Review of forecasting provisions for intermittent generators in the spot market

Decision paper

11 July 2024

ELECTRICITY AUTHORITY
TE MANA HIKO

Executive summary

This paper presents the key findings and decisions from the Authority's review of forecasting provisions for intermittent generators.

We expect most new electricity generation in New Zealand to come from intermittent generation – generation that is reliant on external factors, like wind or solar. In 2022 the Authority investigated the accuracy of wind generation and found that forecasts are often inaccurate and unreliable until close to real time. This can cause problems for the power system, and risks increasing costs for consumers. These problems could be exacerbated as we increase our reliance on intermittent generation. To help improve security of supply and outcomes for consumers the Authority has made decisions to improve forecasting for intermittent generation.

The Authority has decided to implement a hybrid forecasting arrangement. A hybrid arrangement provides a centrally procured forecast of intermittent generation, with the ability for generators to submit offers based on their own forecast if they meet the prescribed accuracy standards. This would require their own forecast to be consistently at least as accurate as the centralised forecast.

Better forecasts will increase the accuracy of price signals, which contributes to the most efficient and lowest cost sources of generation being dispatched. This is a key initiative to support affordable electricity for consumers.

The hybrid arrangement will also support the development of a market for generation forecasting and foster innovation through creating competitive tension between the centralised forecaster and other providers. This is expected to lead to better accuracy compared to a fully centralised forecast, which in turn will improve affordability for consumers. Innovator-developers will also benefit from this initiative as it will reduce regulatory and information barriers to participation by new entrants. The procurement process will also explore the potential for a centralised forecaster to submit offers on behalf of generators on a commercial basis.

The Authority wants intermittent generators to remain responsible for the reliability of the generation offers that they submit to the system operator (using the wholesale information trading system (WITS)). This principle has guided the detailed design of the hybrid option.

The cost of the forecasting arrangement will be apportioned across all generators as they all derive benefits from more accurate forecasts. We acknowledge that the hybrid arrangement will add some additional costs to participants, but on balance no more than the fully centralised forecasting option because many intermittent generators will continue to procure and use their own weather forecasts for a range of purposes.

The Authority will progress the hybrid arrangement in the second half of 2024, with the aim to have it in place by winter 2025.

In the interim we are putting additional measures in place to improve forecasting performance. We have recently issued guidance to intermittent generators on the interpretation of the current Code requirements relating to forecasts and offers close to real time. We will also shortly begin publishing forecast accuracy for each intermittent generator and generation site across different timeframes (on a monthly scale). This will improve transparency of the difference between intermittent generation forecasts of generation potential and actual generation.

One of the objectives of improving the accuracy of intermittent generation forecasts and offers is to improve security of supply. The Authority also has a range of other workstreams underway to address security of supply issues. The ongoing future security and resilience work programme is ensuring that appropriate Code requirements for new generating technologies to support power system resilience are in place. The upcoming potential solutions for peak electricity capacity issues decision will outline the market incentive work that the Authority intends to undertake to support near-term security of supply.

Contents

1. Purpose

1.1. This paper presents the key findings and decisions from the Electricity Authority Te Mana Hiko's (Authority) review of forecasting provisions for intermittent generation. It follows on from the *Issues and options paper: Review of forecasting provisions for intermittent generators in the spot market* published in June 2023.

2. Background to the review

Our forecasting arrangements for intermittent generation are outdated and do not incentivise accurate forecasting

2.1. Intermittent sources of generation[1] will play an important role in expanding generation capacity to help meet projected demand growth.[2]

2.2. Intermittent generation is offered into the spot market based on forecasts starting approximately 36 hours ahead of real time. Intermittent generators in New Zealand are currently required to produce their own forecasts to inform how much electricity they expect to be able to generate over each trading period.

2.3. The current provisions in the Electricity Industry Participation Code 2010 (Code) that specify intermittent generators' forecast, offer and performance requirements were put in place in September 2019. At the time, installed wind capacity (the only form of intermittent generation at the time) made up approximately 6% of total installed capacity.

2.4. Under these rules, intermittent generators are required to submit:

(a) an initial offer at least 71 trading periods ahead of real time based on a reasonable expectation of how much electricity it will be able to generate; and

(b) offers, and a forecast of generation potential (FOGP) based on a resource persistence model for each trading period (unless otherwise agreed with the Authority) within two hours of a trading period.[3]

2.5. There are currently no requirements or incentives in the Code around the frequency[4] and accuracy of intermittent generation offers more than two hours ahead of a trading period.

2.6. Figure 1 illustrates the current offer and forecast requirements that apply to most intermittent generators.

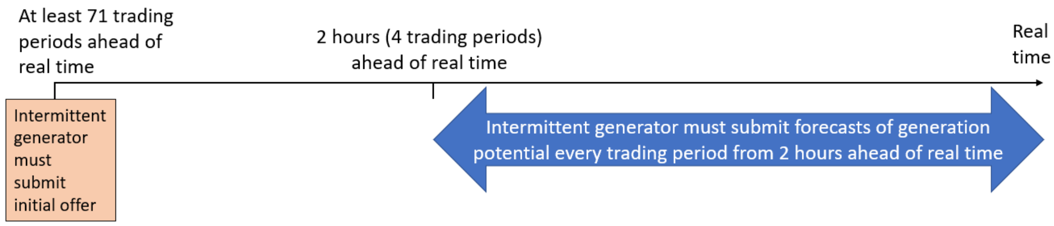
[1] Intermittent generation is electrical energy that is not continuously available due to external factors that cannot be controlled. Sources of intermittent generation include wind and solar energy.

[2] See more detail on the role of intermittent generation at paragraph 3.10.

[3] Refer to Form 2 in Schedule 13.1 and clause 13.18A of the Code.

[4] Intermittent generators must update their offers every two hours from 36 hours out, but in theory these offers can be any value and not based on updated forecasts.

Figure 1: Current offer and forecast requirements



2.7. An intermittent generator must submit a report to the Authority if an individual plant generates 30MW below the FOGP in their final offer.[5] There is no such requirement if an individual plant generates 30MW above the FOGP in their final offer.

2.8. The Authority receives a variable number of reports each month (for example, in January 2024 we received reports from four participants, while in March 2024 only one report was received). There are no regulatory consequences for inaccurate intermittent generation forecasts and offers.

2.9. The system operator currently procures a wind generation forecast for use in its system security assessment processes. An aggregated version of this forecast is published on em6.[6]

2.10. Publication of this data allows participants to see whether the aggregated wind generation offers are close to the wind generation forecast procured by the system operator. This published wind forecast includes confidence limits for that forecast. This allows participants to see when there may be periods of high uncertainty in wind generation output, with potential impacts on forecast price, so they can plan their consumption and generation accordingly.

2.11. In October 2022, the Authority published an information paper that investigated the accuracy of wind generation and demand forecasts[7] and bids. The Authority observed that intermittent generation forecasts are often inaccurate until the last three and a half hours before real time.

2.12. Inaccurate forecasting is prevalent because:

(a) intermittent resources such as wind are inherently variable and difficult to forecast

(b) there are limited requirements on intermittent generators to forecast accurately and there are no regulatory implications for intermittent generators when forecasts and offers are inaccurate

(c) some intermittent generators (particularly those that do not own other generation assets) may have few incentives to forecast accurately as inaccurate forecasting has less impact on their revenue earnt in the spot market.[8]

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

[6] em6 is delivered by EMS – a separate, non-regulated division of Transpower.

[7] The system operator began using a new TESLA load forecasting service on 3 March 2022, which significantly improved demand forecast accuracy (Electricity Authority, Accuracy of Wind and Load Forecasts Information Paper, 17 October 2022).

[8] This is particularly the case for intermittent generators that do not own other generation assets (eg, hydro) and do not have a retail arm.

2.13. One of the objectives of improving the accuracy of intermittent generation forecasts and offers is to improve security of supply. The Authority also has a range of other workstreams underway to address security of supply issues. The ongoing *future security and resilience* work programme is ensuring that appropriate Code requirements for new generating technologies to support power system resilience are in place. The upcoming *potential solutions for peak electricity capacity* issues decision will outline the market incentive work that the Authority intends to undertake to support near-term security of supply.

3. Effects of inaccurate forecasts

Inaccurate forecasts can have adverse effects on the system and on consumers

3.1. The Authority is concerned that inaccurate intermittent generation forecasts and offers affects other participants' ability to make informed consumption and generation decisions in response to forecast price schedules. This has adverse consequences for the electricity system such as:

(a) Risks to security of supply: These risks occur when participants offer too little generation in response to low prices due to over forecasting of intermittent generation. This may also result in higher costs as more expensive generation is called upon at short notice to make up the supply shortfall.

(b) Inefficient use of resources: This occurs when a generator decides to start up a generation unit that is expensive to run (usually thermal units) based on price signals, but is not dispatched due to alternative cheaper generation being available unexpectedly.

(c) Limited benefits of demand-side participation: This could arise if demand-side participants that are exposed to the spot price do not have enough time to reduce their consumption during times of short supply/high demand, or if they reduce consumption unnecessarily if high prices do not materialise.

3.2. The scenarios above can all lead to higher electricity costs for consumers.

3.3. The grid emergency on 9 August 2021 is an extreme example of how inaccurate forecasting of intermittent generation can undermine the reliability of the electricity system.

3.4. By mid-afternoon on that day, the system operator had received almost 500MW of offers from wind generators for the evening peak. However, during the evening peak a maximum of 300MW of wind generation was actually being produced – 200MW less than indicated prior to the event. The unexpected drop in wind meant that some generators did not have sufficient time to start up their thermal units to address the supply shortfall. This was one of a number of contributing factors to the grid emergency, which resulted in the unplanned disconnection of approximately 34,000 customers.[9]

3.5. More generally, inaccurate generation forecasts can result in the need to ramp up new generation quickly to match the supply shortfall (over-forecasting), or not

[9] Ministry of Business, Innovation and Employment (MBIE), Investigation into electricity supply interruptions of 9 August 2021, 2021

dispatch other generation with a higher short-run marginal cost at the last minute, which is costly for owners of these assets (under-forecasting).

Inaccurate forecasting impacts spot prices

3.6. We are already seeing implications of inaccurate forecasting on the system in the form of increasing volatility between final and pre-dispatch pricing.[10]

3.7. As part of the issues and options paper, EY undertook an analysis to determine the impact that inaccurate wind generation forecasts have had on electricity system costs. EY looked at the impacts of:

(a) under-forecasting of wind (when the actual amount generated is greater than the forecast amount)

(b) over-forecasting of wind (when the actual amount generated is less than the forecast amount).

3.8. 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% 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. These costs are generally borne by thermal generators that have chosen to run their plant but are not dispatched. This impacts consumers in the long term as thermal generators seek to recover their costs in future trading periods.

(b) over forecasting of wind, which occurred 67.5% 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. This results in a disbenefit to consumers as expensive back up generation may be required to make up the shortfall.

(c) suppress thermal offers during high demand periods.

3.9. The Authority also calculated that:

(a) the estimated deadweight loss[11] due to the price impact of wind forecast error is approximately $960,000 per annum

(b) the productive efficiency costs[12] due to the price impact of wind forecast error is approximately $2.2 million per annum.

Adverse consequences of inaccurate forecasts and offers are likely to increase as the proportion of intermittent generation increases

3.10. The share of supply from intermittent sources of generation in New Zealand is growing rapidly. Between 2020 and 2023, installed wind capacity increased by 44% from 885MW to 1,280MW and is now approximately 12% of total installed capacity.[13] There is a large pipeline of wind and solar projects being actively pursued and it is expected that by 2050 the share of supply from intermittent

[10] https://www.ea.govt.nz/news/eye-on-electricity/past-and-future-spot-market-volatility/

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

[12] 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.

[13] https://www.ea.govt.nz/news/eye-on-electricity/past-and-future-spot-market-volatility/

sources will increase to around 50%.[14] This includes the possibility of offshore wind farms, which could be operational in New Zealand in 10–15 years' time.

3.11. As the proportion of intermittent generation expands, forecasting inaccuracies will create a growing challenge for system stability and efficiency. There is also the potential for the economic impacts of inaccurate forecasting to worsen. Improving the accuracy of intermittent generation forecasts and offers are a key building block to ensuring intermittent generation makes the best possible contribution to a renewables-based electricity system that delivers sustainable, reliable and affordable electricity to consumers.

3.12. In the Authority's Market Development Advisory Group's recent report *Price discovery in a renewables-based electricity system*, it recommended better forecasting of intermittent generation was needed.[15]

4. The Authority has sought feedback on this policy matter

The Authority has analysed submissions and has identified its preferred option to improve forecasting of intermittent generation

4.1. In June 2023, the Authority published an issues and options paper that sought feedback on options to improve the accuracy of intermittent generation forecasts.

4.2. The Authority received 13 submissions. Submitters included current intermittent generators, generator retailers, Transpower, and intermittent generators in the process of entering, or looking to enter, the New Zealand electricity market in the near future. A full list of submitters is included in Appendix A.

4.3. The submissions are published on the Authority's website. A summary of submitters' responses to the consultation questions is listed in Appendix B.

4.4. Following analysis of submissions, the Authority has identified its preferred option to improve forecasting of intermittent generation. This preferred option and the analysis that informed it are discussed below.

The Authority considered four options to improve the accuracy of forecasts and offers

4.5. The Authority's objective is to improve the accuracy of forecasts and offers so that price signals are accurate and clear, and risks to security of supply and the inefficient use of resources are minimised.

4.6. Improved generation forecasts are a key building block to strengthen the performance of a renewables-based electricity system.

4.7. Forecasting arrangements fall into the following groups:

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

[15] See recommendation 1 – '*Improve short-term forecasts of wind, solar and demand*'.

(a) Decentralised arrangements where intermittent generators are individually responsible for their own forecasts (ie, both price and quantity elements). This arrangement is currently used in New Zealand.

(b) Centralised arrangements where a service provider is responsible for forecasting the likely intermittent generation quantities available for most intermittent generators across the country (with extensive data inputs provided by generators). This arrangement is used in many other jurisdictions.

4.8. As part of the issues and options paper, Concept Consulting reviewed the intermittent generation forecasting arrangements in other jurisdictions. Concept looked at five overseas jurisdictions – Alberta, Australia, Texas, Ireland and Great Britain. Concept also investigated the forecasting arrangements in European Union member states.[16]

4.9. The Authority considered experience from overseas jurisdictions – in particular the National Electricity Market in Australia, Alberta, Texas which use an ‘energy-only’ design[17] for their wholesale market.

4.10. In the issues and options paper, the Authority provided a summary of the advantages and disadvantages of each of the four forecasting arrangements being considered:

1) Decentralised forecasting arrangement with incentives/standards.

2) Centralised forecasting arrangement.

3) Hybrid forecasting arrangement (provides a centrally procured forecast of intermittent generation, with the ability for generators to submit offers based on their own forecast if their own forecast is consistently at least as accurate as the centralised forecast).

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

4.11. We assessed each of these options against a set of evaluation criteria. Following feedback from submitters, we simplified and refined the criteria. This is summarised in Table 1.

[16] Concept Consulting, Intermittent generation forecasting arrangements – review of international jurisdictions, 26 January 2023

[17] 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.

Table 1: List of refined evaluation criteria

Evaluation criterion	Description
Efficiency	Includes incentives that will drive better performance and mitigates the risks of under or over forecasting occurring.
Reliability	Is resilient and fit-for-purpose under a renewables-based generation system and mitigate risks to security of supply.
Enhances competition	Helps to ensure there are accurate price signals, the cost of forecasting and the cost of providing the timely updating of market offers does not act as a barrier to entry, and the arrangement enables innovation.
Affordability	The required benefits are balanced and considered against the costs (including implementation and compliance costs).
Practicability	The forecasting arrangement is workable and there is a low risk that barriers will impede implementation.

4.12. Based on the Authority's assessment of each option against the refined evaluation criteria, the hybrid forecasting arrangement scored the highest. The centralised arrangement scored the second highest. The status quo scored the lowest.

4.13. Table 2 shows the summary of the Authority's assessment of each option against the refined evaluation criteria. More detail about the Authority's assessment is outlined in Appendix C.

Table 2: Summary of the Authority's assessment of each option against the evaluation criteria

Evaluation criteria → **Options ↓**	Efficiency	Reliability	Enhances competition	Affordability	Practicability	**Overall assessment**
Status quo	Medium (2)	Low (1)	Medium (2)	Medium (2)	Low (1)	**8**
Decentralised arrangement with incentives/ standards	Medium (2)	Medium (2)	Medium (2)	Medium (2)	Medium (2)	**10**
Centralised arrangement	Medium (2)	High (3)	Medium (2)	High (3)	High (3)	**13**
Centralised arrangement with option for self-forecasting (hybrid)	High (3)	High (3)	High (3)	High (3)	High (3)	**15**
Ahead and balancing market	Medium (2)	High (3)	Medium (2)	Low (1)	Medium (2)	**10**

Key:
- High = 3 points
- Medium = 2 points
- Low = 1 point

5. Our preferred option

The preferred option is a hybrid forecasting arrangement

5.1. In the issues and options paper, the Authority's view was that all four forecasting arrangements considered would be an improvement on the status quo.

5.2. Following the assessment of each option against the refined evaluation criteria and taking into account submitters' feedback, the Authority has decided to implement a hybrid forecasting arrangement. A hybrid arrangement provides a centrally procured forecast of intermittent generation, with the ability for generators to submit offers based on their own forecast if they meet the prescribed accuracy standards. This would require their own forecast to be consistently at least as accurate as the centralised forecast.

5.3. This option supports the development of a market for generation forecasting and foster innovation through creating competitive tension between the centralised forecaster and other providers.

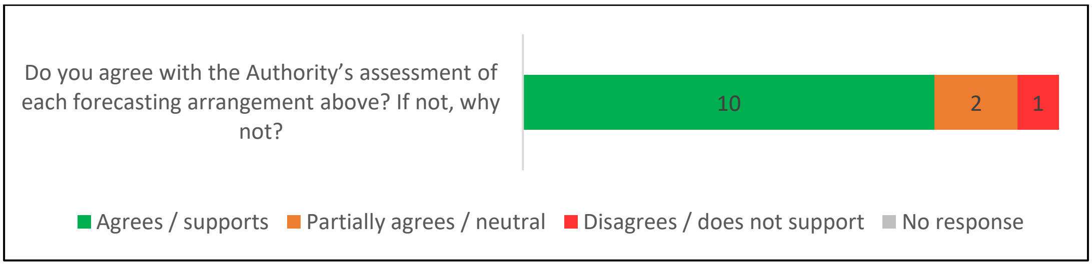
5.4. Innovator-developers will benefit from this initiative which will support competition by reducing regulatory and information barriers to participation by new entrants. We also expect this measure will improve affordability for consumers as better forecasts will increase the accuracy of price signals, which contributes to the most efficient and lowest cost sources of generation being dispatched.

5.5. A hybrid arrangement also has the potential to create competitive tension between centralised forecasting and self-forecasting approaches, which could improve the quality of both approaches. Some generators have also invested heavily in more accurate self-forecasting arrangements.

5.6. We acknowledge that this option will add some additional costs to participants, but on balance no more than the fully centralised forecasting option because many intermittent generators will continue to procure and use their own weather forecasts for a range of purposes. This might include inflows into lakes and tributaries, temperatures and wind speeds for site safety and maintenance planning schedules.

5.7. Moreover, we believe the hybrid arrangement will also reduce overall system costs by increasing forecast accuracy by ensuring better forecast data is available to all intermittent generators.

