Analysis of Wind Power Forecasts

21 February 2025

Executive summary

In the past few years more intermittent generation, such as wind and solar, has entered the New Zealand market and more is expected in the future. However, the Electricity Authority Te Mana Hiko (Authority) has found that forecasts of intermittent generation are often inaccurate by a large margin, which risks increasing costs for consumers. For this reason, the Authority is putting in place a hybrid forecasting arrangement and implementing forecast performance standards, which will promote more consistently accurate intermittent generation forecasts.[1]

This paper presents a performance analysis of the current wind forecasts for various wind farms across several forecasting horizons (2, 4, 12 and 36 hours ahead). We refer to those wind farms by their operators (not necessarily the same as their owners – see explanatory note below). Forecast performance was assessed using different metrics to provide a sense of wind generators' accuracy and bias (towards either under or over-forecasting). This analysis will serve as a guide for the forecast performance standards that will apply under the hybrid forecasting arrangement.

Our results show that the forecasts are reasonably unbiased for most wind farms. However, a slight tendency to over-forecast was found. The bias in the forecast tends to increase during windier months (spring and summer).

Due to their size, on average, the forecasts for smaller wind farms (less than 50MW capacity) are more accurate in MW terms.[2] This means the current 30MW 'threshold' that applies to intermittent generators[3] is easier to achieve for smaller wind farms. For this reason, we also assessed forecast performance relative to the plant's available capacity and relative to the last submitted forecast of generation potential (FOGP).[4]

In this paper, we established the following forecast performance thresholds:

a) over-forecast error equal to or less than 30MW
b) over-forecast error equal to or less than 20% of available capacity[5]
c) over-forecast error equal to or less than 20% of FOGP or 10MW (whichever is greater).

Mercury's Turitea wind farm showed the best results in terms of the percentage of available capacity, crossing the 20% over-forecast threshold only 2.2% of the time for the 2-hour ahead case, followed by Mercury's Kaiwera Downs wind farm (5.8% of the time). Most wind farms (8 out of 13) crossed the 20% over-forecast threshold less than 10% of the time. Only Waipipi (Genesis-operated), Tararua (stages 1-3; Manawa-operated), and Te Āpiti (Meridian) wind farms were above the 20% threshold more than 10% of the time for the 2-hour ahead forecasts.

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[1] Electricity Authority - (Decision paper) Review of forecasting provisions for intermittent generators in the spot market (2024)

[2] For 2-hour ahead forecasts, the five smaller wind farms (less than 50MW capacity) had average inaccuracy of ~24MW, while the five largest wind farms had average inaccuracy of ~58MW.

[3] Currently, under clause 13.86A(2) of the Code, an 'intermittent generator must not generate electricity during a trading period at a rate that is more than 30MW below the forecast of generation potential specified in the intermittent generator's final offer'.

[4] A FOGP is an intermittent generator's estimate of electricity (specified in MW) it will generate during a trading period and forms part of an intermittent generator's offer.

[5] Available capacity means the plant nominal capacity minus outages (if any).

Manawa-operated Mahinerangi wind farm performed best relative to the FOGP threshold (ie, forecast inaccuracy as a percentage of FOGP), crossing the 20% threshold 3.9% of the time, closely followed by Mercury's Kaiwera Downs wind farm (4.4% of the time). The only other wind farms crossing the 20% threshold less than 10% of the time for the 2-hour ahead case were NZ Windfarms' Te Rere Hau wind farm and Meridian's White Hill wind farm.

Finally, we developed six scenarios to understand the impact that standards based on the percentage of available capacity or FOGP would have on electricity market prices (assuming the thresholds were never crossed). The results showed that if the current 30MW 'threshold' was never crossed, it would lead to a reduction in the average spot price by around 7% compared to if no standard applied. However, if this threshold was replaced by a standard based on the percentage of available capacity or FOGP, it would lead to a greater reduction in the average spot price (between around 10% and 16%). Additionally, we found that the price impact could be even more significant during periods of low generation residuals (tight supply).

Most wind farms in New Zealand are smaller than 100MW but combined these smaller farms account for more than 700MW of capacity. It is important, therefore, to have forecast performance standards in place that incentivise better forecast accuracy for small and large wind farms. This will become more important as increased intermittent generation enters the market and becomes more geographically spread. The two proposed thresholds (inaccuracies relative to the available capacity or FOGP) could be used to address this issue.

Explanatory note:

Mercury outsources the operation of some of its wind farms to third parties via power purchase agreements. These parties are responsible for arranging forecasts for that wind farm and submitting generation offers.

Currently, five Mercury-owned wind farms in New Zealand are operated by a third party. These are:

- Waipipi – operated by Genesis
- Tararua 1, 2 and 3 – operated by Manawa
- Mahinerangi (Waipori B) – operated by Manawa

In this paper, we refer to the party that operates the wind farm.

Explanatory note:

The hybrid forecasting arrangement will apply to most wind and solar generators. However, this analysis focused solely on wind generation for the following reasons:

a) the amount of wind generation installed in New Zealand is considerably greater than solar generation
b) there is limited data on the accuracy of solar forecasts, as large-scale solar farms have only been established in New Zealand recently.

This analysis included 13 wind farms in New Zealand, as they are large enough to be required to submit generation offers. One wind farm, Harapaki, was excluded due to the limited amount of available data, as it was fully commissioned only in mid-2024. Smaller wind farms with capacity less than 10MW were also excluded from this analysis.

Contents

1. The Authority has decided to implement a hybrid forecasting arrangement for intermittent generation

1.1. In the past few years more intermittent generation has entered the market and the penetration of wind and solar continues to increase. However, the Authority has found that forecasts of intermittent generation are often inaccurate and unreliable, even close to real-time, which causes problems for the power system and risks increasing costs for consumers.

1.2. To address these issues, the Authority conducted a review of forecasting provisions for intermittent generators. In July 2024, we published a Decision Paper outlining the key outcomes of this review.[6]

1.3. The Authority's primary decisions include implementing a hybrid forecasting arrangement and amending the Code to support this new approach. Under the hybrid arrangement, a centrally procured forecast will be provided for each intermittent generation site. Intermittent generators may also submit offers using their own forecasts if they can demonstrate to the Authority that their forecasts meet the forecast performance standards that the centralised forecast must meet.

1.4. These changes aim to improve the accuracy of intermittent generators' offers across all trading periods, increasing confidence in the availability of their generation. This will enhance the reliability, efficiency and affordability of the electricity system. Additionally, the hybrid arrangement is expected to foster competition and innovation by reducing entry barriers for new developers of intermittent generation.

2. This analysis supports the policy work on developing an accuracy threshold for intermittent generation

2.1. The purpose of this paper is to:

(a) analyse the accuracy and bias of intermittent generation forecasts submitted between 2021 and 2024

(b) propose potential forecast performance standards that would apply to the centralised forecaster under the hybrid forecasting arrangement[7]

(c) estimate the price impact that those standards can have on the market.

