has not weighted the criteria based on importance. Are there particular criteria that you consider to be more important that the others?
Q9	Are there additional criteria that the Authority should be considering?

11. Principles and design considerations

Principles underpinning any policy solution

11.1. The Authority considers the following principles should underpin any policy solution:

(a) individual generators should be responsible for incorporating forecasts into offers (the quantity of generation and what it is priced at)

(b) individual generators should be responsible for offers

(c) generators should be responsible for revenues earnt in the spot market.

(d) the policy decision aligns with a forecasting arrangement in one of the international jurisdictions that has been assessed

(e) the policy solution does not require integration with the system operator's systems – this will save time and money.

11.2. These principles all support the Authority's main statutory objective – to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers.

Design considerations

11.3. In this section, the Authority has assessed each forecasting arrangement against certain design considerations to help determine how each option would be implemented. The Authority considers the following design considerations to be relevant:

Frequency of forecasts

- How far ahead of real time is there a need for forecasts?
- How often should forecasts be made?

Accuracy standards, incentives and penalties

- Should there be a minimum level of accuracy?

Paying for and submitting forecasts

- Who would have responsibility for submitting forecasts?
- Who would pay for forecasting?

Publication of information

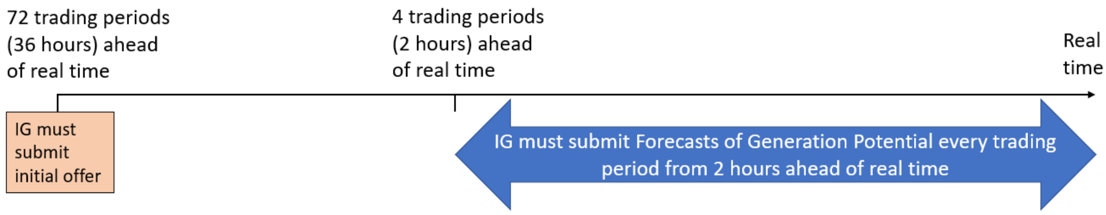
- What information should be published?

12. Frequency and accuracy of forecasts: How far ahead of real time is there a need for more accurate forecasts and how often should forecasts be made?

12.1. Within two hours of a trading period, intermittent generators are currently required to submit FOGPs based on a resource persistence model (unless otherwise agreed with the Authority) for each trading period.[44]

12.2. There are currently no requirements or incentives in the Code around the frequency and accuracy of intermittent generation forecasts more than two hours ahead of a trading period.

Figure 2: Status quo



12.3. Given the intermittent nature of wind and solar energy, there will always be a degree of uncertainty when forecasting how much electricity can be generated from these sources. Perfect accuracy is not possible. A more realistic goal is to minimise inaccuracy and for forecasts to be accurate enough to give participants trust and confidence in forecasts.

12.4. The Authority's goal is to ensure that any increase in the frequency and accuracy of forecasts is useful for participants, particularly those whose generation or consumption decisions are based on these forecasts. For example, more frequent forecasting may be useful as it can indicate the direction of forecasts (ie, is wind speed increasing, decreasing, or remaining constant leading up to real time).

12.5. The Authority has met with several weather forecasting providers to discuss their ability to forecast wind and solar frequently and accurately, and what the limitations are. Providers that the Authority has spoken to have advised that they use several models to forecast wind and solar. Some models are more accurate than others, and models are often overlayed or combined to assess different scenarios.

12.6. The Authority has also been advised that wind and solar forecasts are generally quite accurate about six hours ahead of real time. Forecasts become increasingly uncertain from six hours out.

12.7. Some forecasting models are updated every 12 hours, some are updated every six hours, and some are updated every hour. Models could theoretically be updated even more frequently (eg, every half an hour to align with trading period timeframes), but this would be associated with increased costs for the forecasting provider.

[44] Refer to clause 13.18A of the Code.

12.8. If there was a requirement to increase forecast frequency, it would seem practical for intermittent generators to also be required to revise their offers to reflect the most recent forecast.

Consideration of thermal generators' needs

12.9. To help determine the impact that under forecasting has on thermal generators' decisions whether to run, the Authority has looked into how frequently slow-start thermal units start up but are not dispatched.

12.10. Due to the high start-up and running costs, generally operators of slow-start thermal units will only offer into the market if the price signals indicate it make economic sense to do so. This will typically be during periods of expected high demand and/or low intermittent supply, which put upwards pressure on prices.