5.8. This option was supported by majority of submitters, including Mercury, Meridian, Transpower, Helios Energy, ETSI, Lodestone and NewPower. Other submitters indicated a preference for a centralised forecasting arrangement (but not specifically the hybrid option). One submitter (Nova) disagreed with the Authority's assessment, citing that in its view the hybrid option is likely to lead to duplication and excessive pass-through expenses for those parties that rely on the central forecasts.



5.9. The Authority commissioned Concept Consulting to undertake a cost-benefit analysis to determine the net benefits of shifting to a hybrid arrangement.

5.10. Concept estimated minimum benefits of $15.4m over five years ($3.1m per year) are available from moving to a hybrid arrangement and adopting forecast quality standards.[18]

5.11. Concept derived this estimate by comparing relative performance of currently available ‘distributed’ and ‘central’ forecasts. Annual benefits, which increase as wind generation grows, accrue principally from reducing:

(a) material or major over-forecasting events

(b) major under-forecasting events

(c) systematic bias in wind generation offers towards over-forecasting.

5.12. Concept assessed the five-year net present value of implementing the Authority’s proposal as in a range from $15.4m to $33.9m. The 15-year net present value is assessed as in a range from $151.5m to $326.5m. This reflects that the proportion of intermittent generation in 15 years is expected to be considerably higher than it is today.

5.13. The table below set out the economic benefits for a base case as well as several sensitivity cases.

Scenario	**Economic benefits (5-year net present value)**
Base case	$30.7m
Forecasts adjusted for bias (Removing the slight over-forecasting bias that, on average, applies to forecasts and offers today)	$21.0m
Cheaper flexible generation preparation costs (Assuming that the costs of using flexible generation reduces over time)	$32.8m
Slower growth in wind generation capacity (Assuming a 25% slower growth that what current modelling suggests)	$21.7m
Higher de-rating factor (Applying a 75% de-rating factor rather than a de-rating factor of 50% for the base case)	$15.4m
Closer decision point (Assuming flexible generators can make generation/consumption decisions 6 hours ahead of real time rather than 12 hours ahead for the base case)	$33.9m

5.14. The cost-benefit analysis report is included in Appendix D.

[18] The net present values in the cost-benefit analysis are discounted based on a 5% discount rate. The per year figures are the annual average of the discounted net present value figures. The annual average of the non-discounted benefits would be higher.

6. Key design features

6.1. This section describes the preferred option in more detail, including issues such as:

(a) who the new forecasting arrangement will apply to

(b) who will be responsible for submitting bids and offers to the system operator (using WITS)

(c) who will be required to contribute to the costs of the centralised forecast

(d) how accuracy standards and process requirements will be applied

(e) the process intermittent generators must follow if they wish to transition from using the centralised forecast to using their own

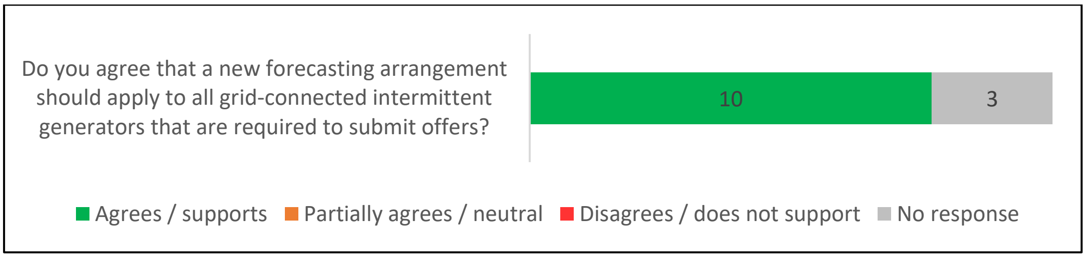
(f) the process for transitioning to the new arrangement.

6.2. This section also summarises submitters' responses to questions raised in the issues and options paper. More detailed comments made by submitters are set out in Appendix B.

6.3. Some of the policy design questions in this section were not explicitly raised in the issues and options paper, but they relate closely to the consultation questions. We have indicated which questions were raised in the issues and options paper.

The new forecasting arrangement will apply to all intermittent generators that are required to submit offers by the system operator *(relates to Q2 of consultation paper)*

6.4. This decision is consistent with the views of all submitters who responded to this question.



6.5. The new forecasting arrangements will apply to current forms of intermittent generation in New Zealand (wind and solar) as well as forms of intermittent generation that do not yet exist in New Zealand but may be built in the future (eg, tidal and offshore wind).

6.6. The new forecasting arrangements will also apply to embedded or distribution-connected intermittent generators that are required to submit offers. It is important that embedded or distribution-connected generators' offers (and forecasts) are captured given they still contribute to the country's overall electricity demand. Cumulatively, there is more than 300MW of embedded wind generation comprising more than 30MW plants including Te Uku, West Wind and White Hill.

6.7. The new arrangements will not apply to behind-the-meter resources because these resources typically have low generation capacity and generate electricity primarily for individual purposes.

6.8. The Authority appreciated Mercury's suggestion that the arrangements may need to reflect the inherent differences between wind and solar generation (eg, the current wording in the Code for persistence forecasting may not be suitable for solar generation). The current wording in the Code for resource persistence forecasting will be amended to reflect the new arrangements. This is discussed in more detail in paragraphs 6.64–6.69.

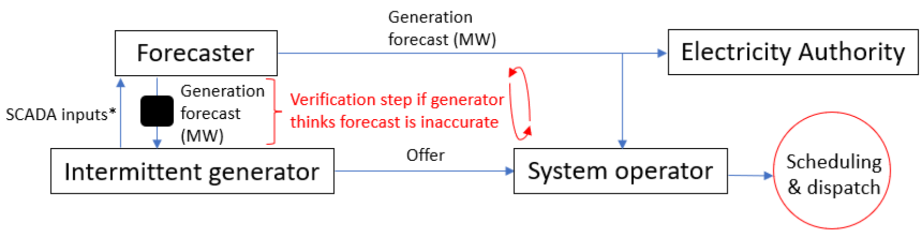
6.9. ETSI suggested allowing sufficient time for existing assets to comply with new arrangements and the use of a sunset clause to ensure compliance by a given date. The Authority agrees with this suggestion and will give intermittent generators a period of time to adjust to the new requirements and a deadline of when this must be done by. More information about the transition period is outlined in paragraphs 6.77–6.79.

Intermittent generators will continue to have full legal responsibility for their offers to the system operator via WITS *(relates to Q17 of consultation paper)*

6.10. The Authority considers that intermittent generators should remain responsible for their generation offers as they are best placed to take into account any operational data (eg, future plant limitations and/or outages) that may not be reflected in the forecast they receive.

6.11. The centralised forecaster will be responsible for providing intermittent generators with generation forecasts. Intermittent generators may be required to provide the centralised forecaster with site-specific data[19] to enable the service provider to produce generation forecasts. Figure 2 illustrates the intended forecasting and dispatch process.

Figure 2: Simplified forecasting and dispatch process



* SCADA inputs include actual generation output, wind speed/irradiance, number of turbines/inverters available, and turbines in high wind cut-out

Consideration of whether the centralised forecaster could submit offers on behalf of generators

6.12. The Authority recognises that requiring generators to submit generation offers (on a 24/7 basis) could act as a barrier to entry to smaller, less well-resourced intermittent generators.

6.13. The Authority has considered whether the centralised forecaster could submit FOGP as well as priced tranches of volume offers on behalf of generators to address the concern about regulatory barriers to entry.

6.14. If the centralised forecaster was able to submit offers on generators' behalf, the generator would need to confirm with the forecaster the price <u>and</u> quantity of

[19] For example, the precise locations and heights of turbines and meteorological towers, type and model of turbines, manufacturers' power curves and date of operations.

generation it is willing to offer across all relevant trading periods (ie, the price and quantity elements cannot be separated). Under this approach, generators would still remain legally responsible for their obligations under the Code. The majority of intermittent generators are currently price takers and have offered their generation into the market at a $0.01/MWh.

6.15. As part of the procurement process for a centralised forecaster, the Authority will seek information from the market about forecasters' ability to submit offers on generators' behalf (on a commercial basis) and the estimated cost the centralised forecaster would charge the intermittent forecaster for providing this service.

The centralised forecaster will be required to provide a generation forecast to intermittent generators (a MW value) rather than a resource forecast (a m/s or W/m^2 value)

6.16. Most forecasters will have the ability to produce generation forecasts and it makes sense to take advantage of this compared to producing a resource forecast (which generators would then need to convert into a generation forecast/offer). It will also be easier to apply accuracy standards and to monitor a generation forecast.

6.17. As part of the procurement process for a centralised forecaster, the Authority will need to determine what inputs a forecaster would need to produce accurate generation forecasts (eg, determining if individual solar panel/array and/or wind turbine outages were required). We will also engage with generators to determine whether they would require more information in a generation forecast other than a MW value per trading period (eg, a confidence interval).

There may be separate centralised wind and solar forecasts

6.18. There are unique challenges in forecasting both wind and solar. For example, knowing when the sun will rise, set and be at its peak at different times of the day can be easily determined. However, forecasting exactly when a cloud may cause solar irradiance to drop and how long this occurs for is difficult. Likewise, knowing if the general wind trend is going to increase, decrease or stay the same over various timeframes can be relatively easy to predict. However, the exact trading period at which wind speed/direction changes can be more challenging (eg, knowing the exact instance when a cold front will arrive).

6.19. The Authority does not have a preference for whether there should be separate forecasters for wind and solar generation.[20] The Authority will decide this through the procurement process. Some forecasters may be better at forecasting one source of generation more accurately than the other, while some may be equally as capable at forecasting both.

Forecasts will need to be updated more regularly than the current requirements (relates to Q10 of consultation paper)

6.20. If an intermittent generator receives an updated forecast that varies from its previously submitted offers, it will be required to submit a revised offer to reflect the most up to date forecast.

[20] In the future, it may also be necessary to procure centralised forecasts of other forms of intermittent generation, such as tidal.

6.21. Most submitters were supportive of intermittent generation forecasts being updated more regularly, particularly closer to real time, and for offers to reflect the most up-to-date forecasts.

6.22. The frequency at which forecasts are updated will be agreed with the centralised forecaster as part of contract negotiations. This will also be reflected in the requirements that will apply to the self-forecasting regime.

6.23. There is a cost/benefit trade-off between increasing the frequency of forecast updates and what will be useful for participants (ie, more frequent updates would likely cost more). However, the costs of forecasts are decreasing as technology improves.

6.24. Nova suggested that intermittent generators should operate within the same rules as the thermal and hydro generators to update their offers. Clause 13.18 of the Code requires non-intermittent generators to submit a new offer if the total MW specified in their original offer exceeds, by more than 5MW, the total MW they expect to generate at the point of connection to the grid for the trading period.

6.25. Given the uncertainty of wind and solar, the Authority does not consider it to be practicable to expect or require intermittent generators to comply with the offer requirements outlined in clause 13.18 of the Code.

Forecast information will be published on WITS (relates to Q18 of consultation paper)

6.26. Consistent with some submitters' feedback, the Authority has decided that the following information will be published:

(a) Forecasts at the national and island level.

(b) Confidence intervals or the range/uncertainty of an intermittent generation forecast.

6.27. The Authority considered the merits of publishing information at the regional level. However, in some regions there may be very few intermittent generation sites. Therefore, publishing region-specific information could disadvantage owners of these assets. The Authority believes publishing information at the regional level could be done in the future when there is a greater number of intermittent generation assets across the country.

6.28. The Authority thinks this information should be published on a platform that is accessible to all participants and can be viewed alongside other market data, such as pricing and scheduling data. Consistent with some submitters' feedback, the Authority has decided that information must be published on WITS (WITS has an API[21] with other platforms to ensure it shows correct and up to date information). The NZX, as WITS manager, would be responsible for publishing this information.

All generators will be required to contribute to the costs of the centralised forecasts *(relates to Q17 of consultation paper)*

6.29. The Authority considered two options for how a centralised forecast (or multiple forecasts) could be paid for:

[21] An API is a software intermediary that allows two applications to communicate with each other. APIs are an accessible way to extract and share data within and across organisations.

a) Costs are allocated to all intermittent generators that are required to make offers (based on installed capacity). This option follows an ‘exacerbator pays’ principle where the costs of inaccurate forecasts are borne by those whose actions cause the inaccuracies. It also reflects that intermittent generators directly benefit from more accurate forecasts.

b) Costs are apportioned across all generators that are required to make offers. This option follows a ‘beneficiary pays’ principle that reflects that all generators (that are required to make offers) benefit from more accurate intermittent generation forecasts and offers. This is similar to the approach taken in the Australian National Electricity Market.

6.30. While many submitters supported an ‘exacerbator pays’ approach where the costs of the centralised forecast would be allocated to intermittent generators that are required to make offers, the Authority recognises that all generators – not just intermittent generators – will benefit from improved intermittent generation forecasts and offers.

6.31. The Authority is also concerned that allocating costs of the centralised forecast to intermittent generators only could act as a barrier to entry to new intermittent generators entering the market. This would be undesirable, particularly given over the next decade the number of intermittent generators (primarily solar) entering the New Zealand market is expected to increase considerably.

6.32. For these reasons, the Authority has decided to adopt a ‘beneficiary pays’ approach where the costs of the centralised forecast will be apportioned across all generators required to make offers.

6.33. The clearing manager will be responsible for ensuring costs are appropriately allocated to market participants.[22]

6.34. Under this approach, intermittent generators will contribute to the costs of, and receive, the centralised forecast regardless of whether they base their offers on a self-forecast or the centralised forecast.

Forecast performance standards, process requirements and/or generation accuracy standards will apply (relates to Q11 and Q14 of consultation paper)

Forecast performance standards will apply to the centralised forecaster

6.35. Forecast performance standards in the form of outcome standards[23] will apply to the centralised forecaster. This is preferred to process standards[24] because outcome standards make it clear what the required performance/accuracy is, but still enables the forecaster to discover ways to achieve the standards.

6.36. These standards would be based on the difference between forecast generation and actual generation (presuming the generator bases its generation offers on the generation forecast provided by the centralised forecaster). A centralised forecaster

[22] The clearing manager ensures that industry participants pay or are paid the correct amount for the electricity they generate, or consume, and for market-related costs. The Authority has contracted the NZX as the clearing manager.

[23] An example of an outcome standard is specifying an accuracy threshold that must be met.

[24] Process standards specify a process that intermittent generators/centralised forecasters must follow. An example of a process standard is specifying a forecasting method that must be used.

will not be held responsible for not meeting a forecast performance standard if this is due to a planned or unexpected outage they were not made aware of.

6.37. Forecast performance standards would be negotiated as part of contract negotiations and every time the contract is revised. The standards will be informed by analysis undertaken by the Authority alongside evidence from the forecaster.

Generation accuracy standards will apply to generators basing their offers on a self-forecast

6.38. Generators basing their offers on a self-forecast will be required to meet generation accuracy standards. The standards will reflect the forecast performance standards that apply to the centralised forecaster. The application of generation accuracy standards will ensure that generators' self-forecasts are consistently at least as accurate as the centralised forecast.

Process requirements would apply to generators required to use the centralised forecast and generators that have been given permission to base their offers on their own forecast

Generators basing offers on the centralised forecast

6.39. Generators required to use the centralised forecast must base their generation offers on the centralised forecast unless a generator has a bona fide physical reason[25] for not doing so or is aware of a planned outage that is not reflected in the centralised forecast.

6.40. If a generator's offer does not reflect the centralised forecast, it must notify the system operator.

Generators basing offers on a self-forecast

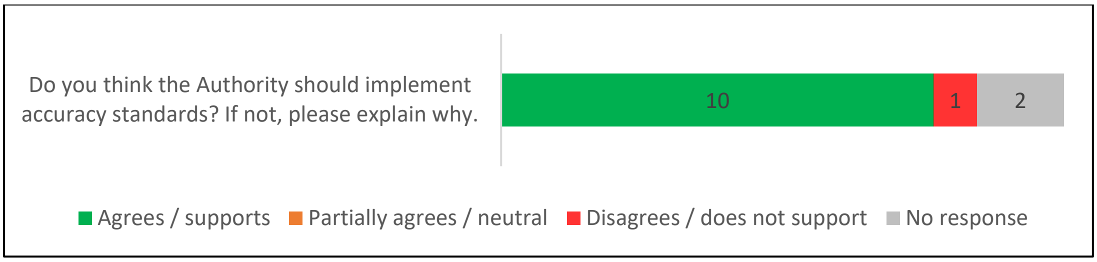
6.41. Generators that have been given permission to base their offers on a self-forecast must ensure their generation forecasts are consistently at least as accurate as the centralised forecast. This would be assessed on a regular basis by the system operator or the Authority.

6.42. If a generator's forecast is not as accurate as the centralised forecast, it will be required to revert back to basing its offers on the centralised forecast.

Submitters' views

6.43. The Authority's decision to introduce forecast performance standards, process requirements and generation accuracy standards is consistent with most submitters' views. The exception was Mercury, who did not think it would be appropriate to implement accuracy standards because every intermittent generation site differs with different sensitivities. The Authority has accounted for this through the design of the process generators must follow to be permitted to base their offers on a self-forecast. Intermittent generators that are seeking permission to base their offers on a self-forecast must demonstrate that their self-forecast is consistently at least as accurate as the centralised forecast for a given site.

[25] Bona fide physical reasons are defined in the Code and includes circumstances such as a reasonably unforeseeable change in generation capability.



If an intermittent generator fails to comply with the Code requirements, the Authority may take action for a breach of the Code (relates to Q14 and Q15 of consultation paper)

6.44. The policy objective is to ensure that intermittent generators' offers are as accurate as possible during all trading periods. The Authority will monitor the centralised forecasts and intermittent generators' offers to ensure intermittent generators are appropriately using the forecast information to inform their offers (noting that generators are not required to offer all capacity into the market).

6.45. Supported by quality data monitoring, the Authority may be able to enforce a breach during any trading period.

6.46. The Authority will maintain discretion about when to take action in the event of a breach in accordance with its Compliance Strategy. Inaccurate forecasts/offers coinciding with low residual situations generally lead to higher system costs, which could be taken into account when deciding whether to take action against non-compliance.

The Authority is undertaking analysis to support the development of forecast performance standards

6.47. The Authority thinks forecast performance accuracy standards could be based on the accuracy of the best forecaster in each resource. The following would be taken into account when determining the forecast performance standards:

(a) The wind forecast the system operator currently procures for its internal security assessment processes.

(b) The level of accuracy a forecaster thinks it could meet across different timeframes.

(c) Analysis undertaken by the Authority on historical accuracy and the impacts of improving accuracy.

6.48. The Authority is analysing forecast performance 2, 6 and 12 hours before real time for the five main wind generators in New Zealand[26] between 1 January 2021 and 10 October 2023.

6.49. The Authority is also carrying out 'what-if' scenarios aiming to understand the potential impact of lower wind forecast inaccuracies.

6.50. The purpose of this analysis is to determine:

(a) what forecast accuracy is possible based on the most accurate forecasts 2, 6 and 12 hours before real time

[26] Mercury, New Zealand Wind Farms, Meridian, Genesis and Manawa.

(b) how frequently forecast inaccuracies occurred (using different thresholds[27])

(c) how much of the impact of reducing forecast inaccuracies occurred during trading periods with low residuals. This could inform whether we could restrict accuracy standards (or have stricter accuracy standards) during those trading periods only.

6.51. Previous analysis carried out by the Authority has found that, as expected, most wind generators' 2-hour ahead forecasts were generally more accurate than their 6-hour and 12-hour ahead forecasts.[28] This analysis is being updated and expanded to inform accuracy standards at different timeframes.

6.52. The analysis is also looking at whether the majority of impacts from inaccurate wind forecasts occur during trading periods with low residuals. If so, compliance with accuracy standards could be restricted to these times only, or more stringent accuracy standards could apply to these times.