2.2. This paper also supports the materials the Authority has published so far on this topic, including:

- the July 2024 Decision Paper that presented the key decisions from our review of forecasting provisions for intermittent generators, including the

[6] See: Electricity Authority - (Decision paper) Review of forecasting provisions for intermittent generators in the spot market (2024)

[7] Intermittent generators that want to use their own forecast must also show that their forecasts meet these standards.

decision to implement a hybrid forecasting arrangement and to introduce forecast performance standards[8]

- the October 2024 Consultation Paper on the proposed changes to the Code to give effect to the hybrid forecasting arrangement decisions[9]
- the February 2025 Decision Paper confirming the final amendments the Authority will make to the Code to give effect to the hybrid forecasting arrangement[10]
- a dashboard illustrating forecast accuracy for each wind generator and wind generation site across different timeframes (on a monthly scale)[11]
- an article to illustrate the performance of the forecasts of individual wind farms and to educate readers about the importance of more accurate intermittent generation forecasting.[12]

2.3. In this paper, we focus on wind power forecasting due to its current larger penetration into the grid and a longer set of historical data compared to solar. However, we do not exclude the possibility of conducting a similar analysis on solar power forecasting when more data is available. We have defined forecast error (inaccuracy) as actual generation minus forecast generation.

2.4. The study was conducted in two parts, the first looking at the accuracy and performance of wind forecasts, and the second designing 'what-if' scenarios intended to examine the impact of selected wind forecasting standards on the electricity wholesale spot prices. The first part of the study uses data from 1January 2021 to 31 October 2024, while the modelled scenarios include data from 1 November 2022 to 10 October 2023.[13]

2.5. We did not include Meridian's Harapaki wind farm in the analysis due to the relatively small amount of available data since it was fully commissioned in July 2024.[14]

Our approach focuses on over-forecast events but the goal is to have unbiased forecasts

2.6. Wind power forecast inaccuracies can pose challenges to the market. When the forecast is lower than the actual generation (under-forecast) this could signal to the market that more generation is needed, potentially leading to unrecovered costs to

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[8] See footnote 5.

[9] See: Electricity Authority - (Consultation paper) Review of forecasting provisions for intermittent generators – proposed Code amendments (2024)

[10] Electricity Authority-(Decision paper) Review of forecasting provisions for intermittent generators – final Code amendments

[11] See: https://public.tableau.com/app/profile/electricity.authority/viz/Intermittentgenerationforecasting/Intermittentgeneratorforecasting

[12] See: Changes to wind and solar forecasting set to improve electricity system reliability | Electricity Authority

[13] To simplify the analysis, we have used data from when Real Time Pricing (RTP) began, which is 1 November 2022.

[14] See: Transpower – Customer Advice Notice (Revision): Harapaki Wind Farm classified as a secondary risk while commissioning

slow start thermal operators if their units get dispatched and prices turn out to be lower than forecast.

2.7. On the other hand, when the forecast wind is above what ends up being generated (over-forecast), the expected surplus of wind might lead slow-start thermal plants to not start (if they were not already running), which can require more expensive peaking plants to be dispatched to cover demand and can lead to insufficient generation in more extreme cases (ie, a tight-supply event).

2.8. Due to their potential impact on security of supply, most of our discussion is focused on over-forecast events. However, since under-forecast events can impact other market participants, which can ultimately disadvantage consumers, intermittent forecast providers should always aim to have accurate and unbiased forecasts.[15]

3. Wind forecast accuracy varies considerably between wind farms

3.1. In this section we assess wind power forecasting accuracy for different wind farms against three well-known and widely used metrics:

(a) Mean absolute error (MAE),

(b) Root mean squared error (RMSE),

(c) Mean bias error (MBE).

3.2. The MAE and RMSE provide a sense of the average magnitude of the inaccuracies; RMSE is useful when large errors are particularly undesirable, which is the case for wind power forecasts, since large errors can have a large impact on market performance, as discussed in the previous section. MAE does not weight large and small errors differently and provides the absolute deviation of the predicted values. The MBE informs whether the forecast tends to under or over-forecast wind power.[16]

3.3. Table 1 shows the results for 2- and 12-hour ahead forecasts. The results indicate that wind farms with less than 50MW capacity have smaller inaccuracies in MW terms than larger ones, especially for the 2-hour ahead case. For instance, wind farms such as Genesis-operated Waipipi (133MW), Manawa-operated Tararua stage 3 (93MW), and Meridian's Te Āpiti (90MW), all had MAE and RMSE above 10MW for the 2-hour ahead forecasts while smaller plants such as Manawa-operated Tararua stages 1 and 2 (36MW and 37MW respectively) and Mercury's Kaiwera Downs (43MW) were below 10MW.

3.4. Among the wind farms with less than 50MW capacity, NZ Windfarms' Te Rere Hau showed the smallest 2-hour ahead inaccuracies (MAE of 4.43MW and RMSE of 6.87MW) followed by Mercury's Kaiwera Downs. Manawa-operated Tararua stage 2

[15] This is discussed more in Hanifi, Shahram, Xiaolei Liu, Zi Lin, and Saeid Lotfian. 2020. "A Critical Review of Wind Power Forecasting Methods—Past, Present and Future" *Energies* 13, no. 15: 3764.

[16] This is discussed in Piotrowski, Paweł, Inajara Rutyna, Dariusz Baczyński, and Marcin Kopyt. 2022. "Evaluation Metrics for Wind Power Forecasts: A Comprehensive Review and Statistical Analysis of Errors" *Energies* 15, no. 24: 9657. https://doi.org/10.3390/en15249657 and in Sengupta, M., Habte, A., Wilbert, S., Gueymard, C., & Remund, J. (2021). *Best practices handbook for the collection and use of solar resource data for solar energy applications* (No. NREL/TP-5D00-77635). National Renewable Energy Lab.(NREL), Golden, CO (United States).

showed the worst results among the smaller farms (MAE of 5.69MW; RMSE of 7.88MW).

3.5. However, Te Rere Hau showed much more variation in accuracy between 2 and 12-hour ahead forecasts than the other small farms. For instance, while the MAE for the 12-hour ahead forecasts for Mahinerangi, Tararua stage 1, Tararua stage 2, and Kaiwera Downs was between ~5.1 and ~5.9MW, Te Rere Hau's MAE was ~9.7MW. Similar trends can be seen for the RMSE.

3.6. The largest wind farm, Mercury's Turitea (222MW capacity), showed smaller inaccuracies compared to the second largest wind farm, the Genesis-operated Waipipi wind farm (133MW).[17] Turitea's MAE and RMSE were 12.91MW and 19.40MW for the 2-hour ahead forecasts, while Waipipi had MAE and RMSE above 15MW and 25MW respectively for the same forecast horizon. Manawa-operated Turitea stage 3 (93MW) and Meridian's Te Āpiti (90MW), showed comparable results, with Te Āpiti being slightly more accurate, especially for the 2-hour ahead forecast.

3.7. The MBE results show that the wind farms tend to have small wind forecast bias, especially for the 2-hour ahead forecast horizon (MBE close to 0MW). However, most wind farms showed an over-forecast tendency, as shown by the number of negative MBE values in Table 1 (9 out of 13 plants showed over-forecast tendencies for two or 12-hour ahead forecast, or both). The bias also tends to increase (slightly) with the increase in the forecast horizon.