12.11. Thermal generators will also consider how recently a slow-start thermal unit has been used when deciding what price to offer it into the market. Based on information the Authority has received from Genesis Energy, it can take a Rankine unit up to 8 hours 30 minutes from it syncing to operating at 50 MW output and 10 hours to maximum output.

12.12. This information is useful to help determine potential frequency requirements or accuracy standards for intermittent generators.

Consideration of demand-side participants' needs

12.13. Demand-side participants, like thermal generators, need advance notice to assist with their decision making. For example, a large industrial user may need several hours to curtail demand, or a battery owner may need time to charge the battery before it is discharged to the grid.

Consultation question:

Q10	How frequently do you think intermittent generation forecasts should be updated, and how often do you think intermittent generators should be required to revise their offers to reflect updated forecasts?

13. Accuracy standards and incentives: Should there be minimum level of accuracy requirements in the Code or a service provider's contract?

13.1. Currently, intermittent generators must submit a report to the Authority if an individual plant generates 30 MW or below the FOGP in their final offer.[45] The Authority receives a high number of reports each month.

13.2. The high number of breaches suggests the current requirement of submitting a report may not be a sufficient incentive for intermittent generators to protect against large shortfalls in generation close to dispatch. This requirement also only addresses situations where over forecasting occurs. The Authority considers it necessary to also address situations where under forecasting occurs.

13.3. To better incentivise intermittent generators to comply with any accuracy and frequency requirements, the Authority is considering introducing forecasting

[45] Refer to clause 13.86A(2) of the Code.

standards. Where there is a breach of those standards the breach would be investigated, and the usual compliance process followed. If the breach went to the Rulings Panel it could make a remedial order which may include penalties.

13.4. Before considering what standards or incentives may be appropriate, the following caveats need to be understood:

(a) Perfect accuracy is not possible – in most cases there will always be a degree of inaccuracy and uncertainty associated with forecasts.

(b) Given perfect accuracy is not possible, a desired level of accuracy needs to be decided upon. The definition of 'desirable' is likely to vary according to system conditions. For example, in some trading periods an error will not matter much but in others it could have very significant consequences. More generally, the effects of errors are likely to change over years as the system evolves. These factors make it difficult to specify enduring requirements for forecasting.

(c) From a system perspective, what really matters is the accuracy of overall forecasts. If two intermittent generators have forecast errors that are the same size but in opposite directions, there is no particular harm from a system perspective. However, a standards-based approach could end up penalising both generators for their errors.

Standards

Purpose

13.5. Standards help to ensure a minimum level of accuracy.

Types of standards

13.6. There are two main types of standards – outcome standards and process standards.

13.7. Outcome standards may allow more flexibility over time than process standards – intermittent generators/centralised forecasters are free to discover ways to achieve standards.

13.8. Process standards may provide more certainty over accuracy without unduly penalising intermittent generators as intermittent generation is largely driven by the weather, which is inherently unpredictable. An example of a process standard is specifying a forecasting method that must be used.

13.9. It is difficult to enforce standards/incentives in the Code as weather forecasts have a degree of unpredictability.

13.10. The Commerce Commission uses a series of measures to report the average frequency and duration of sustained outages (eg, System Average Interruption Duration Index, System Average Interruption Frequency Index, and Customer Average Interruption Duration Index). These measures could be considered when developing measures for intermittent generation forecasts.

What other jurisdictions do

13.11. There is a mix of outcome and process type standards used in other jurisdictions.

Applicability to decentralised and centralised models in New Zealand

13.12. Under a centralised model, it may be easier to implement outcome and process standards for a single third-party forecaster (as opposed to individual intermittent generators under a decentralised model).

13.13. Under a decentralised model, standards may be more appropriate to ensure consumers are protected against inaccurate forecasting and may provide better value for money than financial incentives through a service provider's contract under a centralised model.

13.14. When considering accuracy standards, it is beneficial to also consider the link with forecast frequency. For example, rather than having a single accuracy standard that applies a certain period before the relevant trading period, multiple standards could apply that increase closer to real time. An example is illustrated below.

13.15. The Authority would welcome views from submitters on whether an accuracy standard should be focused on ensuring actual generation is within 30 MW of the amount that was forecast (ie, consistent with the current 30 MW threshold), or whether the MW compliance threshold should be higher or lower.

13.16. When considering whether the MW compliance threshold should be higher or lower, it is worth noting that generators that are not intermittent generators must immediately submit a revised offer to the system operator if 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.

13.17. It is also worth considering whether a compliance threshold should be based on the percentage of installed capacity rather than a certain amount of MW.