6.53. The Authority's full analysis will be published on the Authority's website.

There may be multiple forecast performance standards across different timeframes, with performance/accuracy obligations becoming more stringent closer to real time (relates to Q12 of consultation paper)

6.54. This approach reflects that the ability to accurately forecast wind and solar typically improves the closer you get to real time. This also places incentives on the forecaster to continually improve its forecasts and for generators to ensure their offers reflect the latest forecast. Analysis of historical data will help inform accuracy standards at different timeframes.

Forecast performance standards will be based on a certain percentage of FOGP, available capacity, or a certain number of MW (relates to Q12 of consultation paper)

6.55. Depending on the size of the wind/solar farm and its FOGP, either a MW-based standard or percentage-based standard may be more appropriate.

6.56. For example, a forecast performance standard could be *'12 hours before real time, 90% of the time over a four-week period, forecast accuracy must be the greater of 10MW, or within 20%, of the FOGP specified in the generator's final offer'*. For a 50MW wind farm that has a final FOGP of 40MW, 20% would equal 8MW. Given this is lower than 10MW, the 10MW standard would apply.

6.57. The Authority considered whether forecast performance standards should be based on the percentage of available capacity or on the percentage of FOGP, as suggested by Nova. Compared to a standard based on a FOGP, a standard based on the percentage of available capacity would mean that a higher error variation

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[27] The Authority derived a theoretical 20% threshold relative to adjusted capacity (based on the best performing wind farm operator) to assess accuracy (adjusted capacity is nominal capacity minus outages). Deriving a percentage-based threshold rather than the current 30MW threshold reflects that a MW-based threshold is often harder to achieve for larger wind farms. For example, if a windfarm with 200MW of nominal capacity had 20MW of outages, its adjusted capacity would be 180MW. The 20% threshold that would apply to this wind farm would be 36MW. The 20% threshold for a smaller windfarm with 50MW of adjusted capacity would be 10MW.

[28] This was observed for NZ Wind Farms, Meridian and Mercury's forecasts for the power purchase agreements they have with Manawa and Genesis (Electricity Authority, Accuracy of Wind and Load Forecasts Information Paper, 17 October 2022).

would be permitted.[29] The Authority's analysis will inform the decision on whether using the more stringent accuracy standard is needed.

6.58. The Authority recognises that for various reasons (such as a wind/solar farm's proximity to measuring sites, proximity to other wind/solar farms, altitude and local topography) some sites in New Zealand will be more difficult to forecast than others.

6.59. Localised forecasting challenges will be taken into account when performance standards are negotiated with the centralised forecaster.

Generation accuracy standards would not apply if intermittent generators are constrained off by the system operator

6.60. If a forecast performance standard is not met due to being constrained off by the system operator, the Authority would disregard these trading periods for the purposes of monitoring except if actual generation was higher or lower than the constrained off dispatch level.

Resource persistence forecasting will not be disallowed *(relates to Q13 of consultation paper)*

6.61. Some reports following the 9 August 2021 grid emergency recommended that the Authority amend the Code to disallow persistence forecasting.[30]

6.62. The Authority's assessment of trading periods between April 2021 and March 2022 showed that improvements in forecast accuracy generally aligned with when intermittent generators start submitting resource persistence forecasts. Despite this, the Authority recognises that in some situations, persistence forecasting can lead to inaccurate offers (for example, when there is an increasing or declining wind trend).[31] Persistence forecasting can also be inaccurate for solar, particularly at the start and end of each day.

6.63. The Authority is not convinced that there is a strong case for prohibiting intermittent generators from using persistence forecasting or prescribing exactly when they can and cannot use this method. However, under a centralised forecasting arrangement, persistence forecasting may not need to be used because other short-term forecasting methods may be preferred by a centralised forecaster (or persistence forecasting is just one of several factors of a short-term forecast).

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[29] For example, if an intermittent generator has an installed capacity of 200MW, but has 100MW of planned outages, it will have 100MW of available capacity. If the centralised forecaster predicts that 50MW of generation will be available in a particular trading period, with an accuracy standard based on +/- 20% of available capacity, there would be a 20MW margin of error. However, with an accuracy standard that is based on +/- 20% of forecast generation, there would only be a 10MW margin of error.

[30] The Authority, the Ministry of Business, Innovation and Employment, and Transpower all carried out separate reviews:

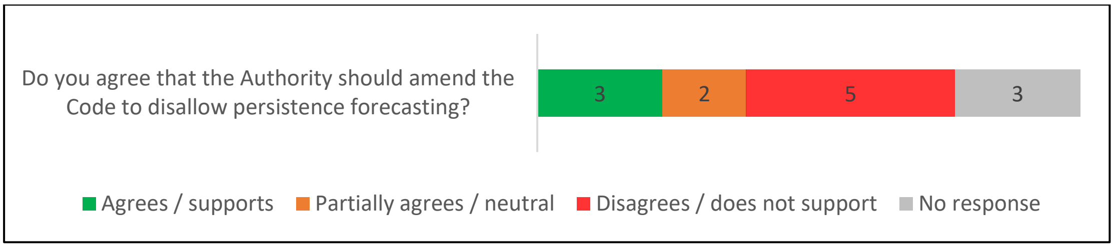
- Electricity Authority, Immediate assurance review of the 9 August 2021 demand management event – Review of the system operator's tools, processes and communications around the event, 10 September 2021
- Ministry of Business, Innovation and Employment (MBIE), Investigation into electricity supply interruptions of 9 August 2021, 2021
- Transpower, Independent Investigation of the 9 August 2021 Grid Emergency, 6 October 2021

[31] Refer to page 2 of Transpower's 11 February 2024 Weekly Market Movements publication: https://static.transpower.co.nz/public/bulk-upload/documents/Market%20Operations%20-%20Weekly%20Market%20Movements%20-%2011%20February%202024.pdf

6.64. The Authority has decided to be 'process neutral' and not specify the methods and the hours before real time that a forecaster should use a particular forecasting method. When appropriate forecast performance standards are in place, the forecaster and generators will be incentivised to ensure forecasts and offers are as accurate as possible using methods they deem to be most practical. This approach would also incentivise the forecaster to continually improve its forecasting methods and capabilities.

6.65. As part of the Code amendment process to give effect to the decisions outlined in this paper, the current section in the Code that pertains to resource persistence forecasting will be amended.[32]

6.66. Submitters had mixed views on this matter. However, there was slightly more support from submitters to retain the ability for intermittent generators to use persistence forecasting than there was to disallowing it (Meridian, Lodestone, NewPower, Nova and Genesis did not agree that the Authority should disallow persistence forecasting).



There will be prescribed requirements that intermittent generators must meet if they wish to transition from using the centralised forecast to using their own

6.67. If a generator wants to base its offers on a self-forecast rather than the centralised forecast, it must show the Authority that its offers based on its self-forecast are accurate enough. This could be done by:

a) comparing forecasts – eg, the generator displaying its forecast alongside the centralised forecast for a specified period of time; or

b) comparing offers – eg, the generator submitting 'mock' offers to the Authority based on its self-forecast for a period of time (alongside its real offers based on the centralised forecast).

6.68. The Authority has decided the latter option will apply. This is preferred because the accuracy of generators' offers is ultimately what matters. This would also enable the generator to account for last-minute outage information in its offers, which may not be reflected in the forecast it receives.

6.69. A generator wanting to base its offers on a self-forecast must submit mock offers to the Authority based on the self-forecast for each generation site for a period of at

[32] Refer to clauses 13.18A(1), (2) and (3) of the Code.

least four weeks. A longer period may be required to cover a range of weather conditions.[33]

6.70. The Authority would be responsible for agreeing that a generator can base its offers on a self-forecast if it is satisfied that that its four weeks' worth of mock offers are sufficiently accurate. The Authority's decision will be based on whether the generator's mock offers are consistently at least as accurate as offers based on the centralised forecast.

6.71. If a generator wishes to change self-forecast providers or introduce new forecasting models, it must complete the steps above and resubmit an application form to the Authority.

6.72. Generators that are basing their offers on a self-forecast should continually monitor the quality of their forecast. If they determine their self-forecast to be inaccurate, they should use the centralised forecast for the relevant trading periods.

6.73. The Authority will also monitor the accuracy of generation offers based on generators' self-forecasts. If the Authority determines that a generator's self-forecast is not accurate enough, it will inform the generator that it must base its offers on the centralised forecast until the generator can demonstrate its self-forecast is accurate enough.

Intermittent generators will be given a three-month period to transition to the new arrangement and comply with the associated requirements

6.74. Given a centralised arrangement would be a shift from the status quo, it would be prudent to give a forecaster and generators sufficient time for existing assets to comply with new arrangements.

6.75. The Authority has decided that the centralised forecast will be provided to intermittent generators for three months before its use is mandated. This will be a trial period and will give intermittent generators time to adjust to the new arrangement.

6.76. After the three-month period, based on mock offers/historical performance data, the Authority would determine which generators will be able to base their offers on a self-forecast. Generators that have not applied to base their offers on a self-forecast, or whose self-forecast has not been shown to be accurate enough, will be obligated to ensure their generation offers reflect the centralised forecast.

[33] In the Australian National Electricity Market, the Australian Energy Market Operator assesses ongoing performance on a weekly basis (based on rolling one, four and eight full week assessment windows) to verify that a generator's self-forecast is no worse than the centralised forecasts over at least one of the assessment windows. The short assessment window (one week) allows the self-forecast performance to reflect more recent, potentially large self-forecast model improvements, while the medium and long assessment windows (four and eight weeks) capture the impact on self-forecast performance of a greater diversity of weather conditions and reduce the risk that self-forecasts are not assessed for constrained off generating units.

7. The Authority will implement other complementary measures to improve forecasting performance

Educational approach to the interpretation of resource persistence forecasting and FOGP provisions in the Code

7.1. In 2019, the provisions in the Code relating to resource persistence forecasting/FOGP were amended to ensure intermittent generators' offers reflect a FOGP rather than what the wind/solar farm is currently generating.

7.2. While the provisions in the Code relating to resource persistence forecasting/FOGP will be amended to give effect to a new forecasting arrangement, in the meantime it is important that intermittent generators are correctly interpreting and giving effect to the current Code provisions that relate to resource persistence forecasting/FOGP.

7.3. The Authority has published guidance to provide clarity to intermittent generators on how the provisions in the Code relating to resource persistence forecasting/FOGP should be interpreted. We have also reiterated our expectation that intermittent generators comply with these requirements.

Publishing performance data of intermittent generators' offers vs actual generation

7.4. The Authority will work towards the new provisions being in place in time for winter 2025.

7.5. The Authority will shortly begin publishing forecast accuracy for each intermittent generator and generation site across different timeframes (on a monthly scale). This will improve transparency of the difference between intermittent generation forecasts of generation potential and actual generation. It will also form the basis for decisions about who will be eligible to base their offers on a self-forecast under the new forecasting arrangement.

8. Risks associated with the hybrid arrangement

The centralised forecast could be inaccurate

8.1. There is a risk that if a centralised forecast is consistently inaccurate, it could have wider system impacts given many intermittent generators will likely be relying on it to inform their offers.

8.2. This risk will be mitigated by putting in place the centralised forecast for three months before its use is mandated. This trial period will give intermittent generators time to adjust to the new arrangement.

8.3. By allowing intermittent generators to self-forecast, this is likely to incentivise the centralised forecaster to continually improve its forecasting capabilities.

There may be specific trading periods where a generator's own forecast is more accurate than the centralised forecast (but they are not yet eligible to base their offer on a self-forecast)

8.4. There is a risk that a generator may claim the requirement to base their offer on the centralised forecast caused their offer to be less accurate, which could have financial implications for them.

8.5. The policy objective is to ensure that intermittent generators' offers are as accurate as possible during all trading periods (ie, consistently accurate over the long term). If an alternative forecast can be shown to be consistently at least as accurate as the centralised forecast, a generator will be permitted to use this forecast to base its offers on. This is why the Authority's decision whether to allow a generator to base its offers on a self-forecast will be based on four weeks' worth of mock offers rather than on a few select trading periods.

8.6. Allowing generators (that have not been given permission to base their offers on a self-forecast) to use a different forecast during certain trading periods would also add complexity to the forecasting arrangement. This would be undesirable.

Intermittent generators may be reluctant to provide the centralised forecaster with commercially sensitive information about the performance of their generation assets

8.7. To develop a centralised forecast, intermittent generators will be required to provide the centralised forecaster with detailed information about their generation assets. Some generators may be concerned about the risks to their commercially sensitive information.

8.8. This risk will be addressed through the contractual process with the Authority and/or a third party, including the requirement for non-disclosure agreements to apply.

Intermittent generators might not use the centralised forecast when they are required to

8.9. Intermittent generators that have not been given permission to base their offers on a self-forecast will be able to continue their current contracts (ie, the Authority would not explicitly prohibit this). However, generators that have not been given permission to base their offers on a self-forecast will be expected to ensure the centralised forecast is used to inform their offers. Generators will also be required to follow prescribed process requirements for submitting offers.

8.10. This risk will also be mitigated by enabling generators that are required to base their offers on the centralised forecast to vary their offer if they have a valid reason for doing so. Generators will be required to notify the system operator in these instances.

Technical issues could disrupt the flow of information between the centralised forecaster and a generator

8.11. This could affect the forecaster's ability to provide generation forecasts because it would lack information about current conditions at the relevant site, actual generation output, numbers of turbines/inverters available etc.

8.12. Being able to establish a communication system with a generator would be a key criteria/requirement for a forecaster to become a centralised forecaster. The communication system could incorporate up to date information about plant outages. If a generator is not able to provide outage information to the forecaster, the generator will be required to account for outages when using the generation forecast to submit offers.

8.13. The risk of a communication system becoming dysfunctional once established will be mitigated as some forecasters have the ability to relatively accurately determine the weather conditions at a particular location despite a weather station not being present at that location. This is done by observing weather data at nearby weather stations and using this data to predict the conditions at the location of interest. The ability to do this could be useful if there are issues with the communication system between the generator and the forecaster.

8.14. Forecasters and generators will also be able to use persistence-based forecasting as a last resort if there are issues with the communication system.

Requiring all generators (required to make offers) to contribute to the costs of the centralised forecast could act as a barrier to entry into the market for new participants

8.15. Requiring all generators to contribute to the costs of the centralised forecast reflects that all generators will benefit from more accurate intermittent generation forecasts and offers. These costs are not expected to be significant relative to intermittent generators' operational costs.

8.16. The alternative would have been to allocate costs of the centralised forecast to intermittent generators only (or only to those intermittent generators required to use the centralised forecast). This would have acted as a greater barrier to entry to new intermittent generators entering the market, as there would be fewer parties to apportion the costs over.

Regulatory burden arising from requiring generators to submit offers to the system operator on a 24/7 basis

8.17. The Authority recognises that requiring generators to submit offers could act as a barrier to entry to smaller, less well-resourced intermittent generators.

8.18. We will address this risk by including the provision of a service to submit offers within the procurement process for a centralised forecaster. We will also ask respondents to provide separate costings for the provision of this service as these costs are additional to the cost of the centralised forecast.

9. Monitoring and evaluating the impact of the changes

Monitoring

9.1. Ongoing monitoring arrangements will be established to oversee both forecaster and generator performance.

9.2. As noted previously, the Authority will publish intermittent generators' offers vs actual generation. This will enable interested parties to monitor the accuracy of intermittent generators’ forecasts/offers in the interim period before the forecasting arrangement becomes operational.

Evaluation and review

9.3. The Authority will review the policy changes after the initial contract term with the centralised forecaster has ended.[34] The Authority will determine whether the transition to a hybrid arrangement has helped to achieve the policy objective and remains fit-for-purpose.

9.4. As part of this review, the Authority will also consider the following:

- Is there still a problem (and is it the one originally identified)? – ie, are intermittent generation forecasts still causing avoidable risks to security of supply, leading to the inefficient use of resources, and impacting other participants’ generation and consumption decisions?
- Are the policy objectives being met? – ie, has there been a material improvement in the accuracy of intermittent generation forecasts/offers?
- Are the impacts as expected? Are there any unforeseen problems? Are there any indirect effects that were not anticipated?
- Is intervention still required? Is the centralised forecasting arrangement and other policy changes still the most appropriate, or would another arrangement/other policy interventions be more suitable?

10. Implementation timeframes and next steps

10.1. The Authority will work towards the new provisions being in place in time for winter 2025. This will involve the following:

(a) The Authority will prepare the required Code amendments to give effect to the decisions outlined in the decision paper.

(b) The Authority (or a third party, with input from the Authority) will undertake a two-stage procurement process to select a service provider to provide a centralised forecasting service in New Zealand.

(c) The new arrangement will not be integrated into the market system. Therefore, changes to the scheduling and dispatch process will not be required. The Authority and/or a third party will work with the centralised forecaster and intermittent generators to ensure the new arrangements become operational.

(d) The Authority will communicate with affected parties, so they have a clear understanding of the policy changes and new requirements.

[34] We expect the initial contract term to be one or two years.

11. Attachments

11.1. The following appendices are attached to this paper:

- Appendix A: List of submitters
- Appendix B: Submitters' detailed responses to questions in the issues and options paper
- Appendix C: Updated assessment of each option against the evaluation criteria
- Appendix D: Cost-benefit analysis

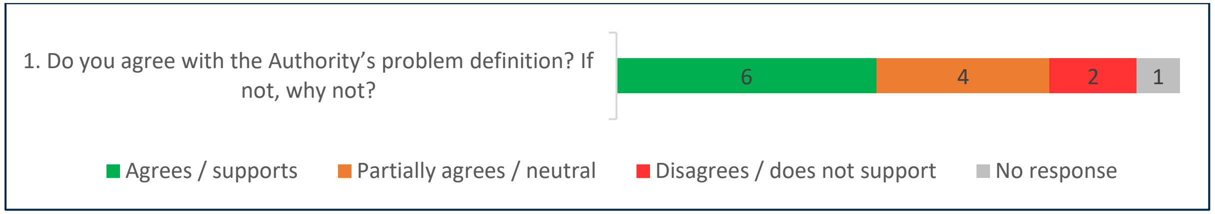
Appendix A: List of submitters

Type	Submitter
Intermittent generators	Genesis Energy [wind]
	Mercury Energy [wind]
	Meridian Energy [wind]
	Lodestone Energy [solar]
	Nova Energy [solar]
Other generators	Contact Energy
	Manawa Energy
Intermittent generator in the process of entering the New Zealand electricity market	Helios Energy [solar]
Transmission	Transpower
Other	Consumer Advocacy Council (CAC)
	ETSI (specialist power system and operations expertise)
	Major Electricity Users' Group (MEUG)
	NewPower Energy (ancillary service agent, electricity generator, metering equipment owner and battery operator)

Appendix B: Submitters' detailed responses to questions in the issues and options paper

Question 1: Do you agree with the Authority's problem definition? If not, why not?

Summary of responses



Submitters that agreed

Submitter	Comment
Contact	Contact noted it agreed with the problem definition.
MEUG	MEUG noted it agreed with the problem definition.
NewPower	NewPower noted it agreed with the problem definition.
Nova	Nova noted it agreed with the problem definition.
Transpower	Transpower noted that market efficiency issues are also often operational issues.