3.8. We also found that wind forecast accuracy and bias tend to get worse with the increase in forecast horizon between 30 minutes and 36 hours before real-time.

3.9. Results for all forecast horizons are included in Table 7 in Appendix A.

Table 1 – Accuracy of 2 and 12-hour ahead wind power forecasts

			MAE (MW)		RMSE (MW)		MBE (MW)	
	Plant Name	Capacity	2-hours	12-hours	2-hours	12-hours	2-hours	12-hours
Mercury	Kaiwera Downs	43	4.75	5.39	7.10	8.09	1.50	1.98
	Turitea	222	12.91	15.23	19.40	22.61	0.00	0.03
Genesis Operated	Waipipi	133	15.94	16.54	24.87	25.17	0.03	-3.57
Manawa Operated	Mahinerangi	36	4.92	5.07	7.66	7.88	1.96	1.96
	Tararua stage 1	36	5.41	5.60	7.48	7.71	-1.86	-1.91
	Tararua stage 2	37	5.69	5.86	7.88	8.06	-2.71	-2.73
	Tararua stage 3	93	12.69	13.08	17.23	17.72	-0.58	-0.56

[17] Although Meridian's West Wind is technically larger than Waipipi, the plant has been in partial outage for most of 2023-2024, due to a failure of one of its transformers, with maximum output limited to around 100MW.

Meridian	Mill Creek	60	6.41	6.83	9.89	10.01	0.15	-0.77
	Te Uku	64.4	7.42	8.39	10.87	11.76	0.26	0.91
	Te Āpiti	90	10.38	13.41	15.01	18.22	-0.94	-3.18
	West Wind	100*	8.79	11.79	14.15	17.06	-0.22	-3.79
	White Hill	58	5.33	6.37	8.44	9.19	-0.02	-2.12
NZ Windfarms	Te Rere Hau	49	4.43	9.69	6.87	12.89	-0.29	-0.92

* See footnote 17

Seasonality has little impact on accuracy, but over-forecasting is more likely in the windier months

3.10. Table 2 shows the seasonality effects on wind power forecast accuracy for selected wind farms. The results show small variations in the RMSE and MBE metrics across the seasons. The accuracy seems to get slightly worse during Spring (6 out of 9 wind farms showed higher RMSE during that season). The differences between the highest and lowest RMSE per season were around 1.5MW on average between the selected wind farms.

3.11. Larger wind farms such as Mercury's Turitea, Genesis-operated Waipipi, and Meridian's Te Āpiti showed higher differences in RMSE. Since the variation is relatively small between the seasons, we conclude that seasonality does not play a major role in wind power forecasting inaccuracies for the wind farms included in this study. However, the MBE results indicate that over-forecasting might be expected to happen more often during the windier months (spring and summer),[18] as the bias tends to increase during those months.

Table 2 - Seasonality impacts on the 2-hour ahead wind power forecast accuracies

		RMSE (MW)				MBE (MW)			
	Plant Name	Autumn	Spring	Summer	Winter	Autumn	Spring	Summer	Winter
Mercury	Kaiwera Downs	7.34	7.76	7.25	5.87	1.88	1.9	1.03	1.05
	Turitea Wind Farm	17.97	20.67	18.70	19.83	0.38	0.79	0.68	-1.54
Genesis Operated	Waipipi	24.3	25.80	24.06	25.30	-0.12	0.24	-0.02	0.03
Manawa Operated	Tararua stage 1	7.25	7.47	8.04	7.20	-1.13	-2.06	-3.43	-1.00
	Tararua stage 3	16.2	17.68	17.70	17.41	0.85	-1.10	-3.93	1.46
Meridian	Mill Creek	9.64	10.06	9.60	10.23	0.16	0.08	0.33	0.06
	Te Āpiti	14.34	16.61	14.41	14.65	-0.47	-2.51	-1.13	0.20
	White Hill	8.88	8.71	7.68	8.38	0.28	-0.85	-0.32	0.68

[18] See: Electricity Authority - New Zealand Wind and Solar Generation Scenarios (2023)

NZ Windfarms	Te Rere Hau	6.39	7.71	6.16	7.13	-0.24	-0.60	-0.39	0.02

4. The choice of accuracy performance measure matters

4.1. Beyond average metrics, we also looked at the distribution of wind forecast inaccuracies[19] for the wind farms based on the:

(a) MW difference between actual and forecast wind power,

(b) Inaccuracies normalized by the available capacity[20] of the plant (represented as % of Available Capacity),

(c) Inaccuracies normalized by the forecast of generation potential (% from FOGP).[21]

4.2. Table 3 shows the 5th and 95th percentile of the 2-hour ahead wind power forecast inaccuracies for individual wind farms for the metrics discussed in the previous paragraph. In other words, it shows the interval where 90% of the data lies. Negative values represent over-forecast.

4.3. The MW inaccuracies show that wind farms with less than 50MW capacity tend to have a narrower MW interval than larger farms. The smallest 5 wind farms show an average range in inaccuracy of ~24MW (difference between the 95th and 5th percentiles), while the 5 largest farms (excluding West Wind) showed an average range of ~58MW.

4.4. NZ Windfarms' Te Rere Hau showed the narrowest inaccuracy range between the smaller farms (22.2MW), followed by Mercury's Kaiwera Downs (23.3MW). The latter, however, showed less tendency to over-forecast (-9.3MW versus -11.5MW). Between the 5 largest wind farms we can see an increase in the inaccuracy range with wind farm capacity. The largest farm (Mercury's Turitea), however, showed a range in values narrower than the second-largest wind farm (Waipipi – operated by Genesis), and closer to the third-largest farm (Manawa-operated Tararua stage 3).

4.5. The inaccuracies relative to the available capacity of the farms showed that larger plants had smaller inaccuracies (based on this measure) compared to smaller farms, on average. The five smaller plants had an average inaccuracy of 61.4% relative to their available capacity while the five largest farms (excluding Meridian's West Wind)[22] showed an average inaccuracy of ~54% of available capacity. Mercury's Turitea had the smallest average inaccuracy among all wind farms (29.1% of available capacity).

4.6. Mercury's wind farms also showed the lowest tendency to over-forecast when considering the inaccuracies relative to available capacity, with Turitea and Kaiwera Downs showing that 5% of the time over-forecast values were above 14.4% and

[19] Methodology is discussed in Appendix B.

[20] Available capacity: wind farm nominal capacity minus any outages uploaded to the Planned Outage Co-ordination Process (POCP).

[21] We used the last submitted FOGP for each plant and for each trading period for this analysis.

[22] Excluded since West Wind has been in partial outage for most of 2023-2024

21.8% of the plant's available capacity respectively. The average over-forecast inaccuracy between all wind farms was around 28.5%. Mercury's Turitea also showed the best values for the under-forecast case, followed by NZ Windfarms' Te Rere Hau.

4.7. The forecast differences relative to the last submitted FOGP of wind generation showed larger deviations compared to the other measures, the average inaccuracy being ~172% (on average, wind farms ranged from ~98% under-forecast to ~75% over-forecast, relative to FOGP). We considered only trading periods when the expected generation potential was above 10MW to avoid dealing with large errors that may arise when those values get close to zero.