13.18. The Authority would also welcome views on whether there should be different standards as you get closer to real time. For example, at T-12 hours, a P50 forecast should be +/- 30 MW from actual generation at real time, and at T-3 hours this could be narrowed to +/- 10 MW.

Consultation questions:

Q11	Do you think the Authority should implement accuracy standards? If not, please explain why.
Q12	If the Authority was to implement accuracy standards: a) do you think outcome process standards would be more effective? b) should there be a single standard or multiple standards across different timeframes? c) should the standard(s) be focused on ensuring actual generation is within 30 MW of the amount that was forecast, or should the MW threshold be higher or lower? d) should the accuracy standards be based on the percentage of installed capacity rather than a certain amount of MW?
Q13	Following the 9 August 2021 grid emergency, reports from two investigations recommended that the Authority amend the Code to disallow persistence forecasting

	and require wind generations make more accurate offers to the system operator about supply. Do you agree that the Authority should amend the Code to disallow persistence forecasting?

Incentives and penalties

Purpose

13.19. Incentives and penalties can help intermittent generators achieve continuous improvement above and beyond a minimum standard.

Types of incentives

13.20. Financial incentives under contracts and penalties under contracts (for breach of obligations in a contract) are the most common. Incentives can be explicit (eg, financial rewards for accuracy contained in a contract) or implicit (eg, loss of contract when the term is complete). There also needs to be incentives on generators to ensure they provide accurate plant information to the service provider (such as planned outage schedules).

What other jurisdictions do

13.21. Incentives and penalties in other jurisdictions are mostly financial.

13.22. In jurisdictions that have a centralised arrangement, incentives are typically focused on the service provider(s) that compile the forecasts and are generally applied via service provider contracts.

Texas (Electric Reliability Council of Texas)

13.23. In Texas, the forecasting service providers are incentivised to forecast accurately due the contracts negotiated with the Electric Reliability Council of Texas, which have performance-based payment structures.

13.24. Generators that do their own forecasting have a more limited incentive to be accurate, as self-forecasts can only cause the High Sustained Limit[46] (and therefore the dispatch base point) to be reduced. If a generator self-forecasts a higher output, that cannot be used in the dispatch process. If the incorrectly self-forecast a lower output, the main consequence will just be that they are dispatched a lower quantity, so they may have to reduce output to avoid a base point deviation charge (although this only applies if generation is capped).

Australia (National Energy Market)

13.25. In the National Energy Market, frequency keeping costs are allocated on a causer-pays basis – ie, if the system is running below target frequency, intermittent generators that are generating less than forecast (and are thus contributing to system underfrequency) will be allocated more of these costs, and vice versa.

13.26. If a generator can successfully predict that the system will be running below frequency, they will be incentivised to forecast conservatively so that they end up

[46] For intermittent generation, the High Sustained Limit is the current net output capacity of the generation resource based on current weather and plant conditions (ie, wind/irradiance and turbines/inverters online). Unlike the nameplate capacity of the generation resource, the HSL will vary over time.

generating above this forecast. They would then be deemed to be making a positive contribution to system frequency, so their allocation of costs would be decreased.

13.27. The reverse is also true – if system over-frequency is expected, a generator will be incentivised to forecast ambitiously so that they actually generate below this forecast and contribute to keeping frequency down. The Australian Energy Market Commission is currently working on making sure that the incentives to self-forecasting generally are correctly calibrated.

EU member states

13.28. In some EU member states that have an ahead and balancing market arrangement, a penalty is applied to the balancing market price (a discount for cashing out positive imbalances, and a premium for cashing out negative imbalances) to incentivise participants to use the ahead market and minimise their balancing market exposure. However, such penalties can create an unintended bias in ahead market offer quantities, especially if they are not symmetrical.

Alberta (Alberta Electric System Operator)

13.29. As part of its review, Concept was unable to locate any specific information on the terms of the service provider contracts for the provision intermittent generation quantity forecasts. To the extent that incentives apply in relation to accuracy of forecasts, it can be assumed these would be included in the service provider contracts.

Applicability to decentralised and centralised models in New Zealand

13.30. In New Zealand, the penalties for Code breaches are specified in the Electricity Industry Act 2010[47] and are determined by the Rulings Panel. Therefore, while the Authority could introduce a new standard, it cannot introduce new penalties in the Code.

13.31. If a centralised forecasting arrangement was implemented, incentives or penalty provisions could be included in a service provider's contract (and would be subject to negotiation). There could also be an opportunity to renew incentives and penalty provisions through the contract.