Submitters that partially agreed

Submitter	Comment
Genesis	Genesis' view was that the unit commitment problem is caused by a wider range of factors in addition to inaccurate forecasting of intermittent generation. Genesis noted that the options assessed in this paper, while helpful, will not be sufficient to resolve this problem. Genesis noted that the value consumers place on security of supply remains to an extent unknown in the current market, and it considers there is a high risk that it is currently undervalued. Furthermore, Genesis commented that it is unclear whether the value of lost load has been factored into the analysis.
Mercury	Mercury noted that there appears to be an implicit expectation in the problem definition that intermittent generation forecasts should have a similar level of accuracy as forecasts for hydro or geothermal generation. Clearly, there are inherent features of intermittent generation, such as the respective uncertainty of wind and solar fuel sources, that means this is not the case. Mercury acknowledged that intermittent generation forecasts are likely to improve over time as more information is collected about the performance of individual wind and solar generation sites.
Meridian	Meridian noted that although wind forecasting has been cited as a problem in a lead up to the events of 9 August 2021, its experience is that forward prices do not necessarily lead to thermal commitment, and that it is similar for intermittent generation forecasting too. Given the very small impact on wholesale prices due to under/over forecasting, Meridian thought it is unlikely that increases in accuracy of forecasting will impact on thermal commitment. However, given the increasing proportion of intermittent generation, Meridian thought forecasting accuracy will become a more pressing issue, and so a level of intervention is justified.

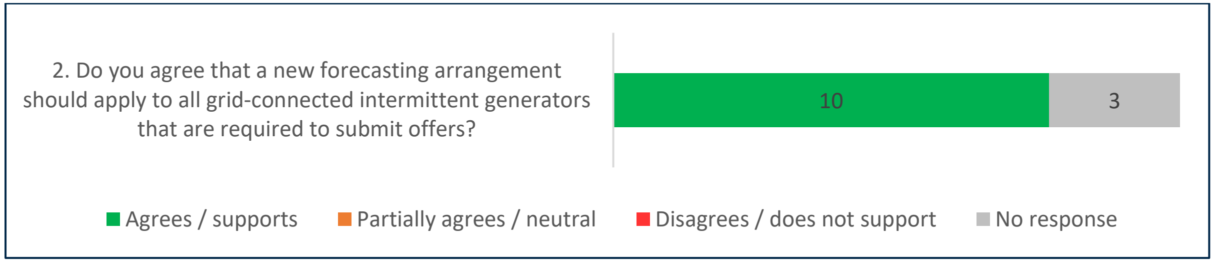
Submitters that disagreed

Submitter	Comment
CAC	The CAC's view was that the issues and options paper does not emphasise enough that inaccurate intermittent generation forecasting leads to higher prices for consumers.
Lodestone	Lodestone agreed with the overarching problem definition of inaccurate intermittent generation forecasting, but it disagreed that forecasts are inaccurate due to a lack of incentives or penalties on generators. In Lodestone's view, the issues and options paper failed to recognise that weather is highly non-linear and the accuracy of weather forecasts deteriorate the further out in time they go.

Submitter	Comment
	Lodestone also noted that the analysis that was appended to the issues and options paper needs to be interpreted cautiously because the base case modelled was based on a “near perfect forecast” 12 hours ahead, which would not be possible.

Question 2: Do you agree that a new forecasting arrangement should apply to all grid-connected intermittent generators that are required to submit offers?

Summary of responses



Submitters that agreed

Submitter	Comment
Contact	Contact noted it agreed that a new forecasting arrangement should apply to all grid-connected intermittent generators that are required to submit offers.
ETSI	ETSI agreed that a new forecasting arrangement should apply to all grid-connected intermittent generators that are required to submit offers. ETSI noted that the practical implementation of such a requirement must take into account the existing intermittent generators and the costs (if any) associated with retrofitting existing equipment and processes to comply with the new arrangements. ETSI recommended allowing sufficient time for existing assets to comply with new arrangements and the use of a sunset clause to ensure compliance by a given date. ETSI suggested that exemptions could be provided for intermittent generators who could demonstrate that the costs to retrofit to meet the new arrangement are prohibitive.

Submitter	Comment
Genesis	Genesis' view was any new forecasting arrangement should include any generator that is required to submit offers, including any generator with installed capacity that is less than 10MW, whether grid-connected or not.
Helios	Helios noted that there is considerable intermittent generation anticipated to come online in the future and the cumulative effect from all assets, regardless of their size, will have an impact on the efficiency of the system. Given the likelihood that intermittent generation will end up being geographically clustered, Helios agreed the 30MW threshold be lowered to reflect the cumulative effect smaller sites may contribute to inaccuracy.
Lodestone	Lodestone noted it agreed that a new forecasting arrangement should apply to all grid-connected intermittent generators that are required to submit offers.
Mercury	Mercury suggested that the arrangements may need to reflect the inherent differences between wind and solar generation. For instance, the current wording in the Code for persistence forecasting may not be suitable for solar generation.
Meridian	Meridian noted it agreed that a new forecasting arrangement should apply to all grid-connected intermittent generators that are required to submit offers.
NewPower	NewPower noted it agreed that a new forecasting arrangement should apply to all grid-connected intermittent generators that are required to submit offers.
Nova	Nova suggested that the impact of 'behind the meter' resources needs to be monitored, and suitably tailored forecasting requirements should be introduced where embedded cumulative scale becomes an issue for demand-side forecast accuracy at the grid exit point. Nova noted that while the combined output of intermittent generators within a region can be closely correlated, it is still important the individual output forecasts are reasonably accurate.
Transpower	Transpower suggested that the new requirements should also apply to distribution-connected intermittent generators who are required to submit offers.

Question 3: *Note this question is referring 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.

Submitters that responded

Submitter	Comment
Contact	Contact estimated that it makes the incorrect decision to start or stop its thermal units roughly 6-10 times a month, particularly for its Stratford peaking plants. This causes a range of problems. If the Stratford peaking plants are close to the marginal plant, Contact will commit them based on the short schedule price. If more wind is available than what was forecast, Contact would generally run one or both plants at below their short run marginal cost (SRMC). Alternatively, Contact can offer the plant at LRMC, but if less wind is available compared to what was forecast, the plants are not available at the SRMC. Therefore, Contact must deploy more expensive generation. Contact also noted that constantly stopping and starting its thermal units also causes significant wear. Running them this way can increase their LRMC. As a result, Contact often prices its peaking plants up in times of highest volatility to ensure they are not deployed in a way they are not designed for.
ETSI	ETSI noted that while it does not have thermal assets, the relationship between thermal unit commitment lead time, forecast accuracy and incentives in a decentralised-only arrangement, and an energy-only market is complex. In an energy-only market with independent intermittent generators, the natural incentive for intermittent generators to accurately forecast ahead of time is weak.
Genesis	Genesis noted that unit commitment decisions are made ex-ante based on information available at the time. Therefore, Genesis does not think it is meaningful or useful to try and provide an ex-post assessment of unit commitment decision-making. Genesis also noted the assessment of whether a decision was ‘correct’ (ie, rational) depends to an extent on whether you take the perspective of an individual generator or the system. This is particularly true for cases where wind is over-forecast and thermal generation that could have been committed remains offline. In this instance, the cost to a generator may not be significant, whereas the cost to the system will be an economic cost reflected in higher prices paid by consumers.

Question 4: What else, if anything, should be considered when assessing the relative advantages and disadvantages of the four forecasting arrangements the Authority has identified?

Submitters that responded

Submitter	Comment
Contact	Contact thought the disadvantages of decentralised forecasting have been overplayed in the issues and options paper. Contact noted that building an intermittent generation asset is not a small undertaking, and parties that undertake these developments will have significant capability. Contact did not think that standards will create a meaningful barrier to entry. Contact also thought that if standards and incentives are well developed, there is no reason to expect that new entrants would not be able to meet these requirements and provide accurate forecasts.
Genesis	Genesis noted that there is a degree of interdependency among the design considerations raised in the issues and options paper. For example, the type of accuracy standards, incentives and penalties that are most effective and appropriate will differ for a centralised versus a decentralised arrangement.
Helios	Helios was also concerned about the cost implications and the benefits of scale the larger participants have relative to smaller participants. This could risk slowing the rollout of intermittent generation assets. Helios also suggested the Authority should consider the ability to adapt to changes in technology and generation mix in the future, and systems that work for both wind and solar forecasting.
Lodestone	Lodestone suggested that the Authority should also consider the financial ability for participants to comply with more onerous forecasting requirements. For example, if intermittent generators were required to source more accurate third-party weather forecasts and develop more advanced and complex models to produce more accurate generation forecasts, this would create an unlevel playing field between the large generator retailers with large intermittent generation sources and smaller new entrant generators. The larger participants would have greater economies of scale in their portfolio to cover the costs and implementation of such as system, whereas it could incur significant costs to say a community-owned solar or wind farm that is just over the 10MW threshold.
Mercury	Mercury suggested that the Authority should also consider the impact of each forecasting arrangement on the reserves and frequency keeping markets.
Meridian	Meridian suggested that the Authority should also consider how useful the option would be for participants (ie, consideration of what is commercially pragmatic).

Submitter	Comment
Nova	Nova noted that there will be diminishing returns for the level of resources applied to achieve more accurate intermittent generation forecasts. It also noted that forecasting intermittent generation may be easier in some regions than others. Similarly, there may be economies of scale if there are lots of intermittent generation sources in close proximity. However, generators with intermittent generation assets that are located far from other assets will not be able to share costs and resources with other generators. Nova also noted that a centralised arrangement may not have the same commercial drivers to continually invest in improving forecasts, except when a service contract needs to be renewed.
Transpower	Transpower suggested that the Authority should also consider the resilience of each arrangement and whether arrangements are more or less likely to increase the diversity of weather forecast information from which the intermittent generation forecasts are based. Transpower noted that while it would be possible for the Authority to require intermittent generators to engage with multiple weather forecasts under a decentralised arrangement, such a requirement may be more practical under a centralised arrangement.

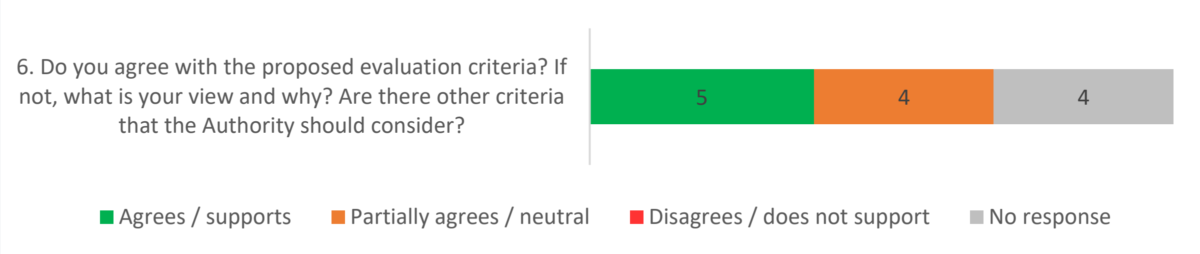
Question 5: What other types of forecasting arrangements, if any, should be considered to improve the issue of inaccurate and unreliable forecasts?

Submitters that responded

Submitter	Comment
Contact	Contact indicated it was not aware of any other approaches.
ETSI	ETSI suggested that the Authority could consider amendments to the Code to mandate data and information provision so that a baseline level of data and information can be relied upon to build forecast models (for a decentralised or centralised arrangement). It suggested the Energy Conversion Model requirements in the National Electricity Market in Australia could be used as a guide. ETSI also noted that improving decision making whilst using forecasts for multiple contingency events (such as the 9 August 2021 grid emergency) are a growing risk, and an example of the impact when multiple seemingly remarkable events coincide.
NewPower	NewPower noted that compared to wind generation, solar generation has a much lower impact on peak generation due to its profile, particularly in winter. NewPower did not support a 'one size fits all' approach for all types of intermittent generation types.
Nova	Nova noted that as long as the incentives (or penalties) provided for decentralised forecasting are appropriate, it is likely that individual generators will contract out the forecasting to third-party services. Competition in the market can be expected to lead to economies of scale and increased use of technology to make the process more accurate and efficient.
Transpower	Transpower noted that within each arrangement, there are multiple decisions to be made prior to implementation. For example: a) the source of weather forecasts b) back-up requirements c) the circumstances in which the system operator may substitute decentralised intermittent generation offers d) whether parties must source multiple forecasts to improve diversity and the likelihood of forecast accuracy. Transpower noted that the Australian Energy Market Operator (AEMO) has advised that for its centralised forecast, it currently procures two weather forecasts and two intermittent generation forecasts. AEMO then selects a forecast based on the 'consensus' view across all forecasts. However, AEMO is currently transitioning from this approach to an approach that better assesses the impacts all of weather forecasts combined.

Question 6: 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?

Summary of responses



Submitters that agreed

Submitter	Comment
ETSI	ETSI agreed with the Authority's evaluation criteria and thought the criteria support the objective of ensuring any changes are in the long-term interests of consumers. ETSI emphasised the following: a) For the 'reliability' criterion – improved forecast accuracy should not be viewed as a silver bullet that will mitigate all risks to power system security and reliability. By improving forecast accuracy, the risks to power system security and reliability are reduced, however the effective management of these risks involves appropriate integration of the forecasts into power system functions and processes as described in our submission above. b) For the 'uses an exacerbators pays approach' criterion – the design and implementation of such a mechanism with a decentralised-only arrangement in an energy-only market is complex. This is one of the reasons why ETSI recommends a hybrid arrangement.
Helios	Helios agreed the criteria covered the major points, although it suggested consideration is made for the ability to forecast the cumulative impact from smaller generators who are not required to place bids in the market.
Lodestone	Lodestone suggested the solution should take into account economies of scale and keeps a level playing field between large and small intermittent generation.

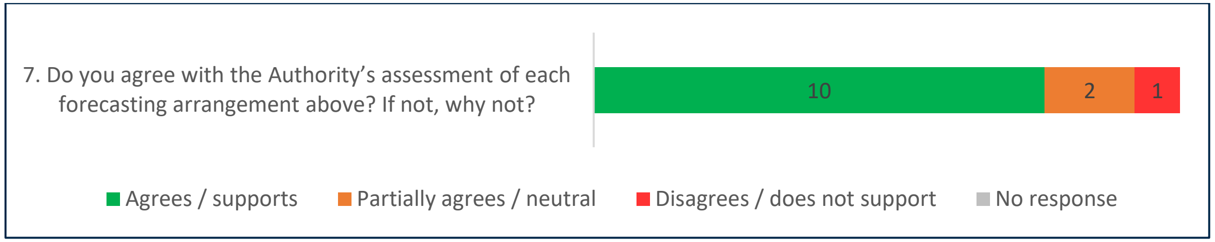
Submitter	Comment
Mercury	Mercury noted it agreed with the proposed evaluation criteria
Transpower	Transpower suggested the Authority should also consider the ability for a solution to address multiple issues and developments under consideration. Transpower thought the Authority should reassure itself it has considered the wider benefits of options before foreclosing. For example, an ahead market may deliver benefits in demand side participation, managing winter peaks, and the orderly exit of thermal generation. Assessing the benefits of an ahead market in the narrow confines of each issue requiring solving is unlikely to deliver a positive cost-benefit analysis but if considered as a totality may deliver the best outcome for the long-term benefit of consumers.

Submitters that partially agreed

Submitter	Comment
Contact	Contact broadly agreed but thought the criterion ‘straightforward to implement’ may be double counting other criteria such as ‘enhances competition’ ‘timely’ and ‘value for money’. Contact suggested this could be replaced by ‘implementation risk’. Contact thought implementation risk to be the greatest challenge under a decentralised arrangement as it would be very hard to get standards and incentives accurate and may not result in the desired outcomes on the first try. It is likely they will require ongoing adjustments.
Meridian	Meridian thought some of the categories were repetitive (for example, ‘efficiency’ is probably not very different to ‘uses an exacerbators pays approach’). Meridian suggested the Authority could also consider how useful the option would be for participants, including what is commercially pragmatic, having regard to the New Zealand market.
NewPower	NewPower agreed with the criteria but thought it is important that the criteria chosen should promote (or at least not inhibit) the transition to more sustainable generation by not imposing significant additional cost on renewable generation.
Nova	Nova suggested the concept of ‘futureproofed’ should also consider the incentives for enhancing forecasting accuracy and cost effectiveness over time. A centralised approach may not have the same commercial drivers to continually invest in improving forecasts, except when it comes time for service contract renewal.

Question 7: Do you agree with the Authority's assessment of each forecasting arrangement? If not, why not?

Summary of responses



Submitters that agreed

Submitter	Comment
CAC	The CAC thought a centralised arrangement would remove the barriers that smaller participants would face under a decentralised arrangement. The CAC also thought a centralised arrangement would most effectively minimise impacts on other market participants and the electricity system.
ETSI	ETSI supported the hybrid arrangement as the central forecast would provide a basis on which to benchmark the decentralised forecast, should this be desired. This could be used to set appropriate standards against which to measure performance.
Manawa	Manawa noted that the centralised forecasting arrangement works well in the Australian National Electricity Market and is the most futureproofed option. Genesis also shared this view.
Mercury	Mercury preferred the hybrid arrangement, noting it could lead to benefits from competition and improve the quality of forecasts. ETSI also preferred the hybrid arrangement.
Meridian	While it was supportive of a centralised arrangement, Meridian noted the key downside to this is that it would concentrate risk in one provider, and potentially risks introducing bias. Meridian noted that Ireland and Texas have centralised arrangements with multiple forecasters as part of their centralised arrangements and suggested it would be beneficial if we adopted a similar approach.
MEUG	MEUG's view was that there would be merit in exploring either a decentralised forecasting arrangement with incentives/standards, a centralised forecasting arrangement or a hybrid arrangement.

Submitter	Comment
Transpower	Transpower agreed with the Authority's assessment of each option. Transpower noted that for either the centralised or hybrid arrangements, the timeliness, value for money, and implementation scores would all reduce if the option is integrated with the system operator's market system. Transpower noted that the ahead market and balancing market option would likely score poorly in a cost-benefit analysis, but it may deliver benefits in demand side participation, managing winter peaks, and the orderly exit of thermal generation.

Submitters that partially agreed

Submitter	Comment
Contact	Contact agreed with the Authority's assessment of each option but questioned the relative impact of some of the criteria the Authority used to assess the advantages and disadvantages of each option. For example, Contact's view was that the 'effectiveness', 'efficiency' and 'reliability' scores for the centralised option should be 'medium' (rather than 'high') due to the risk of the centralised forecast being inaccurate and creating a system-wide bias.
Genesis	While Genesis could see the potential benefits of a centralised arrangement, it noted the following reservations: a) Under a centralised arrangement, it is unclear if any incentives for accurate forecasting, and penalties for inaccurate forecasting, will be sufficiently proportional to the impact such accuracy/inaccuracy can have on spot prices to be effective and consistent with the Authority's objectives. This is because the value of any contractual arrangement with a central forecaster is unlikely to be of an order of magnitude whereby incentives/penalties proportionate to the market impact can be reasonably included. That is, it seems unlikely any central provider will willingly enter a contractual arrangement whereby they accept liability for the market impact of inaccurate forecasting. b) Under a hybrid arrangement, it is unclear why a generator would choose to self-forecast, if this would also mean incurring liability for any errors. It is likely a hybrid arrangement will only work if generators can submit their own forecasts to the central forecaster, with the central forecaster then taking on responsibility for providing a system-wide forecast with liability for any material errors. Some incentives will likely also be needed for generators to submit their own forecasts. Genesis suggested that if a centralised arrangement is preferred, the centralised arrangement used in the Australian National Energy Market, whereby a central forecaster provides solar and wind forecasts for the system with data inputs from generators, could be a suitable example of an arrangement that may work in New Zealand, albeit it would be rational to allocate costs to sources of load and intermittent generation but exclude non-intermittent forms of generation (whereas in Australia it appears costs are recovered from all participants).