4.8. However, we noted that the forecast differences from FOGP decrease considerably when we narrowed the interval for the data. For instance, taking the interval where 70% of the data lies (between the 15th and 85th percentiles),[23] we noticed that the average inaccuracy dropped to ~86% (53% under-forecast to 33% over-forecast), and for some plants such as Mercury's Kaiwera Downs, the over-forecast inaccuracies were as low as ~12% from FOGP.

4.9. Results for the remaining forecast horizons are shown in Table 8 to Table 11 in Appendix A. The results indicate a widening of the inaccuracy ranges (differences between 5^{th} and 95^{th} percentiles) with the increase in forecast horizon, indicating a worsening of the forecasting performance, as expected. There was a considerable widening of the inaccuracy range for the Te Rere Hau wind farm above the 2-hour ahead horizon. This tendency was also found in a previous study conducted by the Authority.[24]

4.10. In summary, the wind forecast performance can change depending on the reference it is assessed against; small-sized plants showed better results for the absolute MW and percent of FOGP references while large-sized plants often performed better relative to the percentage of available capacity.

[23] See Table 12 in Appendix A for more information.

[24] See: Electricity Authority - Accuracy of Wind and Load Forecasts (2022)

Table 3 – Performance of 2-hour ahead wind forecast inaccuracies relative to selected references

	Plant Name	Capacity (MW)	MW		% of Available Capacity		% of FOGP (where above 10MW)	
			5th perc	95th perc	5th perc	95th perc	5th perc	95th perc
Mercury	Kaiwera Downs	43	-9.3	14.0	-21.8	33.9	-37.3	117.6
	Turitea Wind Farm	222	-31.8	32.6	-14.4	14.7	-74.6	76.2
Genesis Operated	Waipipi	133	-40.5	41.2	-30.6	31.1	-114.7	116.7
Manawa Operated	Mahinerangi	36	-8.5	15.8	-24.2	44.9	-50.4	118.7
	Tararua stage 1	36	-13.8	10.7	-38.7	30.0	-90.2	81.5
	Tararua stage 2	37	-15.5	9.6	-42.0	26.2	-104.3	79.8
	Tararua stage 3	93	-29.0	28.9	-31.3	31.3	-95.5	93.7
Meridian	Mill Creek	60	-15.8	16.5	-26.8	28.0	-61.1	88.8
	Te Uku	64.4	-17.1	19.0	-28.0	31.2	-70.2	94.1
	Te Āpiti	90	-27.1	24.1	-31.0	27.6	-81.2	106.7
	West Wind	100*	-22.9	22.8	-27.5	27.2	-70.5	96.0
	White Hill	58	-13.6	14.6	-30.3	31.7	-62.0	105.3
NZ Windfarms	Te Rere Hau	49	-11.5	10.7	-23.5	21.8	-59.5	93.7

* See footnote 17

5. The current standard is stricter on larger generators

5.1. Currently, under Clause 13.86A(2) of the Code, an 'intermittent generator must not generate electricity during a trading period at a rate that is more than 30MW below the forecast of generation potential [FOGP] specified in the intermittent generator's final offer'.[25] In other words, participants owning/operating intermittent generators should submit final forecasts (usually one hour before real-time) within a 30MW over-forecast threshold relative to their actual generation.

5.2. The results in the previous section show that a performance standard based on an absolute MW threshold can pose a challenge for larger plants while being somewhat lenient on smaller ones. Wind farms in New Zealand typically have average capacity factors (ie, mean output over nominal capacity) around 30% to

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[25] See: Electricity Industry Participation Code 2010 (May 2024)

50%,[26] and since most of those farms have a nominal capacity of 100MW or less, it is easier for smaller generators to comply with such a threshold than it is for larger generators.

5.3. To handle this issue, the current standard could be replaced by a standard more suitable for small and large intermittent generators (for instance, a standard based on the percent of FOGP or the percent of available capacity, presented in the previous section) or even combined with another standard (for instance, combine a MW standard with the percent of available capacity).

5.4. From the distribution of wind over-forecast inaccuracies discussed in the previous section, we established the following forecast performance thresholds:

(a) Over-forecast error equal to or less than 30MW,

(b) Over-forecast error equal to or less than 20% of available capacity,

(c) Over-forecast error equal to or less than 20% of FOGP or 10MW (whichever is greater).[27]

5.5. The first threshold (over-forecast error equal to or less than 30MW) was selected to closely match the current threshold, while the percentage values (20% of available capacity and 20% of FOGP) were based on the results of the best-performing farms discussed in the previous section (but still above their actual results). Table 4 shows the frequency with which individual wind farms cross these thresholds for 2-hour ahead forecasts.

5.6. Mercury's Kaiwera Downs (43MW) showed the best performance relative to the MW threshold, as only 0.1% of the data was above the 30MW over-forecast mark. This result is not very different from the remaining wind farms below 50MW capacity. Larger wind farms such as Turitea, Waipipi, Tararua stage 3, and Te Āpiti crossed the threshold between 3.8% and 8.4% of the time.

5.7. Mercury's Turitea (222MW) showed the best results for the percent of available capacity, crossing the 20% over-forecast threshold only 2.2% of the time. The second-best performing farm was Mercury's Kaiwera Downs (5.8%), showing that despite their different capacities, both Mercury's plants performed well. Meridian, which operates a portfolio of large and small wind farms of various sizes, was above the mark ~9.5% of the time, on average, across its plants, and ahead of Manawa (~15% of the time, on average, considering all its wind farms).

5.8. Manawa-operated Mahinerangi (36MW) performed best relative to the FOGP threshold, crossing the mark 3.9% of the time, closely followed by Mercury's Kaiwera Downs (above the mark 4.4% of the time). The only two other wind farms crossing the threshold less than 10% of the time were Te Rere Hau and White Hill. In other words, smaller farms performed better than larger farms (based on the % of FOGP threshold), possibly due to them being below 10MW inaccuracy more often than larger farms.

5.9. Results for other forecast horizons are shown in Tables 13 to 15 (Appendix A)

[26] See: MBIE Wind Generation Stack Update (2020)

[27] While wind forecast inaccuracies below 10MW per wind farm should not impact the market (since the generation is expected to be low), small values in the divisor can bias the errors.

Table 4 - Comparative performance of different thresholds for 2-hour ahead forecasts

	Plant Name	Capacity	Over-forecast error > 30MW	Over-forecast error > 20% of available capacity	Over-forecast error > greater of 20% of FOGP or 10MW
Mercury	Kaiwera Downs	43	0.1%	5.8%	4.4%
	Turitea Wind Farm	222	5.6%	2.2%	18.4%
Genesis Operated	Waipipi	133	8.4%	10.1%	21.1%
Manawa Operated	Mahinerangi	36	0.2%	6.4%	3.9%
	Tararua stage 1	36	0.2%	18.8%	11.4%
	Tararua stage 2	37	0.2%	22.0%	14.3%
	Tararua stage 3	93	4.6%	12.8%	22.1%
Meridian	Mill Creek	60	0.8%	8.2%	10.2%
	Te Uku	64.4	1.0%	9.2%	12.0%
	Te Āpiti	90	3.8%	11.3%	19.5%
	West Wind	100*	2.6%	8.7%	14.8%
	White Hill	58	0.4%	9.7%	8.3%
NZ Windfarms	Te Rere Hau	49	0.2%	6.8%	6.6%

* See footnote 17

6. Better forecasting should enhance security of supply and contribute to more accurate prices

6.1. This section provides a sense of the change in forecast prices that the proposed over-forecast inaccuracy thresholds discussed in the previous section might cause. To do this, we modelled six scenarios that simulate prices assuming wind generation forecast inaccuracies were never above the proposed thresholds. For the modelling we used the vSPD[28] model with data between 1 November 2022 and 10 October 2023.