Other considerations

13.32. It is important to avoid any bias in incentives for the forecaster (or party engaging the forecaster). Such a bias could lead to reliability problems or undue costs for consumers. For example, a downward bias in forecasting intermittent generation output could lead to over-procurement of other resources and additional constrained-on costs.

13.33. To minimise the scope for unintended bias, the forecasting objective (eg, P50) should be clearly specified with regular reporting to measure performance. It is worth noting that system operators often have a mandate and an operational ethos that focuses on reliability.

13.34. Reliability failures are also more high-profile than cost inefficiencies. As such, forecasts prepared or procured by a system operator may be biased towards

[47] The maximum penalty is $2 million or $10,000/day if the breach is continuing.

under-forecasting intermittent generation in order to prioritise system reliability over cost efficiency. On the other hand, electricity regulators tend to have a more balanced mandate that includes cost efficiency as well as reliability, so forecasts prepared or procured by regulators may not have such biases.

13.35. Currently, intermittent generators are required to submit a report to the Authority if an individual plant generates 30 MW or below the FOGP in their final offer, but they do not have to do anything if they generate more than the FOGP. However, an intermittent generator has little control over its ability to generate enough (ie, wind/solar may not eventuate), but it has full control over its ability to not generate too much (ie, it could limit generation). Therefore, under a centralised forecasting arrangement, it could be practical for penalties to be stronger for over generating/under forecasting.

Consultation questions:

Q14	Do you think the Authority should implement accuracy requirements? If not, please explain why.
Q15	If the Authority was to implement a decentralised forecasting arrangement, do you have any suggestions for what type of incentives could beconsidered ?
Q16	If the Authority was to implement a centralised forecasting arrangement: a) do you have any suggestions for what type of incentives could be applied? b) should penalties for not meeting the standard(s) be prescribed? c) should penalties be higher for over generating than under generating (or vice versa)?

14. Paying for and submitting forecasts: Who would have responsibility for submitting forecasts and who would pay for forecasting?

14.1. Table 5 includes a summary of the responsibilities for submitting and paying for forecasts under each forecasting arrangement.

Table 5: Summary of the responsibilities for submitting and paying for forecasts under each forecasting arrangement

Option	Responsibility for submitting forecasts	Who pays for forecasting	Considerations
Decentralised model with accuracy requirements (without structural changes)	Intermittent generators would continue to be responsible for submitting their own forecasts to the system operator.	Intermittent generators would continue to be responsible for paying for their own forecasts.	This model would put a greater onus on intermittent generators to forecast accurately. This would incur greater costs for intermittent generators.
Centralised model	The Authority or the system operator would receive forecasts from a third-party provider. The system operator would then be responsible for submitting forecasts.	The Authority or the system operator could contract the third party to produce these forecasts. Costs would be recovered from market participants via fees or levies.	This model would incur significantly higher costs for the Authority and/or the system operator compared to the status quo. If the system operator did not have to install the centralised wind model into its operating system (ie, the centralised forecasts were provided directly to intermittent generators), it would reduce the CAPEX incurred by the system operator.
Centralised model with option for self-forecasting	Same as above, but intermittent generators could submit their own forecasts if they can prove to the system operator they can meet an accuracy threshold.	Same as above, but intermittent generators could pay for and produce their own forecasts if they can prove to the system operator they can meet an accuracy threshold.	This option could incur higher costs for the system operator (who would still need to produce its own centralised forecasts). If the central forecast is based on a “per party subscription”, it may be cheaper for the system operator if a greater number of intermittent generators opt out and produce their own forecasts. As above, if the system operator did not have to install the centralised wind model into its operating system, it would reduce the CAPEX incurred by the system operator.
Ahead and balancing market	Depends on whether it would be done as part of a centralised or decentralised model.		

Consultation question:

Q17	Do you have a view on who should have responsibility for submitting forecasts and who should pay for forecasting?

15. Publication of information

15.1. The publication of certain information could assist the system operator with its scheduling and dispatch decisions, and market participants with their generation or consumption decisions. For example, publishing confidence intervals can help indicate the degree of uncertainty in forecasts of intermittent generation.

15.2. The types of information that is published and who should be responsible for publishing certain information would depend on which forecasting arrangement is implemented. For example, under a decentralised approach, intermittent generations could be responsible for publishing certain information. Under a centralised model, this responsibility could sit with the centralised forecasters (albeit with extensive data inputs provided by intermittent generators).