Submitter	Comment
	Genesis also noted that forecasting accurately is likely to grow more difficult in the future, not just because of the growth in intermittent generation but also due to growth in behind-the-meter demand response (whether coordinated or not). As a result, the job of a central forecasting provider may grow more difficult. A system where generators and retailers are liable for their forecasting errors (generation and demand response), such as a day-ahead market, provided it applies to every load and all forms generation source (not just intermittent generation) might prove more effective and durable (future-proofed) in helping with unit commitment decisions and general market reliability. Therefore, Genesis suggested the Authority explore this further longer-term (noting it will not be possible to implement before winter 2024).

Submitters that disagreed

Submitter	Comment
Nova	Nova disagreed with the Authority's assessment of the benefits of the hybrid arrangement. In Nova's view, the hybrid arrangement would likely to lead to duplication and excessive pass-through expenses for participants who cannot self-forecast. Nova did not think the hybrid arrangement should score highly on the 'futureproofed' criteria.

8) The Authority has not weighted the criteria based on importance. Are there particular criteria that you consider to be more important than the others?

Submitters that responded

Submitter	Comment
Contact	Contact suggested that ‘effectiveness’, ‘efficiency’ and ‘reliability’ should be weighted higher as these are the main goals of this project. It may also be appropriate to weight ‘implementation risk’ higher too to recognise that even where the option has the potential to score high elsewhere, if there is a risk that this will not be the outcome, then some down-weighting is appropriate. This change would retain the hybrid arrangement as the best and create a bigger gap from the other options.
ETSI	ETSI suggested that whilst it is possible to weight the criteria, it may be more appropriate to ensure some of the criteria determine the minimum expectations. For example, there is not much point having a value for money system that is easy to implement and which attributes cost-to cause, if it does not mitigate risks to system security (reliability) and which meets future requirements of a renewables-based power system. Therefore, ETSI suggested it may be more appropriate to have 1st order (required) attributes, and 2nd order (nice to have) attributes. ETSI did not think this would result in a different leading option in this case, and the hybrid arrangement would still be the preferred option.
Genesis	Genesis thought the criteria ‘reliability’ and ‘mitigates risks to security of supply’ should be weighted very highly, as the consequence of getting this wrong (ie, load management) is high to the industry, customers and economy as a whole. Genesis agreed with the desirability of ‘enhancing competition’ and ensuring forecasting requirements do not act as an unreasonable barrier to entry. ‘Successfulness in other jurisdictions’ may be less important than other factors given differences in New Zealand’s electricity system, such as the high proportion of hydro and our lack of connectivity to other systems. Genesis noted there may be trade-offs between the criteria that should be considered carefully by the Authority when assessing the options. For example, ‘timely’ and ‘straightforward to implement’ vs ‘futureproofed’ (ie, an arrangement that can be implemented before winter 2024) may not be the best long-term arrangement. A day-ahead market may prove beneficial longer-term, notwithstanding the fact it cannot be implemented by winter 2024.
Helios	Given the main goal of this work is to improve market effectiveness, Helios thought it seems more weighting should be given to the effectiveness and efficiency. Helios also considered it important to implement a futureproofed system that can deal with increased

Submitter	Comment
	intermittent generation without the need for more upgrades and consultation. Helios anticipates seeing many new projects enter the market at a range of sizes and therefore suggest the new system allows for the cumulative impact from generators =10MW.
Lodestone	Lodestone did not think there were particular criteria that were more important than the others
Mercury	Mercury did not have specific views regarding the relative weighting of the criteria.
Meridian	Meridian thought that ‘value for money’ is a very important criterion and would like to see this given more weight.
NewPower	NewPower thought ‘enhances competition’ should be considered important, to the degree that additional compliance costs do not create a barrier to entry of new renewable generation. Similarly, ‘value for money’ should have a high weighting. Any forecasting costs should be easily predictable to support business cases for new renewable generation. ‘Timeliness’ should have a lower weighting in as much as it should not cause the dismissal of an option which creates better long-term outcomes. For the options proposed, this doesn’t appear to be a decider.
Nova	Nova thought the criteria that are more directly aligned to the problem definition could have a higher rating (e.g. effectiveness, efficiency), though a balanced/even weighting is less subjective. Futureproofing is a key consideration, while the electrification transition is underway, but Nova did not agree that hybrid arrangement should rate highly for this.
Transpower	From an operational perspective Transpower would weight ‘effectiveness’ and ‘reliability’ most highly. However, Transpower agreed with the outcome of the Authority’s assessment process.

9) Are there additional criteria that the Authority should be considering?

Submitters that responded

Submitter	Comment
Contact	Contact thought 'implementation risk' should also be considered.
Genesis	Genesis thought that one factor that may require further consideration to ensure any new arrangement remains durable and futureproofed is how other renewable sources of electricity, particularly solar or offshore wind, will operate under any new requirements.
Helios	Helios suggested the Authority consider the impact from regional intermittent generators <10MW
Lodestone	Lodestone suggested the solution should take into account economies of scale and keeps a level playing field between large and small intermittent generation.
Mercury	Mercury did not suggest additional criteria for the Authority to consider.
Meridian	Meridian thought some of the categories were repetitive (for example, 'efficiency' is probably not very different to 'uses an exacerbators pays approach'). Meridian suggested the Authority could also consider how useful the option would be for participants, including what is commercially pragmatic, having regard to the New Zealand market.
Nova	"If the party determining how much money is to be spent on forecasting has 'skin in the game' in terms of the benefits of improved accuracy and costs of acquiring the forecasts, then they are more likely to support appropriate investment. It has been apparent for over ten years that improved forecasts would be beneficial to the market and the capability to develop that could have been achieved in that time if the appropriate incentives were in place. For instance, the Authority notes that the generators with both wind and hydro capacity have done some work improving their wind forecasts. "
Transpower	Transpower thought a resilience or back-up functionality criteria is applicable to all options. Transpower questioned what obligations or incentives would exist under each option to provide resilience and redundancy in intermittent generation forecasts.

Question 10: How frequently should intermittent generation forecasts be updated, and how often should intermittent generators be required to revise their offers to reflect updated forecasts?

Submitters that responded

Submitter	Comment
Contact	Contact supported updates every 30 minutes.
ETSI	ETSI suggested that forecasts should be progressively updated up to the moment of dispatch. ETSI's view was that the frequency and the length of each forecast should be aligned with the power system functions and processes which the forecasts underpin.
Genesis	Genesis suggested that intermittent generators should be required to submit a forecast for the next 36 hours every two hours.
Helios	Helios thought forecasts should be updated every hour to allow for markets to monitor. Its view was that generator offer updates should be more frequent the closer it gets to gate closure but not so onerous in the outer days and hours due to inaccuracy of forecasting. This would mean hourly updates 40 hours out would not add to accuracy and may cause wild changes to market prices that would not help other generators with offer efficiency.
Lodestone	Lodestone's view was that six hours seems to be a reasonable assumption for updating the underlying weather models as this would strike a balance between accuracy and affordability. It suggested the maximum update frequency at any time should be half hourly.
Mercury	Mercury suggested that when there is significant change in the forecast, the market should be informed immediately.
Meridian	Meridian noted the consultation suggests that forecasts could be updated as frequently as half-hourly, to fit with trading period timeframes, but that this would have an associated cost for generators. Meridian thought it was difficult to comment on whether this would be useful or not without more information on the level of cost and the way in which this would work. Although more frequently updated forecasts could aid accuracy, it is unclear if the benefits from this would exceed the costs.
NewPower	NewPower noted the need to consider the higher costs that would arise if forecasts needed to be updated more frequently, and weigh these against the expected benefits.
Nova	Nova thought intermittent generators should operate within the same rules as the thermal and hydro generators to update their generation offers. If the generator can achieve the required levels of accuracy based on six-hourly updates and a model based on trend in the shorter term, then that should be satisfactory if it meets the target accuracy for energy offers. However, if it cannot achieve that

Submitter	Comment
	then more frequent forecasts should be required. For example, in the case of solar, clearly the diurnal pattern of output is known, and output will generally be a percentage of that.
Transpower	Transpower noted that forecasts only change when the underlying weather forecast changes. Consequently, Transpower suggested aligning the obligations around the frequency of updates with availability of new weather forecasts (eg, every half-hour). Transpower suggested that if an intermittent generator receives an updated forecast that varies significantly to its previously submitted offers, it should be required to submit a revised offer (similar to what clause 13.20 of the Code currently requires). Transpower noted that the translation of intermittent generation forecasts into offers is what gives visibility to all participants of expected intermittent generation output and consequent market outcomes. Transpower's view was that it makes sense to co-design these elements.

Questions 11 and 12: Do you think the Authority should implement accuracy standards? If not, please explain why.

If the Authority was to implement accuracy standards:

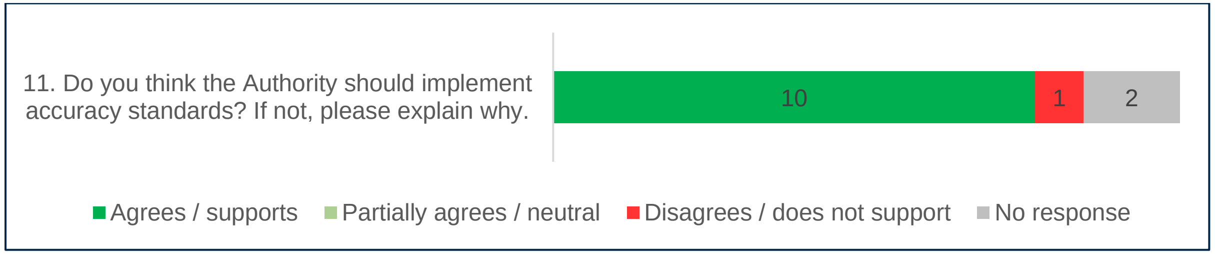
a) **do you think outcome process standards would be more effective?**

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 30MW of the amount that was forecast, or should the MW compliance 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?**

Summary of responses



Submitters that agreed

Submitter	Comment
CAC	The CAC suggested that at T-12 hours, a P50 forecast should be +/- 10% from actual generation at real time, and at T-3 hours this should be narrowed to +/- 1MW.
Contact	Contact's view was that both process and outcome standards are important. Contact suggested that process standards be high-level to ensure they do not become a barrier to future innovations and market evolution. Contact noted that outcome standards are important for providing the measurement for incentives and penalties.

Submitter	Comment
ETSI	ETSI noted it is challenging to design accuracy standards in an energy-only market due to the complexity of how to recover costs for any incentive payments and how to distribute any penalty payments. ETSI suggested that the system operator be empowered to maintain the accuracy standards, which should be developed through consultation with industry.
Helios	Helios suggested that a percentage basis would be the better process for accuracy because small generation inaccuracy over multiple sites can cause the same inaccuracies as forecasting one large site with an inaccurate generation forecast.
Lodestone	Lodestone's view was that outcome standards are likely to be more effective as they could allow participants to use innovation (eg, artificial intelligence) to generate forecasts. Lodestone's view was that if outcome standards are chosen, they should differ across timeframes. If process standards are chosen, the Authority could choose the process to achieve the outcomes it desires across different timeframes. Lodestone suggested that the accuracy standard should remain at 30MW, whereas Contact suggested the accuracy standard should be set at +/- 15MW.
Mercury	Mercury suggested the current threshold of +/- 30MW in the Code should be amended to include a percentage value of output to reflect the fact that the capacity of each wind farm differs.
Meridian	Meridian noted there are many tools, techniques and approaches to forecasting and being too prescriptive around processes can negatively affect innovation. Meridian's view was that it is more suitable to have staggered standards, with accuracy obligations increasing closer to real time. Meridian thought the current 30MW threshold is a good starting point. As an example, Meridian suggested that an initial accuracy standard is that actual generations falls within 30MW of forecast generation 98% of the time.
NewPower	NewPower favoured process standards. NewPower's view was that multiple standards should be applied across timeframes as weather forecasts become more accurate. Accuracy standards should be relative to the installed capacity rather than a fixed MW value to future proof the code and make it agnostic to the size of generation providers.
Nova	Nova suggested that the accuracy requirement should relate to the time until dispatch (ie, a wider scope should apply for forecasts 12 hours ahead of dispatch, and a tighter margin for say 30 minutes ahead of dispatch). Nova's view was that the allowance for accuracy should be determined by long-run measures of tracking performance rather than measures of MW or percentage of capacity for individual trading periods. Nova also suggested that the standards should not look to ensure individual forecast errors are within MW of forecast as this could result in generators curtailing generation to stay within a band. If accuracy standards are implemented and are based on the

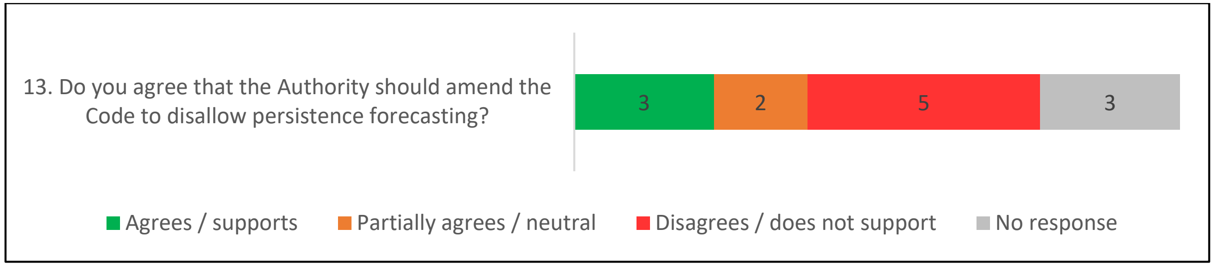
Submitter	Comment
	percentage of a generator's capacity, Nova's view was that these should be based on a percentage of available capacity, rather than a percentage of installed capacity. Nova's view was that under a centralised arrangement, accuracy requirements should not initially be required if the forecasting objective/standard is clearly specified with regular reporting to measure performance. Accuracy requirements could be introduced later if deemed required by the industry.
Transpower	Transpower's view was that process standards risk restricting innovation and forecasting developments that do not align with the prescribed process. Transpower noted that persistence offers are a good example of process standards locking in a practice which went from 'best practice' to 'poor practice' over time. Transpower suggested that accuracy standards should be based on percentages of installed capacity and absolute MW minima like the offer revision obligations for non-intermittent generation in the Code.

Submitters that disagreed

Submitter	Comment
Mercury	Mercury did not consider that it would be appropriate to implement accuracy standards as every intermittent generation site differs with different sensitivities at different parts of the power curve. As such, any accuracy standards would be arbitrary. In addition, Mercury thought accuracy standards should reflect the inherent nature of wind forecasting where the long/medium terms are more a probability (confidence intervals) and the short-term could be deterministic. Also, when it comes to the compliance threshold, the addition of a percentage of available capacity would be more reflective of operational conditions than the current threshold value of +/- 30MW included in the Code.

Question 13: Should the Authority amend the Code to disallow resource persistence forecasting?

Summary of responses



Submitters that agreed

Submitter	Comment
Contact	Contact supported this change.
Helios	Helios supported the prohibition of persistence forecasting. Helios thought persistence forecasting will perform differently for different types of generation technologies (eg, similarities may exist for wind but may vary for solar given its time-of-day variability, whereas day-to-day forecasting may perform better for solar than wind).
Transpower	Transpower supported the prohibition of persistence forecasting. In Transpower's view, as well as masking predicted changes in output from wind generation, persistence offers are unsuitable for solar generation. When designing the replacement arrangement, Transpower thought the Authority should ensure intermittent generation offers are sufficiently updated approaching real-time, either through accuracy incentives/standards or obligated offer update timings. Transpower noted that the system operator currently has visibility of intermittent generation in real-time from generator SCADA. The market can also see actual wind generation (updated half-hourly) and offers via WITS.

Submitters that were neutral

Submitter	Comment
ETSI	ETSI's view was that persistence forecasting can be appropriate when forecasting a very short lead-time ahead (eg, for wind generation 5-minutes ahead of dispatch). ETSI thought persistence forecasting is not appropriate at longer lead-times and is very risky when performed at the lead-times which coincide with thermal unit-commitment decision making. ETSI noted that this risk is magnified when there are weather systems moving across New Zealand that lead to wind power ramping events. In these events, not only is the system at risk of forecast magnitude errors, but due to the risk of temporal changes (ie, the weather system moving faster or slower than predicted), the size of the forecast error is magnified by the timing of the ramp.
Mercury	Mercury's view was that persistence forecasting has its place, where appropriate, but it should be left to the individual generator to determine this. Mercury noted that the current wording in the Code "the assumption that the variable resource conditions ... will persist" may not be strictly appropriate for solar where the path of the sun is variable but predictable, while other factors such as cloud cover are not. Mercury suggested a more nuanced interpretation of persistence – eg, assuming persistent cloud cover but not persistent sun position – would be more appropriate.

Submitters that disagreed

Submitter	Comment
Genesis	Genesis did not think that persistence forecasting should be disallowed completely. However, it noted that in its experience, persistence forecasting is only accurate over a very short period of between 30 to 60 minutes before dispatch. Therefore, it should not be used over a time horizon of more than 60 minutes. Genesis also thought consideration should be given to the methodology used in persistence forecasting (eg, a single snapshot of generation sometime during the last period versus an average over some length of time), as generation sometimes fluctuates significantly minute by minute and a snapshot might not be representative. Genesis' view was that the timing of the submission of a persistence forecast should also be as late as possible in the current trading period, so that it is as reflective as possible of current/near-term conditions.
Meridian	Meridian's view was that persistence forecasting has not been shown to be inaccurate. It noted that persistence forecasting works well for Meridian and enables it to coordinate its portfolio of mixed generation types. The significant size of Meridian's wind portfolio means that there are strong incentives on Meridian to ensure that its forecast information is accurate and timely. Meridian's view was that the

Submitter	Comment
	Authority should not disallow persistence forecasting, and it would like to see more monitoring of forecast accuracy to build an evidence-base before this is considered further.
NewPower	NewPower noted that it did not have sufficient knowledge and experience in wind generation forecasting to comment. However, it suggested that unless a better forecasting methodology can be proposed, persistence forecasting should continue to be used.
Nova	Nova did not think that persistence forecasting should be disallowed. Instead, Nova thought intermittent generators need to be required to provide more accurate energy offers to the system operator, and they need to demonstrate that they are not systemically under or over forecasting. Nova suggested the Code should specify minimum requirements for accuracy of offers over time and how the measures are determined.