[28] vSPD stands for vectorised Scheduling, Pricing and Dispatch. The vSPD model is a precise replica of the Scheduling, Pricing and Dispatch (SPD) software used by the System Operator. The software returns the optimal prices and quantities for the New Zealand Electricity Market to supply demand at any given trading interval.

6.2. We created the scenarios according to the following thresholds:[29]

- **Scenario 1a**: capping the two-hour ahead forecast inaccuracies to 30MW over-forecast (closest to the current threshold).
- **Scenario 1b**: capping *both* the two-hour ahead *and* 12-hour ahead forecast inaccuracies to 30MW over-forecast.
- **Scenario 2a**: capping the two-hour ahead forecast inaccuracies to 20% over-forecast (relative to available capacity)
- **Scenario 2b**: capping *both* the two-hour ahead *and* 12-hour ahead forecast inaccuracies to 20% over-forecast (relative to available capacity)
- **Scenario 3a**: capping the two-hour ahead forecast inaccuracies to the greater of 20% over-forecast (relative to FOGP) or 10MW.
- **Scenario 3b**: capping *both* the two-hour *and* 12-hour ahead forecast inaccuracies to the greater of 20% over-forecast (relative to FOGP) or 10MW.

6.3. We decided to focus on over-forecast situations since it would allow us to compare the proposed thresholds against the current performance standard. The results in this section provide an indication of how stricter standards for intermittent generation could affect market prices.

6.4. For each scenario, every time a wind farm exceeded the thresholds, its wind generation offers in the vSPD RTD schedules were increased to match the upper bound of the respective threshold (for instance, suppose that for scenario 1a, a wind farm is forecast to generate 50MW two hours ahead of real-time but ends up generating only 10MW. In this case we would increase the generation to 20MW so the difference between forecast and actual becomes 30MW).

6.5. The vSPD model was also used to create the reference case, allowing the model to solve each trading period using unchanged wind generation offers, to serve as a reference against the scenarios. We compared the average reference prices to the modelled prices for the trading periods where the thresholds were crossed.

[29] Methodology is described in Appendix B.

Table 5 - Changes to spot prices according to each scenario

	Number of data points	Average modelled price ($/MWh)	Decrease in price relative to reference (%)
Scenario 1a	2,655,646	68.32	6.93%
Scenario 1b	3,913,103	72.52	7.00%
Scenario 2a	6,230,896	75.16	9.65%
Scenario 2b	7,229,136	77.56	12.10%
Scenario 3a	8,176,430	80.28	14.82%
Scenario 3b	8,336,796	80.61	15.96%

6.6. Since the scenarios are progressively stricter, the number of data points (trading periods where the threshold was crossed for each wind farm) was relatively low for the 30MW rule (scenarios 1a and 1b), but much higher for scenarios 3a and 3b, as shown in Table 5. This is expected since intermittent generators already must comply with a similar rule to scenario 1. But it also shows that if wind farms were to comply with stricter standards at least some of them would need to improve their wind power forecasting capabilities.

6.7. As expected, the results indicate a decrease in the average spot prices compared to the reference case, as shown in Table 5. The percentage change in price compared to the reference was around 7%-16%. Compared to scenario 1, both scenarios 2 and 3 show a greater impact on price.

6.8. These results are consistent with market observations from the Authority,[30] which reported that episodes of low wind generation are often related to high spot prices. The Authority also observed that the high spot price episodes are also often related to high wind forecast inaccuracies.

6.9. However, it is important to note that having stricter forecast performance standards will not increase the amount of wind generation but will likely decrease the frequency and volume of inaccurate offers, which in its turn could hopefully incentivise greater slow-start thermal offers where desirable, leading to a more efficient and more secure generation mix, and potentially contributing to lowering the overall real-time prices.

6.10. Finally, since all the scenarios using both two and 12-hour thresholds ("b" scenarios) show a further impact on price, having an inaccuracy threshold encompassing *both* two *and* 12-hour ahead forecasts seems advantageous. Such a threshold in place could potentially also be beneficial to enhance security of supply by providing slow-start thermal units with a more accurate picture of future intermittent generation levels further ahead of real-time.

[30] See, for instance: Trading Conduct Report – Market Monitoring Weekly Report for the week of 13 – 19 August 2023

7. Better forecasting has an even more significant impact during low residual situations

7.1. We also looked at the overall impact of forecasting errors for trading periods with low generation residuals (below 300MW). [31] These are likely the situations when forecasting errors matter the most for security of supply.

7.2. As shown in Table 6, there are fewer data points compared to the previous table. This is expected since low-residual events are relatively rare. However, we can see that the impact of lower wind forecast inaccuracies in the market during these times is even more pronounced.

7.3. Looking at times when there were low residuals in the system, we could see a greater impact on prices compared to regular periods. The change in prices during periods of low generation residuals was between ~15% to ~41% compared to the reference prices for each scenario. It is interesting to note that, in this case, scenario 1b had a smaller impact on prices compared to 1a. The remaining scenarios showed a progressively greater impact on prices.

7.4. Based on the results, it is possible that having different standards for periods of low residuals or high electricity demand (ie, a stricter threshold for forecast errors during these times) compared to periods of higher residuals (less strict threshold) could be an option to enhance security of supply.

7.5. We note, as pointed out earlier, that the over-forecast thresholds were developed to compare against the current threshold only, and we are not encouraging having wind power forecasting standards designed for over-forecast events only, as it could produce unintended consequences such as biassing the forecasts downwards.

7.6. Finally, the proposed thresholds discussed in this document are possibilities, and the key message is that an updated performance standard for intermittent generators must be fair to both small and large generators.

[31] The residual is the amount of spare offered generation capacity above that needed to meet demand and reserve requirements.

Table 6 - Modelled changes in spot prices during periods of low generation residual in the market

	Number of data points	Average modelled price ($/MWh)	Decrease in price relative to reference (%)
Scenario 1a	29,931	257.23	21.83%
Scenario 1b	43,592	291.20	15.31%
Scenario 2a	49,906	250.77	19.68%
Scenario 2b	70,391	262.24	22.75%
Scenario 3a	82,457	285.98	29.50%
Scenario 3b	83,510	240.76	41.09%

8. Next steps

8.1. In February 2025, we published a Decision Paper confirming the final amendments the Authority will make to the Code to give effect to the hybrid forecasting arrangement.[32] The Code amendments will come into effect on 1 July 2025.