15.3. It would be practical for information to be published on a platform that is accessible by all market participants, similar to the Wholesale Information System Trading dashboard hosted by NZX.

15.4. The Authority welcomes feedback on what types of information should be published and what platform it should be published on.

Consultation question:

Q18	Do you have a view on what types of information should be published and what platform it should be published on?

16. Next steps

16.1. The Authority welcomes responses from interested parties on the consultation questions outlined in this paper.

16.2. If a decision is made to proceed with:

(a) a decentralised forecasting arrangement with incentives/standards (option one), the Authority will publish a consultation paper on proposed Code changes

(b) a centralised forecasting arrangement (option two) or hybrid approach (option three), the Authority will publish a Request for Information to determine which parties could potentially offer a centralised forecasting service, followed by a Registration of Interest and Request for Proposal.

16.3. At this stage, the Authority does not propose implementing an ahead market and balancing market (option four), given it would be a significant undertaking to retrofit the existing market to achieve benefits that could be achieved through a different forecasting regime. However, the Authority welcomes submitters' views on this.

16.4. The Authority will keep interested parties updated via its Market Brief.

16.5. The Authority's preference, at this stage (subject to submissions), is to implement a policy solution by winter 2024. Before the implementation of any option, the Authority will publish a decision paper outlining the option the Authority has decided to implement and the reasons why.

17. Attachments

17.1. The following appendices are attached to this paper:

Appendix A Concept Consulting Report: *Intermittent generation forecasting arrangements – review of international jurisdictions*

Appendix B Ernst & Young Report: *Impacts of wind forecasting accuracy on the wholesale electricity market and broader electricity system*

Appendix C Format for submissions

Appendix A Concept Consulting Report: Intermittent generation forecasting arrangements – review of international jurisdictions

Appendix B Ernst & Young Report: Impacts of wind forecasting accuracy on the wholesale electricity market and broader electricity system

Appendix C Format for submissions

Submitter	

Question #	Question	Comment
Q1	Do you agree with the Authority's problem definition? If not, why not?	
Q2	Do you agree that a new forecasting arrangement should apply to all grid-connected intermittent generators that are required to submit offers?	
Q3	Note this question is referring specifically to generators who have thermal assets: For all trading periods between 1 November 2019 and 31 October 2022, how often do you think you made the incorrect decision whether to start or stop your thermal unit(s)? Please provide reasons why this occurred.	
Q4	What else, if anything, should be considered when assessing the relative advantages and disadvantages of the four forecasting arrangements the Authority has identified?	
Q5	What other types of forecasting arrangements, if any, should be considered to improve the issue of inaccurate and unreliable forecasts?	
Q6	Do you agree with the proposed evaluation criteria? If not, what is your view and why? Are there other criteria that the Authority should consider?	
Q7	Do you agree with the Authority's assessment of each forecasting arrangement above? If not, why not?	

Q8	The Authority has not weighted the criteria based on importance. Are there particular criteria that you consider to be more important that the others?	
Q9	Are there additional criteria that the Authority should be considering?	
Q10	How frequently do you think intermittent generation forecasts should be updated, and how often do you think intermittent generators should be required to revise their offers to reflect updated forecasts?	
Q11	Do you think the Authority should implement accuracy standards? If not, please explain why.	
Q12	If the Authority was to implement accuracy standards: do you think outcome process standards would be more effective? should there be a single standard or multiple standards across different timeframes? should the standard(s) be focused on ensuring actual generation is within 30 MW of the amount that was forecast, or should the MW compliance threshold be higher or lower? should the accuracy standards be based on the percentage of installed capacity rather than a certain amount of MW?	
Q13	Following the 9 August 2021 grid emergency, reports from two investigations recommended that the Authority amend the Code to disallow persistence forecasting and require wind generations make more accurate offers to the system operator about supply. Do you agree that the Authority should amend the Code to disallow persistence forecasting?	
Q14	Do you think the Authority should implement accuracy incentives and/or penalties for non-compliance? If not, please explain why.	

Q15	If the Authority was to implement a decentralised forecasting arrangement, do you have any suggestions for what type of incentives could be applied?	
Q16	If the Authority was to implement a centralised forecasting arrangement: a) do you have any suggestions for what type of incentives could be applied? b) should penalties for not meeting the standard(s) be prescribed? c) should penalties be higher for over generating than under generating (or vice versa)?	
Q17	Do you have a view on who should have responsibility for submitting forecasts and who should pay for forecasting?	
Q18	Do you have a view on what types of information should be published and what platform it should be published on?	