Questions 14 – 16: Questions related to incentives and compliance

Submitters that responded

Submitter	Comment
CAC	The CAC was supportive of applying penalties for non-compliance (but did not specify what these could be or how they could be applied).
Contact	Contact thought the quality incentive regime implemented by the Commerce Commission for electricity distribution businesses may be an appropriate model. This sets an incentive rate for outcomes within certain bounds (caps and collars). It also limits the size of incentives and disincentives so as it is not overly onerous, but still provides an incentive for improved outcomes. This is then complemented by more formal enforcement action if outcomes fall outside of an acceptable range. This could apply to both a decentralised and centralised arrangement. Contact supported setting penalties for not meeting the standards. Penalties for under forecasting and over-forecasting should be symmetrical. Contact noted that some parties may bias towards under-forecasting, but it thought that tilting the rewards/penalties is unlikely to change this and may just result in lower returns for forecasters.
ETSI	ETSI supports the implementation of well-designed incentives and penalties. The incentives and penalties should be outcome-oriented, technically feasible and not prone to gaming. ETSI suggested that one such design that meets these criteria whilst recognising the inherent uncertainty in forecasts is the application to forecasts of a penalty deadband outside of which a financial penalty is applied. To incentivise improved forecast accuracy, the penalty payments are distributed to the most accurate forecasts within the deadband. Over time the penalty deadband can be reduced to drive further forecast accuracy improvements. Under a centralised arrangement, ETSI suggested that contract KPIs could be used for performance-based incentive payments, and similarly for performance penalties. When contracts are due for renewal a competitive procurement process with multiple vendors will ensure the best commercial and technical outcomes. Any vendor contract should also consider the ability to terminate early any contract for multiple unreasonable forecast errors. ETSI recommended against different penalties for over and under generating. Penalties which encourage forecast providers biasing their forecasts can consequently lead to skewed forecasts and one-sided errors, which can accumulate reducing forecast accuracy overall and the system security benefits.
Genesis	Under a decentralised arrangement. Genesis' view was that, consistent with the causer/exacerbator-pays principle, any costs resulting from inaccurate forecasting should be allocated to generators responsible for inaccurate forecasting. This should be in the form of 'over / under' fines related to the clearing spot price for the appropriate node, with charges to be returned to generators. Genesis thought

Submitter	Comment
	such an arrangement would be most effective where charges/fines are proportionate to the materiality of the impact of the inaccuracy (eg, based on the impact of inaccurate forecasting on spot prices.). Similar to an ex-ante price sensitivity run, an ex-post analysis of final price with actual generation vs. what was forecast could help value the cost of errors and help with allocation to the different market participants. Some bounds could be added e.g. penalties only apply if a certain inaccuracy threshold (%) is exceeded. Genesis thought this should also be accompanied by changes to the accuracy threshold (preferably a percentage threshold) to ensure a fair and level playing field, with a minimum materiality threshold to prevent immaterial errors being penalised unnecessarily. Under a centralised arrangement, Genesis suggested that financial incentives could be built into the contract with the forecast provider based on the overall accuracy of the forecast they produce. Genesis thought penalties should apply to all periods, and not just over those in which over-generating and under-generating has a marked impact on spot prices. Genesis thought any penalties should be the same for over and under forecasting. If there was a bias in either direction, then this would encourage the forecast provider to skew their forecasts in the direction of the lower penalty amount which could reduce its accuracy. For example, if there was a greater penalty for under-generating then it would encourage under-forecasting to avoid the higher penalty. Genesis also noted that one limitation of any central arrangement is that it may not be possible to impose penalties for inaccuracy that are proportionate to market impact, as for a decentralised arrangement. This is because the value of a contract with any central provider is unlikely to be of an order of magnitude proportionate to market impact of material forecasting inaccuracies. Genesis suggested the Authority consider this issue carefully in the next phase of its design work.
Helios	Helios' view was that incentives and penalties need to evolve over time and that the approach may differ by generation technology type.
Lodestone	Lodestone's view was that the applicability of incentives and penalties his depends on whether the system is centralised or decentralised. For a centralised system where a provider is being paid to provide forecasts, Lodestone thought there should be penalties for not achieving the agreed level of accuracy. For a decentralised system, penalties are likely to disadvantage smaller generators and create a barrier to entry over larger generators. Incentives might be the better approach in a decentralised system, to support the smaller generators to implement better forecasting techniques. Lodestone noted that under a decentralised system, generators will inevitably need access to the advanced weather forecasting models that are run by NIWA or MetService (ie, a data feed of wind or solar resource forecast specific to their generation locations). They then need automated tools to automatically process this data, apply any known plant constraints and generate an offer file which needs to be uploaded to WITS. Such a system is complex and costly to implement and could be quite a burden on a small intermittent generator and therefore a barrier to entry. Incentives might be in the form of providing financial support to smaller generators to access such data and develop such systems.

Submitter	Comment
	Under a centralised arrangement, Lodestone thought there will need to be some commercial tension, but presumably a penalty regime would not exceed a certain percentage of annual revenue, otherwise the regime will be too commercially risky for any provider. Lodestone thought any penalties should be the same for over and under forecasting (to avoid introducing bias).
Mercury	Mercury suggested lowering the compliance burden for parties that forecast accurately. Under a decentralised arrangement, Mercury noted that intermittent generators in general have the commercial incentive to improve the quality of their forecasts. This may take time, however, as operational data is gathered particularly for a new windfarm site, under different weather conditions. Under a centralised arrangement, Mercury proposed that intermittent generators should pay for it on a $/MWh basis, and Transpower should submit it into the market. Alternatively, if the Authority determines to implement a hybrid centralised and decentralised approach, then Mercury proposes that those intermittent generators with decentralised forecasts that are not as accurate as the centralised forecast should contribute to the cost of the centralised forecast. This would create a competitive tension and an incentive for market participants to improve the quality of their forecasts.
Meridian	Meridian noted the inherent difficulty in designing penalties, given the inaccuracies generally only result in small impacts to wholesale prices. This means that the 'harm' is often quite small. Meridian suggested that this could be addressed by requiring forecasts be within a range (eg, small and infrequent instances of under/over forecasting would not attract penalties, but larger and more consistent ones would). Meridian suggested that one possible area for incentives could be to have a lowered compliance burden upon participants who can demonstrate consistently accurate forecasts (effectively the opposite of clause 13.86A(2), which requires intermittent generators to supply a monthly report if they generate at a level that is 30MW below their forecast of generation potential on one occasion or more in a given month). Meridian's view was that under a centralised arrangement, there should not be incentives and penalties for inaccurate forecasts on intermittent generators as generators will have no control over the forecasts. If there are penalties, they should be tied to wilful non-compliance or error, rather than the accuracy of the forecasts.
NewPower	NewPower favoured process standards and thought that where failure to follow process results in significant market impact, a penalty should be introduced. If process standards become part of the audit process, the incentive of having/following the right process will be recognised by audit requirements. NewPower suggested that under a decentralised forecasting model, reimbursement of (a reasonable level of) forecasting costs where forecasting meets accuracy targets would be a strong incentive to get this right.

Submitter	Comment
	NewPower suggested that under a centralised forecasting arrangement could be recognised with financial incentives for meeting certain performance goals in forecasting – with the added value being given to thermal generators, incentives could be funded by this part of the industry.
Nova	Nova's view was that under a centralised model, mandatory accuracy requirements should not be required, at least initially, if the forecasting objective/standard is clearly specified with regular reporting to measure performance. Accuracy requirements could be introduced later if deemed required by the industry. The costs of providing accurate energy offers into SPD should be with the exacerbator. Nova thought it would be reasonable for intermittent generators to pay for at least a proportion of frequency keeping costs on a pro-rata basis depending on the accuracy of their energy offers into the market. This would appropriately address scale issues and provide a link between costs and benefits. Demand should also contribute to the cost of frequency keeping. Under a centralised forecasting model, the incentive and penalties should only be considered once the performance outcomes of the centralised forecast can be duly assessed, as there may be diminishing returns in including them in up-front. Nova suggested any incentives could be included in the system operator's performance contract. The size and type of penalties would then be reflected in price for the system operator's contract (ie, higher penalties are likely to equate to a higher contract cost). Nova thought that any penalties would need to be carefully prescribed and defined as they will have a direct economic cost and should be related to tracking error rather than specific events or deviation. The penalties would also need to be symmetrical, and the net error factor (plus & minus) should track close to zero.
Transpower	Transpower thought well-designed incentives and penalties will deliver the best outcomes. A key aspect of the design of the incentives and penalties scheme will be having a suitable yardstick to measure accuracy will be important. Transpower noted there will be unavoidable inaccuracy in any forecasting exercise, therefore an incentive and penalty scheme could be based on comparison of forecasts with another forecast (rather than simply against actual outputs) – eg, what accuracy level was demonstrably possible? Under such an approach, an alternate (centralised) intermittent generation forecast would need to be available for the comparison to take place. Under a decentralised arrangement, Transpower suggested that assigning ancillary service costs on a causer pays model is one option (note a 'causer pays' model would apply to all causers, not just intermittent generators). This would apply to frequency keeping costs and to the proposed "new integrated ancillary service to offset increased uncertainty in net demand". Costs could be allocated on a pro-rata causer pays basis, incentivising accurate intermittent generation offers to minimise costs. To avoid the split-incentive of under-forecasting and over-delivering, intermittent generators' actual output could be limited to within a defined percentage of their forecast offer. Compliance repercussions could also be in place.

Submitter	Comment
	Under a centralised arrangement, Transpower noted that vendors of these services will have existing contracts which can for a start point for negotiation. Transpower also noted that having negotiated a load forecasting contract which includes accuracy provisions, it has relevant experience which may be helpful in this process.

Question 17: Who should have responsibility for submitting forecasts and who should pay for forecasting?

Submitters that responded

Submitter	Comment
Contact	Contact’s view was that intermittent generators should continue to have responsibility for submitting forecasts, even if this work is carried out by a central forecaster.
ETSI	ETSI’s view was that under a centralised arrangement, the cost of forecasting should be collected from all market participants via market fee recovery. Intermittent generators bear the cost of any decentralised forecasts, which requires an effective incentive and penalty scheme. ETSI disagreed with the Authority’s suggestion that the system operator would “turn off” the central forecast for an intermittent generator if the decentralised forecast provided for that intermittent generator was approved for use. ETSI thought the centralised forecast is critical to the design of the hybrid arrangement on the basis that it provides benchmarking for decentralised forecasts, and for system security purposes.
Genesis	Genesis’ view was that under a centralised arrangement, and in the absence of a self-forecasting option, Transpower or the Authority should be required to submit the forecast. Genesis thought the costs should be covered by intermittent generators based on their share of installed intermittent generation capacity (or expected yearly volume) with an associated forecast. For a decentralised forecasting arrangement, or in the case of a centralised arrangement with the option for self-forecasting in which the operator chooses to submit their own forecast, Genesis’ suggestion was for the intermittent generator to submit the forecast and cover the associated cost of producing it (as is currently the case) together with any penalties or charges relating to forecasting inaccuracies.
Helios	Helios’ view was that under a centralised arrangement, a ‘market cost’ approach that is allocated across all intermittent generators should be adopted. As the market learns and optimises its forecasting system, it might be appropriate to move to a ‘causer pays’ approach. Helios thought that a hybrid arrangement may encourage more self-forecasting if a causer-pays approach is adopted. This may result in lower costs for all generators (assuming lower CAPEX of a centralised system is achievable).
Lodestone	Lodestone thought the most cost-efficient solution would be to centralise the forecasting. Lodestone thought the recovery of the cost should be done on a per MWh basis rather than per participant basis as that would level the playing field between small and large generators.
Mercury	Mercury’s view was that under a centralised arrangement, intermittent generators should contribute to the costs of the forecast on a $/MWh basis. Alternatively, under a hybrid arrangement, intermittent generators who are able to do their own forecasts should

Submitter	Comment
	contribute to the cost of the centralised forecast if their forecasts are not as accurate as the centralised forecast. This would create a competitive tension and incentive for market participants to improve the quality of their forecast.
Meridian	Meridian's view was that under a centralised arrangement, users of the forecasting services should contribute to the costs. Meridian also thought forecast information should be provided directly to generators.
MEUG	MEUG did not support any option that socialises the costs of centralised wind forecast across all market participants. In MEUG's view, each type of generation should be responsible for the costs of its own forecasting requirements and these costs should be factored into the generators' offers into the market.
NewPower	NewPower suggested that forecasting costs should be applied by way of fees or levies, rather than being borne solely by intermittent generators. The other contributor to peaks is the load forecast, which is performed by the system operator. The cost of this should be spread across the industry via fees/levies, so NewPower's view was that applying a similar approach to generation forecasting keeps consistency.
Nova	Nova's view was that intermittent generators should pay for forecasts as they create the need for it (ie, consistent with the exacerbator pays principle). Given the system operator is already responsible for the centralised demand-side load forecasts applicable for all offtake market nodes, and intermittent generator forecasts will become more critical for meeting its Principal Performance Objectives, Nova suggested they could be responsible for submitting generation forecasts. Nova's view was that under a decentralised arrangement, generators should be required to submit offers to generate, not forecasts. The important difference under this model is that the system operator should not have to make any changes to its operating system in order to accept energy offers from intermittent generators.
Transpower	Transpower's view was that intermittent generators should submit offers rather than forecasts. If a centralised forecast is pursued, Transpower thought that forecast should be made available to intermittent generators to update their own offers reflecting plant unavailability and their offer prices. Transpower thought centralised forecasts should be paid for by intermittent generators, but noted materiality and practicality would need to be considered.

Question 18: What types of information should be published and what platform should it be published on?

Submitters that responded

Submitter	Comment
Contact	Contact's view was that all wind generation should be published, and all imbedded generation should be published if an individual generator has more than 1MW of capacity.
ETSI	ETSI's view was that all forecasts used in any power system functions and processes (including confidence intervals) should be published. ETSI suggested that delaying the publication of the individually identifiable forecasts could address commercial confidentiality issues. ETSI suggested information should be published via an interactive dashboard as well as via an API.
Genesis	Genesis' view was that it would be useful to have an idea of distribution/uncertainty (eg, a P25/P75 or P10/P90 forecast for the whole horizon) in addition to the submitted P50/expected forecast. Genesis noted that providers such as Meteologica or MetService can already provide uncertainty measures. Under a hybrid arrangement, intermittent generators who produce their own forecasts could be required to provide these uncertainty measures.
Helios	Helios suggested that information be published on WITS, although it did not specify the type of information it thought should be published.
Lodestone	Lodestone suggested that an aggregated wind and solar generation forecast by island should be published (similar to the one that has been established for North Island wind on EM6).
Mercury	Mercury thought that forecasts should be at the national, island and regional level. but not show forecasts for individual wind farms. Mercury suggested that this information should be published on WITS.
Meridian	Meridian acknowledged that some information might be commercially sensitive (eg, data inputs provided by intermittent generators), and that the Authority should place appropriate safeguards to prevent this information being published.
NewPower	NewPower thought information should be easily accessible and able to incorporate into systems for dispatchable generation (eg, via an API). NewPower recommended that network demand forecasting be included in the same dataset, including distributed generation forecasts so that a net grid demand position is included to provide better visibility of demand growth and seasonal profiles.
Nova	Nova suggested that under a centralised arrangement, the forecast information should be shared via either the generator's default energy offer (subject to the generator notifying the forecaster or system operator of any adjustments to capacity due to maintenance) or

Submitter	Comment
	shared with the relevant intermittent generator for it to then submit its offer based on the forecast. Nova suggested that if the central forecaster was to provide forecast data only this can be centrally published on existing platforms. Under a decentralised arrangement, Nova suggested the existing pricing schedules with scheduling, pricing, and dispatch runs would perform the task of projecting generation requirements and market prices.
Transpower	Transpower's view was that confidence intervals (or the range of an intermittent generation forecast) should be published. It noted this would be easier under a centralised arrangement. Under a decentralised arrangement, individual intermittent generators would have to provide this information separately to their offers.

Appendix C: Updated assessment of each option against the evaluation criteria

Evaluation criteria → **Options ↓**	Efficiency	Reliability	Enhances competition	Affordability	Practicability	**Overall assessment**
Status quo	Medium (2)	Low (1)	Medium (2)	Medium (2)	Low (1)	**8**
Decentralised arrangement with incentives/ standards	Medium (2)	Medium (2)	Medium (2)	Medium (2)	Medium (2)	**10**
Centralised arrangement	Medium (2)	High (3)	Medium (2)	High (3)	High (3)	**13**
Centralised arrangement with option for self-forecasting (hybrid)	High (3)	High (3)	High (3)	High (3)	High (3)	**15**
Ahead and balancing market	Medium (2)	High (3)	Medium (2)	Low (1)	Medium (2)	**10**

Key:
- High = 3 points
- Medium = 2 points
- Low = 1 point

In the Authority's view, the hybrid arrangement would have greater efficiency benefits as under this arrangement, generators would be better incentivised to be innovative. This could lead to better accuracy compared to the centralised forecast. The hybrid arrangement would most effectively enhance competition as it could create competitive tension between centralised forecasting and self-forecasting approaches. This could improve the quality of both approaches.

The 'decentralised forecasting arrangement with incentives/standards' option received a 'medium' score on each criterion. This reflects that it would be an improvement on the current arrangement, but in the Authority's view it would not deliver the same widespread benefits as the hybrid or centralised arrangements.

The 'ahead and balancing market' scored highly on the 'reliability' criterion, but it received lower scores on the other criteria. It scored the lowest on the 'affordability' criterion to reflect that implementing an ahead and balancing market would be a significant undertaking that would require structural changes to the electricity market.

Assessment of benefits for intermittent generation forecasting

14 May 2024

concept consulting

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Contents

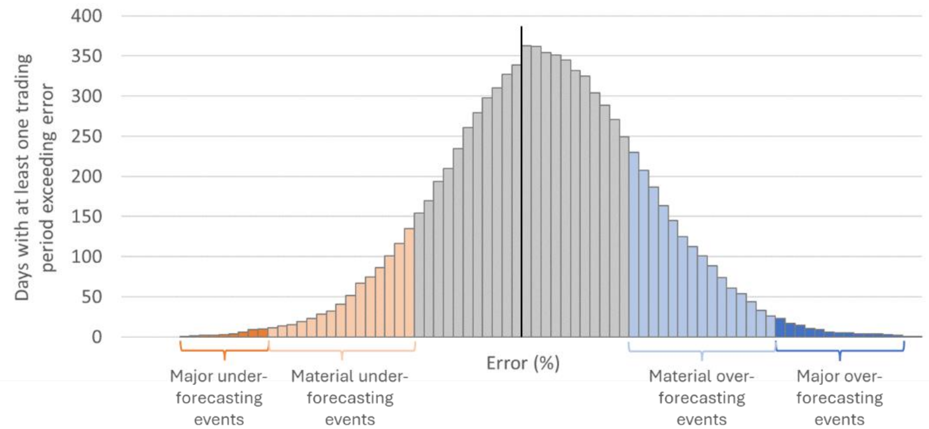
1 Executive summary

We estimate minimum benefits of $15.4m over five years ($3.1m per year) are available from moving to a central forecast and adopting forecast quality standards. We derive this estimate by comparing relative performance of currently available 'distributed' and 'central' forecasts. Annual benefits, which increase as wind generation grows, accrue principally from reducing:

- material or major over-forecasting events
- major under-forecasting events
- systematic bias in wind generation offers towards over-forecasting.

These benefits are represented on the diagram below:

Figure 1: Forecast error event distribution (2029 example)



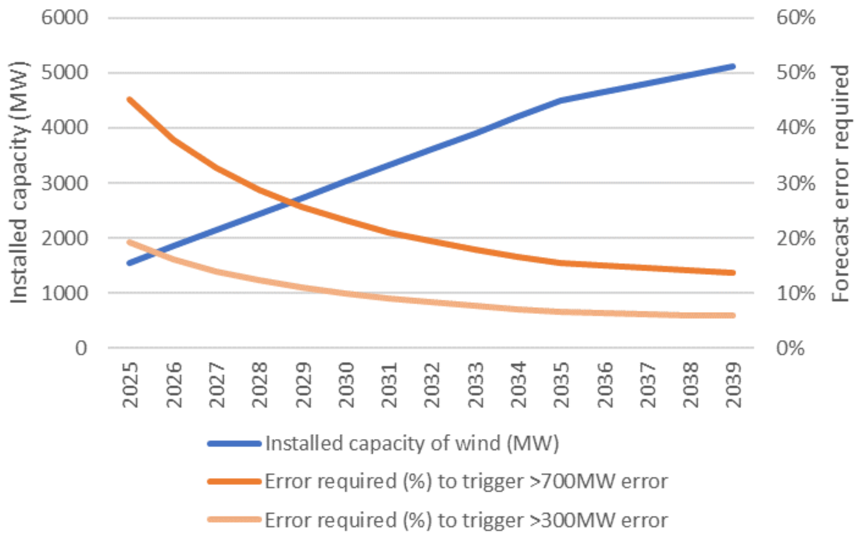
We assess the five-year present value (PV) of implementing the Authority's proposal as in a range from $15.4m to $33.9m. The fifteen-year present value is assessed as in a range from $151.5m to $326.5m.