8.2. The Authority is also undertaking a procurement process to select a centralised forecasting service provider. We expect to be able to select our preferred provider in the coming months, and for the successful provider to begin providing services on 1 July 2025.

8.3. This analysis will inform the forecast performance standards that the Authority will agree with the successful provider.

[32] See footnote 10.

Appendix A Further results

Results pertaining to Section 2

Table 7 - Accuracy of wind power forecasts between 0.5 and 36-hours ahead of real-time

			MAE_MW					MBE_MW					RMSE_MW				
		Hours Ahead	0.5	2	4	12	36	0.5	2	4	12	36	0.5	2	4	12	36
	Plant Name	Capacity															
Mercury	Kaiwera Downs	43	3.98	4.75	5.16	5.39	5.81	0.99	1.50	1.77	1.98	2.13	6.10	7.10	7.68	8.09	8.59
	Turitea Wind Farm	222	10.11	12.91	14.19	15.23	17.30	-0.26	0.00	0.01	0.03	0.26	16.26	19.40	21.00	22.61	25.36
Genesis Operated	Waipipi	133	10.96	15.94	15.82	16.54	19.17	0.11	0.03	-2.74	-3.57	-4.65	18.07	24.87	24.38	25.17	28.63
Manawa Operated	Mahinerangi	36	3.44	4.92	4.97	5.07	5.34	-0.33	1.96	1.97	1.96	1.78	5.74	7.66	7.71	7.88	8.21
	Tararua stage 1	36	2.60	5.41	5.46	5.60	5.94	0.02	-1.86	-1.86	-1.91	-1.87	4.30	7.48	7.55	7.71	8.13
	Tararua stage 2	37	2.67	5.69	5.74	5.86	6.17	0.00	-2.71	-2.71	-2.73	-2.72	4.45	7.88	7.93	8.06	8.44

			MAE_MW					MBE_MW					RMSE_MW				
		Hours Ahead	0.5	2	4	12	36	0.5	2	4	12	36	0.5	2	4	12	36
	Plant Name	Capacity															
	Tararua stage 3	93	6.85	12.69	12.74	13.08	13.92	-0.09	-0.58	-0.53	-0.56	-0.31	10.40	17.23	17.28	17.72	18.78
Meridian	Mill Creek	60	4.21	6.41	6.62	6.83	7.64	0.11	0.15	-0.76	-0.77	-0.66	6.79	9.89	9.75	10.01	10.99
	Te Uku	64.4	4.86	7.42	8.11	8.39	9.13	0.05	0.26	0.95	0.91	0.78	7.43	10.87	11.36	11.76	12.69
	Te Āpiti	90	6.68	10.38	13.11	13.41	14.36	-0.67	-0.94	-3.22	-3.18	-3.13	10.51	15.01	17.89	18.22	19.24
	West Wind	100*	5.69	8.79	11.46	11.79	12.68	-0.39	-0.22	-3.64	-3.79	-4.13	9.71	14.15	16.53	17.06	18.33
	White Hill	58	3.49	5.33	6.19	6.37	6.94	-0.12	-0.02	-2.02	-2.12	-2.56	5.82	8.44	8.91	9.19	9.99
NZ Windfarms	Te Rere Hau	49	2.63	4.43	9.64	9.69	10.66	-0.33	-0.29	-0.93	-0.92	-0.81	4.50	6.87	12.83	12.89	13.98

Results pertaining to Section 3

Table 8 - Performance of 30-minute ahead wind forecast inaccuracies relative to selected references

	Plant Name	Capacity (MW)	MW		% of Available Capacity		% from FOGP (where above 10MW)	
			5th perc	95th perc	5th perc	95th perc	5th perc	95th perc
Mercury	Kaiwera Downs	43	-8.4	11.5	-19.8	27.9	-33.5	109.4
	Turitea Wind Farm	222	-26.2	25.8	-11.9	11.7	-49.7	74.7
Genesis Operated	Waipipi	133	-27.8	28.6	-21.0	21.6	-63.6	111.7
Manawa Operated	Mahinerangi	36	-9.4	8.9	-26.8	25.3	-50.6	100.6
	Tararua stage 1	36	-6.6	6.5	-18.3	18.2	-34.4	68.4
	Tararua stage 2	37	-7.1	6.8	-19.2	18.6	-37.1	75.0
	Tararua stage 3	93	-16.3	16.5	-17.6	17.9	-48.7	81.0
Meridian	Mill Creek	60	-10.3	10.9	-17.5	18.9	-39.4	69.2
	Te Uku	64.4	-11.7	12.3	-18.9	20.1	-44.6	75.6
	Te Āpiti	90	-18.1	15.5	-20.8	17.9	-50.4	90.0
	West Wind	100*	-16.0	14.3	-19.3	17.2	-44.2	76.3
	White Hill	58	-9.4	9.1	-20.8	19.9	-41.8	90.1
NZ Windfarms	Te Rere Hau	49	-6.9	6.0	-14.0	12.2	-36.2	64.9

Table 9 - Performance of 4-hour ahead wind forecast inaccuracies relative to selected references

	Plant Name	Capacity (MW)	MW		% of Available Capacity		% of FOGP (where above 10MW)	
			5th perc	95th perc	5th perc	95th perc	5th perc	95th perc
Mercury	Kaiwera Downs	43	-9.8	15.6	-22.9	37.9	-39.4	126.5
	Turitea Wind Farm	222	-34.2	35.2	-15.4	15.9	-84.4	76.9
Genesis Operated	Waipipi	133	-44.8	34.4	-34.5	26.0	-146.9	83.1
Manawa Operated	Mahinerangi	36	-8.5	15.8	-24.4	45.0	-50.1	118.4
	Tararua stage 1	36	-13.9	10.8	-39.0	30.2	-90.0	81.8
	Tararua stage 2	37	-15.5	9.8	-42	26.5	-104.2	79.7
	Tararua stage 3	93	-29.1	29.1	-31.4	31.6	-96.2	93.0
Meridian	Mill Creek	60	-16.8	15.4	-28.6	26.2	-65.4	72.1
	Te Uku	64.4	-15.3	22.0	-25.0	36.1	-64.7	81.9
	Te Āpiti	90	-34.0	26.4	-39.0	30.5	-109.1	87.8
	West Wind	100*	-29.9	23.2	-36.6	27.9	-117.8	78.2
	White Hill	58	-16.0	12.7	-35.8	27.1	-84.8	81.4
NZ Windfarms	Te Rere Hau	49	-23.3	21.2	-47.5	43.4	-106.3	105.7

Table 10 - Performance of 12-hour ahead wind forecast inaccuracies relative to selected references