Table 1: Economic benefits – base case and sensitivity analyses ($m, five-year PV)

Base case	30.7
Forecasts adjusted for bias	21.0
Cheaper flexible generation preparation costs	32.8
Slower growth in wind generation capacity	21.7
Higher de-rating factor	15.4
Closer decision point (6 hours ahead)	33.9

The increase in benefits over time is primarily due to the expected increase in wind generation, which is forecast to approximately treble by 2033. The effect of this is to reduce the size of forecast error required (in percentage terms) to cause a material or major under-forecasting or over-forecasting event. This is illustrated on the diagram below.

Figure 2: Percentage error required to trigger forecast error event



The longer-term benefits are affected by factors such as:

- the quantity and geographic location (diversity) for wind generation
- the quantity, cost and location of stored energy and demand side resources

We address these uncertainties where possible through sensitivity analysis, and identify no scenario where benefits fall below a PV of $15.4m over five years ($3.1 million per annum) and a PV of $151.5m over fifteen years ($10.1 million per annum).

We consider there are additional non-quantified benefits for electricity consumers. These benefits accrue principally from:

- **lower and less 'peaky' energy prices** – which reduce inefficient demand management action and investment by consumers, and affect retail market competition

- **reducing the need for 'work-arounds'** – to overcome wind-forecast deficiencies, avoiding direct and indirect (opportunity) costs of these activities.

- **avoided generator forecast costs –** generators have the opportunity to utilise centrally provided wind forecasts in place of self-procured forecast data.

While we do not estimate benefits for centralised solar forecasts in this analysis, a similar approach could be undertaken when information is available. We would expect benefits to arise for similar reasons (fewer material or major over-forecasting and under-forecasting events).

We do not estimate the costs of implementing centralised wind-forecasting however we note that wind forecasts are currently prepared by wind-generators for each location and the System Operator for all locations.

2 Background and context

At present all generators are required to provide offers that should reflect expected plant capacity, outages and fuel availability. For wind generators, these offers must include a forecast of generation potential (FOGP).

As previous analysis by the Authority has shown, there is a marked difference in the accuracy of forecasts between generators.[1] We understand this is because some generators procure and use higher-quality wind forecasts when preparing offers, while others do not. There is a clear opportunity to improve wind forecast quality (and offer accuracy) by bringing poorer performing forecasts up to a similar level as the best performing forecasts. This opportunity is recognised and appears to have broad support of participants based on submissions.

We note that Transpower as the System Operator (SO) already procures a wind generation forecast. Some of this information is published on the em6 website, showing forecast wind generation (including 10th, 50th and 90th percentile projections) and comparing this to FOGPs across the next 36 hours.[2] However, we understand that forecasts for individual wind farms are not provided to wind generators, so wind generators must still base FOGPs on their own decentralised forecasts. As such, we do not consider this a true 'centralised forecast'.

Due to relative infancy of New Zealand's grid-connected solar generation, this report focuses on quantifying the gross benefits of a centralised forecasting arrangement for wind generation only. In the future we expect the system to have a high installed capacity of grid-connected solar generation also. We expect there would be benefits of a centralised solar forecast, but as solar in New Zealand is still in its infancy, we are unable to quantify these at present. We expect they would be relatively small initially, reflecting the small installed capacity of at present, but that they would increase with the growth of solar generation. As with wind, we expect these benefits to increase in a non-linear manner. We discuss the likely gross benefits of a centralised solar forecast qualitatively at section 11.

[1] See section 3 of Accuracy of Wind and Load Forecasts (ea.govt.nz).
[2] Aggregated generation for North Island wind farms only. See Electricity Market Overview (em6.co.nz).

3 Problem definition

Less accurate wind forecasts flow into wind generation offers that are too high or too low. Historically, the 12-hour ahead FOGP has been wrong by as much as 40% of installed wind capacity, around 500MW based on the current installed capacity of wind generation. The SO produces forecast schedules with prices and quantities based on FOGPs (amongst other inputs), so less accurate wind FOGPs reduce the accuracy of these forecast schedules.

Many operators of flexible resources[3] make operational decisions that require some kind of prior notice. For example, before they can start operating:

- slow-start thermal generators may need time to warm up plant
- hydro generators may need time to move water from storage lakes to generation head ponds
- battery operators may need warning to charge and prepare batteries
- demand response providers may need time to prepare load curtailment or ramp-up capability.

Prior notice is signalled through the forecast schedules produced by the SO. Poorer quality information in these forecasts will reduce decision quality by operators of flexible resources.

Figure 3: Logic chain of current problem

[3] We use the term 'flexible' to refer to generation and other resources where the level of output can be controlled (as opposed to must-run or intermittent generation). This includes both slow-start and short-notice resources.

These impaired decisions result in the two key kinds of economic costs (outlined below), which we quantify in this analysis.

We expect inaccurate solar forecasting will have similar effects when it makes up a more substantial proportion of New Zealand's generation capacity.

3.1 Dispatch of more expensive resources

Over-forecasting wind leads to FOGPs that are too high. This results in forecast schedules with higher generation and lower prices than will actually occur. Flexible resource providers conclude that less or no response is required, and therefore do not warm up generators or take other preparatory steps.

When less wind than expected arrives in the lead up to real time, more expensive resources must be dispatched to avoid a generation shortfall, as cheaper resources are unavailable at short notice. In extreme cases, this may include involuntary load-shedding.

3.2 Unnecessary preparation costs

Under-forecasting wind leads to FOGPs that are too low, resulting in forecast schedules with lower generation and higher prices than will actually occur. These higher prices signal that more flexible resource will need to be dispatched, so operators of these resources will prepare to operate. When more wind than expected arrives in the lead up to real time, it displaces those resources. As a result, the unnecessary preparation results in economic costs to New Zealand (e.g. wasted start-up costs, fuel, spill of water, etc.).

3.3 Other economic costs not quantified in this analysis

Impaired decision making by operators of flexible resources also results in other costs which are harder to quantify than those described above. We do not include these in our quantitative analysis, but we set them out below to illustrate that our assessment of benefits is likely a lower side estimate.

- **Higher clearing prices** – the dispatch of more expensive resources (as described in the first point above) results in higher spot prices on average over time. While our analysis is focused on economic costs to New Zealand as a whole (rather than price impacts or wealth transfers), higher electricity prices over time may increase the risk of energy hardship for consumers[4] and lead to inefficient energy consumption and investment choices. Higher average and more volatile or 'peakier' prices will affect generation investment choices (the quantity and type of generation).
- **Increased system operation costs** – under current arrangements, the SO needs to find 'work arounds' to manage the elevated risk from persistently and at times materially inaccurate forecasts. The SO must procure additional resource (both energy and reserves) at short notice, when accurate forecast schedules at an earlier stage could have signalled lower-cost resources to be available. This results in higher costs and increased complexity for the SO.
- **Generator forecasting costs** – generators currently procure or develop their own forecasts, which incurs costs. Under the Authority's proposal, as generators will be able to rely on the centralised forecast they may avoid the cost of purchasing wind

[4] The Authority has an additional statutory objective "to protect the interests of domestic consumers and small business consumers in relation to the supply of electricity to those consumers".

forecast data. We note generators may incur costs to incorporate the centralised forecasts into their FOGP.

4 The proposal

The Authority is proposing implementing a hybrid arrangement where wind generators base their FOGPs on either:

- a centralised wind generation forecast procured by the SO, or
- forecasts they have procured or developed themselves (if they can demonstrate that these are at least as accurate as the centralised forecast).

For this analysis, we assess the benefits of a simplified version of this proposal where generators' own forecasts have the same level of accuracy as the centralised forecast (effectively the same result as if all generators based their FOGPs on the centralised forecast). We note that this is likely to be a lower bound of the benefits of the Authority's proposal, as a hybrid arrangement would likely further improve forecasting accuracy.

The Authority is also considering implementing accuracy standards to incentivise more accurate forecasting from wind generators and other parties.

The precise details of the relationship between a centralised forecast and accuracy standards were still in development at the time of analysis – as such, we set out below the key characteristics we have assumed for both the proposal and status quo counterfactual.

Table 2: Differences between proposal and counterfactual

	Proposal (i.e. implementation of centralised forecast)	**Counterfactual (i.e. continuation of status quo)**
Is there a centralised forecast?	Yes. We assume a centralised forecast (including forecasts for each individual wind farm) will be procured and provided to wind farm operators. We assume that this centralised forecast will be at least as accurate as the forecast currently procured by SO.	No. While we assume the SO will continue to procure a wind generation forecast as discussed above, we do not consider this to be a centralised forecast as individual wind farm forecasts are not provided to wind farm operators, so this forecast is not reflected in FOGPs or resulting forecast schedules.
Do wind generators procure or develop their own forecasts?	Mixed. We assume that fewer generators will procure/develop their own forecasts as they will be provided with a centralised forecast, though some may continue to do so. Our analysis assumes these forecasts have the same accuracy as the centralised forecast (effectively producing the same results as if all wind generators used the centralised forecast).	Yes. We assume that generators will continue to submit their FOGP based on their own forecasts (although in theory, generators could submit a FOGP not based on any forecast until two hours before gate closure, where the Code requires them to submit a forecast based on a persistence model).
Are there accuracy standards in place?	Yes. We assume there will be standards in place that incentivise: • the provider of the centralised forecast to ensure it is at least as	No. We assume there will continue to be no standards in the Code that incentivise accurate forecasting of wind generation,[5] and that as a result FOGPs will continue to be

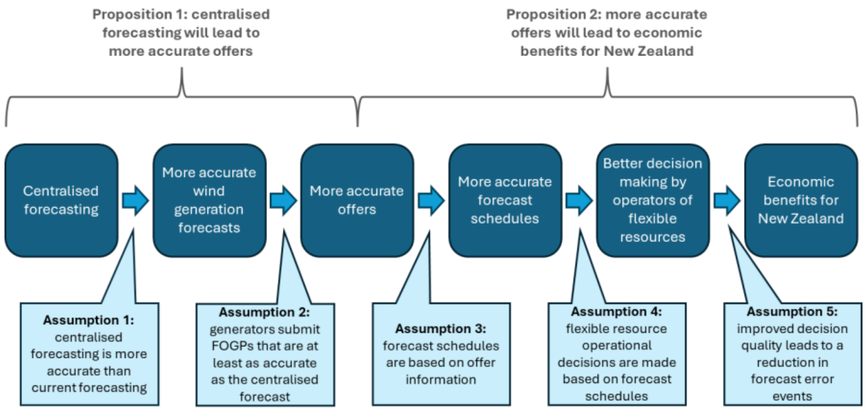
[5] Currently if an individual plant generates 30MW below the FOGP in their final offer, the wind generator must submit a report to the Authority, but this is not accompanied by any financial penalty or other substantive incentive. Incentives may still arise due to other factors, e.g. generators trying to balance their retail book using flexible generation, but these may be weaker, or absent, for generation output sold under a power purchase agreement with a fixed price and variable volume.

	accurate as the forecast procured by the SO • wind generators to ensure they base their FOGPs on the centralised (or other more accurate) forecast • wind generators procuring/ developing their own forecasts to ensure these are at least as accurate as the centralised forecast.	as accurate in the future as they are now (in percentage terms).
Who submits generation offer quantities for each wind farm?	Generator (same as status quo). The Authority has considered implementing a system where FOGPs are automatically populated based on the centralised forecast. However, due to feedback from the SO that this would require complex and expensive changes to their system, we assume that generators will continue to submit their own FOGPs as before.	Generators. We assume generators will continue to submit their own FOGP as part of the offer process.
What visibility do providers of flexible resources have of forecast wind generation?	Same as status quo (see next column).	Flexible resource operators will continue to have access to forecast wind generation for North Island wind farms over the next 36 hours, based on the forecast procured by the SO. The SO may also occasionally advise these parties of additional information about expected wind generation to aid decision making.

5 Logic chain

The following logic chain shows how a centralised forecast is expected to produce economic benefits for New Zealand, relative to the status quo. It is based on reducing the economic costs associated with less accurate forecasting as discussed in section 3 above – as such, the diagram below is largely the inverse of Figure 3.

Figure 4: Logic chain of proposal impact



We expect a proposal to introduce centralised solar forecasting to have similar impacts once solar generation makes up a larger proportion of New Zealand's generation capacity.

We have broken this logic chain down into two key propositions. In the following section we describe the evidence to support these propositions and the assumptions underpinning them.

5.1 Proposition 1: centralised forecasting will lead to more accurate offers

Under the status quo, offers are less accurate because either:

- they are based on less accurate wind forecasts, or
- wind generators do not convert wind speed forecasts into accurate offers.

Therefore, for a centralised forecast to improve offer accuracy, the following must be true:

- Assumption 1: centralised forecasting is more accurate than decentralised forecasting in the future, and

- Assumption 2: wind generators submit FOGPs that are at least as accurate as the centralised forecast.

Assumption 1:

We assume that both the centralised and decentralised forecast will have the same level of accuracy (in percentage terms) as the same kind of forecasts have had in recent history.[6] We therefore use the following historical forecast data as a proxy for the error distribution in the future.

Table 3: Proxies used for future forecast error distributions

	Centralised	Decentralised
We use the historical error distribution of:	the forecast procured by the SO (aggregated for North Island wind generation) from December 2022 to March 2024 (inclusive).	FOGPs (aggregated for North Island wind generation) from December 2022 to March 2024 (inclusive).
To represent the future error distribution of:	the hypothetical centralised wind generation forecast (aggregated for all New Zealand wind generation) that would be procured under the Authority's proposal.	the decentralised wind forecasts (aggregated for all New Zealand wind generation) on which wind generators would base their FOGPs.

We do not have data on the accuracy of current decentralised wind forecasts on which wind generators base their FOGPs, but we do have data for the 6-hour and 12-hour ahead FOGPs.[7] We consider it reasonable to assume that a centralised forecast will be more accurate than the average decentralised forecast, as our analysis shows that the forecast currently procured by the SO for wind generation in the North Island is substantially more accurate than FOGPs (which are based on decentralised forecasts), at both 6 and 12 hours ahead of dispatch.

We note that the accuracy of FOGPs may degrade in future, if forecast quality incentives for the operators of new wind generation are weaker or absent (for example, where power purchase agreements with fixed price and variable output apply). This may be offset by greater diversity from a wider range of forecasters.

Assumption 2:

We assume that wind generators submit FOGPs that are based on the centralised forecast (or on their own forecasts with the same level of accuracy). This assumption is based on the Authority's plan to introduce accuracy standards. While the policy details of the Authority's proposal are not fully developed, discussions with the Authority indicated that these standards will ensure that wind generators' do not make the centralised forecast any less accurate when they convert it to a FOGP. This could be through process standards (i.e. ensuring that wind generators may only amend the centralised forecast in certain ways or for particular reasons) or substantive standards (i.e. penalising generators if their FOGP is less accurate than the centralised forecast they were provided with).

5.2 Proposition 2: more accurate offers will lead to economic benefits for New Zealand

For more accurate offers to result in economic benefits (through avoiding economic costs), we must assume that:

- Assumption 3: forecast schedules (prices and quantities) are based on offer information
- Assumption 4: flexible resource operational decisions are made based on forecast prices and quantities, and
- Assumption 5: improved decision quality leads to a reduction in forecast error events.

Assumption 3:

[6] We note that the centralised forecast may draw on multiple forecasts or data sources which may result in a more accurate central forecast than is assumed in this analysis.

[7] On aggregate for all North Island wind farms. South Island wind farms have been excluded from the analysis as they are not included in the publicly available forecast currently procured by the System Operator.

The SO publishes several schedules that include forecast prices and quantities over various time horizons. The latest intermittent generation offers are one of the inputs into the model that creates these schedules (alongside offers from other generators, load forecasts, constraints, ramp rates, reserve requirements, and other inputs).[8]

It is therefore reasonable to assume that the FOGPs submitted by wind generators influence forecast schedules. While other inputs also affect forecast schedules, the only input that will change between the status quo and the Authority's proposal will be the accuracy of FOGPs.

Assumption 4:

In general, operational decisions will be made based on forecast schedules. When forecast schedules indicate lower generation and higher prices, additional flexible resource is:

- more likely to be needed to balance supply and demand
- more likely to be able to recover its costs
- therefore more likely to be prepared for generation (and vice versa).

However, there may be some instances where operators of flexible resources may base their decisions on additional factors. For example, a flexible resource operator may:

- be contacted by the SO directly to advise that it expects wind to be higher or lower than indicated by forecast schedules
- have an asymmetric view of risk, and therefore have a tendency to prepare flexible resources when the economic case for doing so may be marginal
- already be preparing or operating the resource, and therefore not require as much time to prepare the resource before real time
- have received other sources of information that FOGPs/forecast schedules will not reflect actual wind generation (such as the North Island wind forecast procured by the SO and published on the em6 website).

However, we expect operational decisions will be predominantly based on forecast schedules. We also think this is likely to be particularly true in later years as the electricity system becomes more distributed and automated. This will lead to more, smaller resources that make decisions based on algorithms, rather than fewer larger resources where more manual decisions are made based on a wider range of factors.

Assumption 5:

There may also be instances when impaired preparation decisions (due to inaccurate forecast schedules) do not have significant economic impacts. This could occur if the forecast errors occur at times of low demand (for over-forecasting events) or high demand (for under-forecasting events) demand.

However, we expect that in the future flexibility resources will be optimised to meet the forecast supply demand balance, potentially leaving few resources available for if this balance changes within several hours of real time. For example, even if there are many more grid-connected batteries on the system, if forecast schedules suggest prices will be low, operators may run these batteries low, so that when a generation shortfall arises they cannot respond in time.

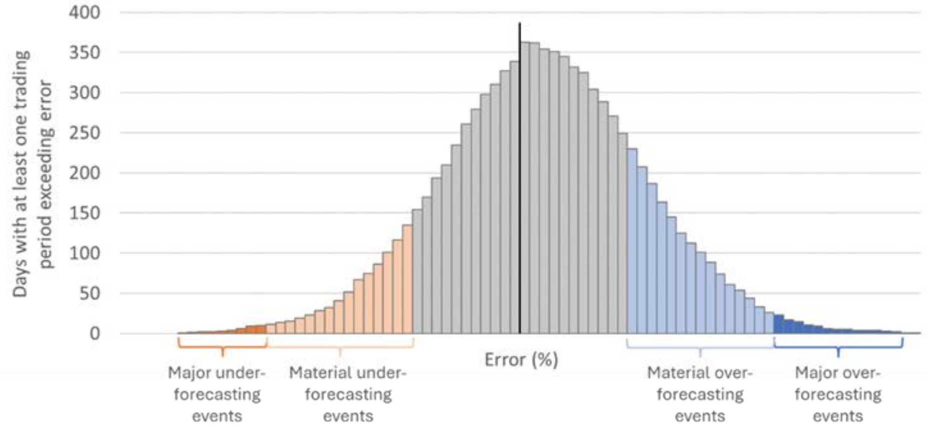
6 Methodology

The level of economic costs from errors will depend on their sign (positive or negative), size and frequency. As shown in Figure 5 below, most FOGPs have a relatively small error when expressed as a percentage of installed wind generation capacity. However, any degree of wind forecasting errors can result in some change to price forecasts, and therefore affect the quality of decision making. Even a small under-forecasting error can lead to some unnecessary resource preparation

[8] See SPD Schedule Inputs (transpower.com).

costs, and a small over-forecasting error can lead to a slightly more expensive combination of resources being scheduled.

Figure 5: Forecast error event distribution (2029 example)



However, for the purpose of this analysis we have assumed that 'smaller' (in MW terms) errors are costless (a conservative assumption). Instead, we have focused on larger 'forecasting error events' that occur when errors are greater than 300MW.