	Plant Name	Capacity (MW)	MW		% of Available Capacity		% of FOGP (where above 10MW)	
			5th perc	95th perc	5th perc	95th perc	5th perc	95th perc
Mercury	Kaiwera Downs	43	-10.0	16.7	-23.5	40.4	-40.0	131.7
	Turitea Wind Farm	222	-36.8	38.0	-16.7	17.2	-95.3	79.3
Genesis Operated	Waipipi	133	-47.7	34.7	-36.6	26.1	-162.0	81.1
Manawa Operated	Mahinerangi	36	-8.6	16.1	-24.5	46.0	-51.3	118.0
	Tararua stage 1	36	-14.3	11.1	-40.0	30.9	-89.6	83.1
	Tararua stage 2	37	-15.7	10.1	-42.6	27.5	-102.8	80.7
	Tararua stage 3	93	-29.9	29.8	-32.3	32.3	-100.4	92.8
Meridian	Mill Creek	60	-17.2	15.9	-29.4	26.9	-67.8	74.2
	Te Uku	64.4	-15.8	22.8	-26.4	37.1	-69.9	82.4
	Te Āpiti	90	-34.5	27.0	-39.6	31.1	-111.3	88.4
	West Wind	100*	-31.0	23.6	-38.1	28.4	-119.5	78.9
	White Hill	58	-16.4	12.9	-36.8	27.7	-87.4	82.1
NZ Windfarms	Te Rere Hau	49	-23.4	21.2	-47.7	43.4	-105.4	106.1

Table 11 - Performance of 36-hour ahead wind forecast inaccuracies relative to selected references

	Plant Name	Capacity (MW)	MW		% of Available Capacity		% of FOGP (where above 10MW)	
			5th perc	95th perc	5th perc	95th perc	5th perc	95th perc
Mercury	Kaiwera Downs	43	-10.5	17.7	-24.7	43.0	-42.5	128.8
	Turitea Wind Farm	222	-40.5	43.5	-18.4	19.6	-109.1	80.0
Genesis Operated	Waipipi	133	-55.5	38.6	-42.4	29.1	-189.9	84.1
Manawa Operated	Mahinerangi	36	-9.6	16.6	-27.3	47.3	-52.5	117.9
	Tararua stage 1	36	-15.0	12.1	-42.1	33.6	-88.1	85.6
	Tararua stage 2	37	-16.3	11.0	-44.5	29.9	-100.5	83.1
	Tararua stage 3	93	-31.6	32.2	-34.2	34.8	-107.4	93.4
Meridian	Mill Creek	60	-18.6	18.1	-31.8	30.9	-73.7	80.0
	Te Uku	64.4	-17.6	24.4	-29.5	39.5	-78.7	83.8
	Te Āpiti	90	-35.8	29.7	-40.8	34.2	-119.7	90.3
	West Wind	100*	-33.7	25.2	-41.4	30.2	-125.6	79.9
	White Hill	58	-18.6	13.5	-41.1	29.1	-94.3	82.3
NZ Windfarms	Te Rere Hau	49	-25.0	23.4	-51.0	47.8	-103.1	109.6

Table 12 – Forecast performance in percent of FOGP relative to selected percentiles - 2-hour ahead forecasts

	Plant Name	Capacity (MW)	% from FOGP (and above 10MW)					
			5th perc	10th perc	15th perc	85th perc	90th perc	95th perc
Mercury	Kaiwera Downs	43	-37.3	-21.0	-11.3	63.6	82.7	117.6
	Turitea Wind Farm	222	-74.6	-48.0	-33.0	37.1	51.5	76.2
Genesis Operated	Waipipi	133	-114.7	-69.2	-46.6	56.6	77.0	116.7
Manawa Operated	Mahinerangi	36	-50.4	-25.1	-15.3	76.0	88.2	118.7
	Tararua stage 1	36	-90.2	-62.9	-46.5	45.4	62.0	81.5
	Tararua stage 2	37	-104.3	-72.7	-54.2	41.3	58.5	79.8
	Tararua stage 3	93	-95.5	-60.4	-43.1	62.4	74.8	93.7
Meridian	Mill Creek	60	-61.1	-37.0	-24.0	41.8	58.1	88.8
	Te Uku	64.4	-70.2	-44.2	-29.2	53.2	68.4	94.1
	Te Āpiti	90	-81.2	-53.1	-39.7	55.7	74.0	106.7
	West Wind	100*	-70.5	-44.6	-30.6	45.7	64.0	96.0
	White Hill	58	-62.0	-37.8	-25.6	59.4	77.4	105.3
NZ Windfarms	Te Rere Hau	49	-59.5	-41.0	-29.3	49.1	64.9	93.7

Results pertaining to Section 4

Table 13 - Comparative performance of different thresholds for 30-minute ahead forecasts

	Plant Name	Capacity	Over-forecast error > 30MW	Over-forecast error > 20% of available capacity	Over-forecast error > greater of 20% of FOGP or 10MW
Mercury	Kaiwera Downs	43	0.1%	4.9%	3.7%
	Turitea Wind Farm	222	3.8%	1.4%	13.2%
Genesis Operated	Waipipi	133	4.3%	5.4%	14.6%
Manawa Operated	Mahinerangi	36	0.1%	8.0%	4.5%
	Tararua stage 1	36	0.0%	4.3%	2.0%
	Tararua stage 2	37	0.0%	4.7%	2.5%
	Tararua stage 3	93	0.9%	3.6%	10.2%
Meridian	Mill Creek	60	0.2%	3.8%	5.1%
	Te Uku	64.4	0.2%	4.5%	6.5%
	Te Āpiti	90	1.7%	5.3%	11.3%
	West Wind	100*	1.0%	4.7%	8.9%
	White Hill	58	0.2%	5.4%	4.4%
NZ Windfarms	Te Rere Hau	49	0.1%	2.4%	2.3%

Table 14 - Comparative performance of different thresholds for 4-hour ahead forecasts

	Plant Name	Capacity	Over-forecast error > 30MW	Over-forecast error > 20% of available capacity	Over-forecast error > greater of 20% of FOGP or 10MW
Mercury	Kaiwera Downs	43	0.1%	6.3%	4.9%
	Turitea Wind Farm	222	6.6%	2.7%	20.4%
Genesis Operated	Waipipi	133	9.7%	11.7%	23.9%
Manawa Operated	Mahinerangi	36	0.2%	6.4%	4.0%
	Tararua stage 1	36	0.2%	18.9%	11.5%
	Tararua stage 2	37	0.3%	22.0%	14.5%
	Tararua stage 3	93	4.6%	12.8%	22.1%
Meridian	Mill Creek	60	1.0%	9.2%	11.5%
	Te Uku	64.4	0.7%	7.9%	11.1%
	Te Āpiti	90	7.2%	18.1%	27.6%
	West Wind	100*	5.0%	17.2%	26.5%
	White Hill	58	0.6%	15.5%	12.9%
NZ Windfarms	Te Rere Hau	49	1.3%	21.9%	21.1%

Table 15 - Comparative performance of different thresholds for 12-hour ahead forecasts

	Plant Name	Capacity	Over-forecast error > 30MW	Over-forecast error > 20% of available capacity	Over-forecast error > greater of 20% of FOGP or 10MW
Mercury	Kaiwera Downs	43	0.2%	6.4%	5.1%
	Turitea Wind Farm	222	7.6%	3.1%	22.0%
Genesis Operated	Waipipi	133	10.9%	13.2%	25.8%
Manawa Operated	Mahinerangi	36	0.3%	6.5%	4.1%
	Tararua stage 1	36	0.2%	19.3%	11.8%
	Tararua stage 2	37	0.3%	22.3%	14.6%
	Tararua stage 3	93	4.9%	13.1%	22.5%
Meridian	Mill Creek	60	1.0%	9.7%	12.0%
	Te Uku	64.4	0.9%	8.5%	11.7%
	Te Āpiti	90	7.4%	18.4%	28.2%
	West Wind	100*	5.5%	17.6%	27.0%
	White Hill	58	0.8%	16.1%	13.5%
NZ Windfarms	Te Rere Hau	49	1.4%	22.0%	21.2%

Table 16 - Comparative performance of different thresholds for 36-hour ahead forecasts

	Plant Name	Capacity	Over-forecast error > 30MW	Over-forecast error > 20% of available capacity	Over-forecast error > greater of 20% of FOGP or 10MW
Mercury	Kaiwera Downs	43	0.1%	7.0%	5.6%
	Turitea Wind Farm	222	9.0%	4.1%	24.7%
Genesis Operated	Waipipi	133	13.7%	16.1%	29.7%
Manawa Operated	Mahinerangi	36	0.4%	7.5%	4.7%
	Tararua stage 1	36	0.2%	20.1%	12.6%
	Tararua stage 2	37	0.3%	23.1%	15.5%
	Tararua stage 3	93	5.7%	13.7%	23.3%
Meridian	Mill Creek	60	1.2%	11.0%	13.6%
	Te Uku	64.4	1.2%	10.3%	13.7%
	Te Āpiti	90	8.0%	19.6%	29.7%
	West Wind	100*	6.6%	19.0%	28.4%
	White Hill	58	1.3%	18.3%	15.6%
NZ Windfarms	Te Rere Hau	49	2.1%	24.3%	23.5%

Appendix B Methodology

B.1. This section details the methods used to derive the results shown in the previous sections. We divided the study into two parts; the first part covers the performance analysis of wind forecast offers submitted by intermittent generators. The second part details the scenarios designed to estimate the effect of decreased intermittent generation forecast inaccuracy on forecast prices.

Wind forecast performance evaluation

B.2. To calculate the inaccuracies in wind generation forecast by generator, we used five data sets, each ranging from 1 January 2021 to 31 October 2024. The data sets are related to wind generation, wind forecast, forecast of generation potential, and wind farm capacity.

B.3. As a first step, the RTD wind generation and PRSS wind forecast data sets were combined to calculate the MW difference between generated and forecast wind generation[33],

$$Forecast_{differences}[MW] = Wind_{generation} - Wind_{forecast} \tag{1}$$

B.4. Then the capacity information and outages of each of the farms were used to adjust the available capacity of a certain wind farm at each given time,

$$Farm_{adjusted\ capacity} = Farm_{nominal\ capacity} - Farm_{outages} \tag{2}$$

B.5. Using the values from (1) and (2), we calculated the available difference between wind generation and forecast for each plant (as a % of available capacity $[\%CPTY]$)

$$Forecast_{differences}[\%\ CPTY] = \left(Forecast_{differences}/Farm_{adjusted\ capacity}\right) \cdot 100 \tag{3}$$

B.6. Using the values from (1), we calculated the difference between wind generation and forecast generation for each plant (as a % of the last submitted FOGP)

$$Forecast_{differences}[\%\ FOGP] = \left(Forecast_{differences}/Wind_{FOGP}\right) \cdot 100 \tag{4}$$

B.7. The methodology applies to either two, six or 12-hour ahead forecasts.

B.8. The last step involved computing the relevant statistics. We analysed the distribution of data points per participant and the frequency of occurrence of certain events:

a. We calculated the distribution of wind forecast inaccuracies per participant, to provide a sense of the difference between actual and forecast generation.

b. We calculated the frequency of the relevant events, such as the number of times wind forecasts were below 20% of available capacity or below 20% of

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[33] RTD stands for real-time dispatch schedule and PRSS is the price-responsive schedule. RTD represents the energy dispatched by the System Operator based on the results of the Scheduling, Pricing and Dispatch (SPD) model for each intermittent generating station. PRSS informs the expected output of each intermittent generating station, effectively named as $Wind_{forecast}$

FOGP – a value chosen based on the distribution of wind forecast inaccuracies, taking the most accurate result (ie, generator) as a reference.

Modelled changes in spot prices

B.9. We created six scenarios to test the impact of the decrease in wind forecast inaccuracies (effectively the increase in wind generation)[34] on electricity wholesale spot prices. To create the scenarios, we used roughly one year of wind generation and forecast data, from 1 November 2022 to 10 October 2023, selecting the trading periods when high wind forecast inaccuracies occurred. The threshold for high inaccuracy and the forecast window changes according to each scenario:

- **Scenario 1a**: capping the two-hour ahead forecast inaccuracies to 30MW over-forecast (closest to the current threshold).
- **Scenario 1b**: capping *both* the two-hour ahead *and* 12-hour ahead forecast inaccuracies to 30MW over-forecast.
- **Scenario 2a**: capping the two-hour ahead forecast inaccuracies to 20% over-forecast (relative to available capacity)
- **Scenario 2b**: capping *both* the two-hour ahead *and* 12-hour ahead forecast inaccuracies to 20% over-forecast (relative to available capacity)
- **Scenario 3a**: capping the two-hour ahead forecast inaccuracies to the greater of 20% over-forecast (relative to FOGP) or 10MW.
- **Scenario 3b**: capping *both* the two-hour *and* 12-hour ahead forecast inaccuracies to the greater of 20% over-forecast (relative to FOGP) or 10MW.

B.10. Therefore, scenarios were designed to be increasingly more restrictive. As a second step, the North Island residual information was used to filter out the modelled results according to trading periods when low generation residuals (below 300MW) occurred, as shown in Table 6.

B.11. To model the adjusted wind generation, we used the thresholds developed for each of the scenarios; whenever the inaccuracy in intermittent generation offers crossed the thresholds, we calculated the adjusted wind generation level so the difference between offers and generation would remain at the threshold, thus effectively modelling what would be the "ideal" generation.

B.12. For the scenarios where over forecast was above 30 MW, the ideal generation was adjusted according to Equation 5,

$$IdealGeneration\ [MW] = Wind_{forecast} - 30. \quad (5).$$

B.13. For the scenarios where over forecast was above 20% of the adjusted wind farm capacity, the ideal generation was adjusted according to

$$IdealGeneration\ [MW] = +Wind_{forecast} - \left(0.2 \cdot Farm_{adjusted\ capacity}\right) \quad (6),$$

[34] This has the effect of lowering real-time prices. In practice, wind forecasts would be reduced to within the proposed accuracy threshold of actual wind generation. This would have the effect of raising forecast prices, hopefully incentivising greater slow-start thermal offers where desirable, leading to a more efficient and more secure generation mix. Even though the direction of price movements is opposite, the magnitude will be similar.

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B.14. Finally, for the scenarios where over forecast was above the greater of 20% of FOGP or 10 MW, the ideal generation was adjusted according to

$$IdealGeneration\,(MW) = \max\left((-0.2 \cdot FOGP + Wind_{forecast}), 10\right) \quad (7).$$

The average prices for each of the scenarios were calculated as the average of electricity price times at all nodes and for all trading periods between 1 November 2022 and 10 October 2023.