The four 'forecasting error events' used in this analysis are:

- **Material over-forecasting event** – a day with at least one hour where the average forecast wind generation is between 300MW and 700MW higher than actual generation.
- **Major over-forecasting event** – a day with at least one hour where the average forecast wind generation is more than 700MW higher than actual generation.
- **Material under-forecasting event** – a day with at least one hour where the average forecast wind generation is between 300MW and 700MW lower than actual generation.
- **Major under-forecasting event** – a day with at least one hour where the average forecast wind generation is at more than 700MW lower than actual generation.

We note that based on current installed capacity of wind generation, events these sizes are unlikely to occur often. However, as discussed below, when installed wind capacity grows, events of these sizes begin to occur more frequently.

6.1 Summary of steps

For each type of forecasting error event, and each year:

1. **Calculate percentage error threshold** – this is error size (expressed as a percentage of installed capacity) that would trigger the forecasting error event (a fixed MW figure). This percentage error threshold will get smaller as more wind generation capacity is built each year.
2. **Calculate number of expected forecast error events** – this is the number of days per year with at least one hour that has an average error exceeding the percentage error threshold calculated above. This needs to be calculated for both the status quo (based on the historical error rates of FOGP offers) and the Authority's proposal (based on the historical error rates of the forecast procured by the SO).
3. **Calculate reduction in forecast error events** – this shows the improvement (or worsening, as the case may be) in the number of forecast error events that are likely to occur that year as a result of the Authority's proposal, compared to the status quo.
4. **Apply de-rating factor** – this represents that in practice, a proportion of these forecast error events will not result in poor decisions by flexible resource operators, and that not all poor decisions will result in economic impacts.
5. **Multiply by economic cost per event** – this shows the avoided economic cost from each type of forecasting error event per year as a result of the Authority's proposal.

Then:

6. **Sum the benefits for each event** – this shows the total avoided economic costs from all four types of forecasting error events for each year.
7. **Apply 5% discount rate** – this produces a present value of the expected avoided economic costs (i.e. economic benefits) over a 5-year time period.

We discuss the assumptions underlying these steps below.

6.2 Growth of installed wind capacity

To estimate the amount that installed wind generation capacity is expected grow over the next few decades, we used actual capacity in 2024, as well as the figures produced for 2035 and 2050 in modelling for the Market Development Advisory Group's (MDAG) final recommendations paper for their Pricing in a Renewables-based Electricity System project.[9]

We assumed linear growth between these dates.

6.3 Forecast error events

Our assessment considers how many times these events are likely to occur per year into the future under the status quo, and how many fewer (or more) events are likely to occur per year if the centralised forecast is implemented. This is based on the error (expressed as a percentage of the expected installed capacity for that year) required to cause the event.

For example, in 2029 (year 5 of the CBA) we expect installed wind capacity to have grown to 2729 MW. At this level of capacity, it would take a 26% over-forecasting error to trigger a 700MW shortfall of generation in real time. Based on the historical accuracy of decentralised forecasting arrangements (see Figure 5 above), there would be 22.5 days per year that would have at least one hour with an average over-forecasting error of at least 26%. However, under centralised forecasting arrangements, this would only occur on 7.5 days per year (i.e. 15 fewer days per year).

[9] Some adjustments were made to account for the assumption that the Tiwai Point aluminium smelter is expected to remain throughout the entire timeframe (MDAG projections assumed a smelter closure). Original projections were in GWh/yr, which we converted to MW using a capacity factor of 39.4%.

In converting the number of days that meet the percentage error threshold into the number, duration and size of forecast error events, we have conservatively assumed:

- each type of forecast error event can only occur once per day, even though there may be multiple hours in that day with errors that exceed the error threshold. This means preparation costs can only be incurred once per day
- over-forecasting events (i.e. unexpected shortages) have a duration of one hour, even though there may be multiple consecutive hours in that day with errors that exceed this threshold
- over-forecasting events are the minimum size needed to trigger that event. For example, a major over-forecasting event will require exactly 700MW of short-notice capacity (even though the forecast error could be larger than 700MW).

6.4 De-rating factor

We apply a de-rating factor of 50% to the number of forecast error events. This represents the imperfect correlation between both:

- less accurate forecast schedules and impaired operational decision making
- impaired operational decision making and economic impacts

As previously discussed, there will be instances where flexible resources' operational decision making is not made worse by wind generators submitting inaccurate FOGPs, as well as instances where the system can be operated without significant economic impacts despite the material or major forecast error event.

We also include a sensitivity case where a greater de-rating of 75% is used – in that case we essentially only quantify the economic impacts of one quarter of the total forecast error events (i.e. half the forecast error events we quantify in the base case).

6.5 Estimating cost of each forecast error event

We multiply the de-rated expected number of reductions (or increases) in forecast error events per year by the expected cost of each event to calculate the avoided (or additional) economic costs resulting from the proposal for each year.

For each type of event, we assume that every occurrence incurs the costs outlined in the table below.

Table 4: Cost assumptions

Event type	Nominal size (MW)	Duration (hours)	Cost per event ($)
Major over-forecasting (>700MW)	700	1	1,472,500
Material over-forecasting (300-700MW)	300	1	82,500
Major under-forecasting (>700MW)	700	1	262,500
Material under-forecasting (300-700MW)	300	1	112,500

Over-forecasting events

The cost of each major and material over-forecasting event (i.e. when there is an unexpected wind generation shortfall) will be managed by calling upon resources that require no prior notification.

We have assumed that the resources available and their costs are as follows:

- **Voluntary short-notice demand response** – we assume that there is 500MW of short-run demand response available in three price tranches. The first 200MW is available at $700/MWh, the next 150MW is available at $1,000/MWh, and the remaining 150MW is available at $1,500/MWh.[10]
- **Reduced reserve cover** – we assume that the SO will be willing to reduce reserve cover by 100MW to manage major over-forecasting events. The first 50MW is available at a cost of $3,000/MWh and the remaining 50MW is available at $3,500/MWh.[11]
- **Involuntary load shedding** – we assume that any further capacity can be met by involuntary load shedding (including of general residential load) at a price of $10,000/MWh.[12]

As previously mentioned, we assume major over-forecasting events will require 700MW of short-notice capacity for one hour (i.e. all types of resources described above). We assume material over-forecasting events will require 300MW of capacity for one hour, which can be met by the first two tranches of voluntary short-notice demand response.

If the over-forecast error event had not occurred, we assume the unexpected shortfall could have been avoided by preparing 'slow start' resources. We assume that an unlimited number of these resource units are available, with each unit having the following characteristics:[13]

- 200MW capacity
- Start-up costs of $75,000 per resource per event
- Running costs of $150/MWh

A major over-forecasting event will avoid preparation and running costs for 1.5 units of the slow-start resource, while a material over-forecasting event will avoid costs for 3.5 units. We therefore subtract the cost of preparing and running these slow-start resources from the cost of the short-notice resources to get the net cost for each over-forecasting event.

We assume these costs outlined above are unaffected by any transmission factors (i.e. that losses and constraints would have the same effect on short-notice resources, slow-start resources, and wind generation).

[10] This is based on assumptions used in the MDAG's modelling – see slide 108 of Price Discovery with 100% Renewable Electricity Supply - final simulation assumptions and results (ea.govt.nz).

[11] This is based on clause 13.58AA(3) of Part 13 of the Code, which set out the values the SO must assume for sustained instantaneous reserve contingent risk violation.

[12] This is based on clause 13.58AA(2) of Part 13 of the Code, which set out the values the SO must assume for the first 5% of unsupplied demand.

[13] These assumptions are based on the hypothetical slow-start unit considered by the Authority at paragraphs 4.19-4.20 of Driving efficient solutions to promote consumer interests through winter 2023 (ea.govt.nz).

Under-forecasting events

The cost of each under-forecasting event (i.e. when there is an unexpected surplus of wind generation) will manifest in unnecessary preparation costs being incurred by the 'slow-start' resources described above. A major under-forecasting event will incur preparation costs for 1.5 units of the slow-start resource, while a material under-forecasting event will incur preparation costs for 3.5 units.

6.6 Discount rate and present value

We use a 5% discount rate[14] to calculate the present value of these economic benefits over a five-year timeframe from 2025 to 2029 (i.e. assuming that the proposal is implemented by the end of 2024).

We use a five-year period because the rate of change in the electricity sector means that there is significant uncertainty as to what the sector will look like beyond the end of the decade. In particular, the make-up of flexible resources on the system is likely to change substantially as more thermal generation is retired and new flexible technologies become more prevalent. These new technologies will likely have different characteristics to current resources (particularly in relation to their costs and start-up times). This could affect our assumptions around how much over-forecasting and under-forecasting events are likely to cost.

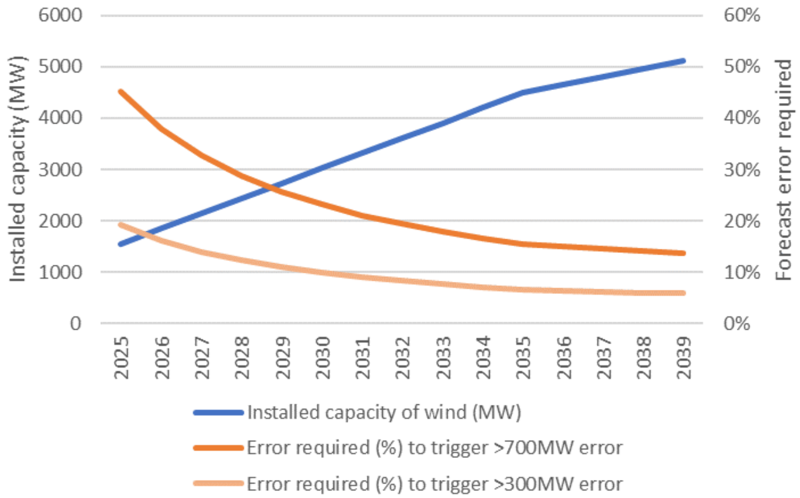
Under current assumptions, the present value of the benefits of the Authority's proposal over a longer period (for instance, fifteen years) will be substantially higher than the five-year present value. This is mostly because the large expected growth in wind generation will make major over-forecasting events (>700MW errors) much more common.

7 Findings

7.1 Effect of increase in wind generation over time

As shown in Figure 6, wind generation is expected to grow significantly to meet growing demand and thermal retirement. As a result, the percentage error in total wind generation forecasts necessary to trigger a material or major forecast error event reduces substantially.

Figure 6: Wind generation installed capacity



For example, we forecast there will be around 1,550MW of wind of the system in 2025, at which point a forecast error of 45% is required to trigger a 700MW forecasting error event. However, by 2039 when wind capacity is projected to be 5,100 MW, the forecast error needs only to be 14% of installed capacity to trigger the same event.

Forecast accuracy would need to improve significantly to keep within the accuracy band that would avoid triggering these events. Even more importantly, a small improvement in wind forecast quality will translate into a larger gain in MW forecast accuracy, simply because the installed wind capacity is growing over time.

Put simply, assuming the existing distribution of forecast errors (in percentage terms) under the status quo remains constant over time, the increase in wind capacity will lead to many more material and major forecast error events. For example, by 2039 we can expect material over-forecasting events or greater (i.e. more than 300MW) to occur on

[14] As recommended by Treasury – see Discount Rates (treasury.govt.nz).

approximately 325 days per year (89%) if decentralised forecasts continue to be used and forecast quality remains unchanged.

Even with a centralised forecast, the number of material and major forecast error events will increase substantially. However, we expect fewer forecasting errors to occur overall with a centralised forecast than would occur if the status quo continued.

7.2 Effect of current bias towards over-forecasting

Although total forecasting error events would reduce, interestingly we expect under-forecasting errors to become more prevalent under the centralised forecast than under the status quo – particularly in the later years. This is because FOGP offers tend to be biased towards over-forecasting (and therefore under-forecasts are less prevalent).

The mean errors across all hours in the analyses data were:

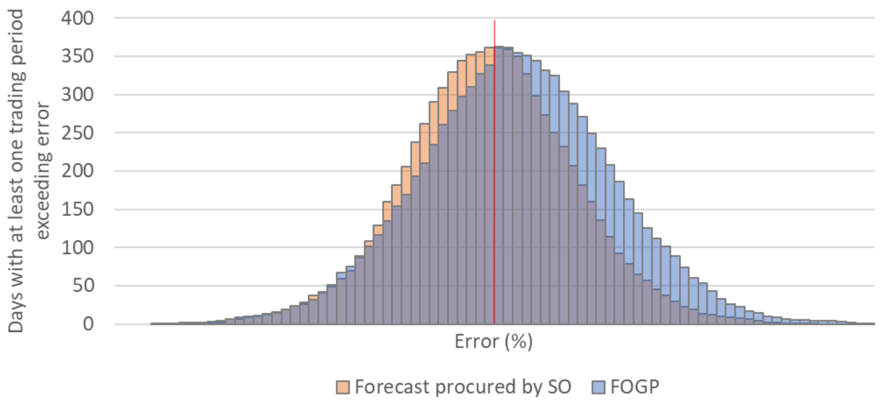
- -0.33% for the central forecast (i.e. a very small bias towards under-forecasting)
- 2.60% for FOGP offers (i.e. a more substantial bias towards over-forecasting).

This bias means that moving to a centralised forecast will result in:

- fewer over-forecasting error events (both major and material)
- more under-forecasting error events (of less than 13% of installed capacity, which becomes a sufficient threshold for material under-forecasting events by 2028).[15]

[15] There are a similar number of under-forecasting events of more than 13% of installed under the centralised and decentralised forecasts.

Figure 7: Error spread with bias



If we assume this bias is reliable then in theory the SO could adjust FOGPs by the average bias when it prepares forecast schedules. We have prepared a sensitivity analysis (see section 9.1) that considers the implications of this.

8 Results

The present value of economic benefits (i.e. avoided costs) over five years of reducing the number of forecasting error events through implementing a centralised forecast is $30.7 million, as outlined in the table below.

Table 5: Economic benefits - base case ($m, five-year PV)

Avoided costs of major over-forecasting events	19.4
Avoided costs of material over-forecasting events	13.0
Avoided costs of major under-forecasting events	0.1
Avoided costs of material under-forecasting events	-1.8
Total avoided costs of forecast error events	**30.7**

Most of these benefits come from avoiding over-forecasting events. This is partly due to the removal of the over-forecasting bias present in the decentralised forecast, as well as reducing the spread of errors. Major over-forecasting errors are the most expensive error events, so most economic benefits come from avoiding these events.

Moving to a centralised forecast will increase the number of major under-forecasting events, again largely due to the removal of the over-forecasting bias. However, as the cost of major under-forecasting events tends to be lower than the cost of major over-forecasting events, moving to a centralised forecast still avoids economic costs from forecasting error events overall.

Average annual benefits increase substantially when the present value over a longer timeframe is used – for example, benefits total $303 million over a fifteen-year period ($20.2 million per year). However, as discussed above in section 6.6, we consider a five-year PV is a better conservative timeframe.

9 Sensitivity analyses

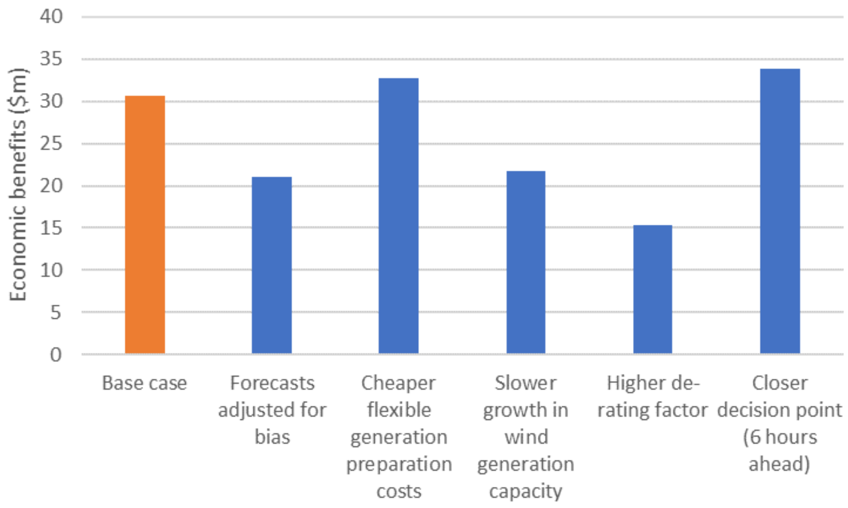
The results above are for the base case. However, we have also run the analysis for several other scenarios to test the sensitivity of our results to changes in key assumptions.

Table 6: Economic benefits – base case and sensitivity analyses ($m, five-year PV)

Base case	**30.7**
Forecasts adjusted for bias	21.0
Cheaper flexible generation preparation costs	32.8
Slower growth in wind generation capacity	21.7
Higher de-rating factor	15.4
Closer decision point (6 hours ahead)	33.9

The sensitivities range from 110% to 50% of the base case. We discuss these in more detail below.

Figure 8: Sensitivity analyses (five-year PV)



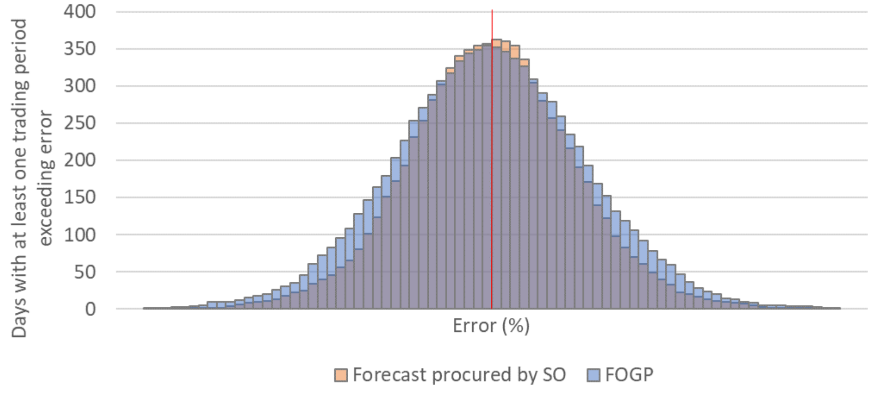
Over a fifteen-year timeframe, the present value of these benefits ranges from $151.5m (higher de-rating factor scenario) to $326.5m (cheaper flexible generation preparation costs scenario).

9.1 Decentralised forecast adjusted for bias

As previously discussed, there is a bias in the FOGP errors towards over-forecasting, whereas the centralised forecast errors have almost no bias. Because the economic cost of over-forecasting (i.e. needing to dispatch expensive demand response to avoid shortages) are more expensive than the cost of under-forecasting (i.e. incurring unnecessary preparation costs), a substantial proportion of the economic benefits of the Authority's proposal come from reducing the bias of errors, rather than the spread of errors.

If over-forecasting bias is sufficiently predictable, the SO could theoretically account for this when preparing forecast schedules (e.g. by reducing the forecast generation quantity in the schedule by the mean error). This would reduce the number of over-forecasting errors that would occur under the status quo. As such, the incremental benefits of a centralised forecast compared to this revised counterfactual scenario could theoretically be substantially reduced.

Figure 9: Error spread with biases accounted for



However, as shown in Figure 9 above, a centralised forecast would still reduce the spread of forecast errors. There would be fewer days with large (in percentage terms) over-forecasting and under-forecasting errors, leading to economic benefits of $21.0 million over five years.

Table 7: Economic benefits sensitivity – decentralised forecast adjusted for bias ($m, five-year PV)

Avoided costs of major over-forecasting events	6.3
Avoided costs of material over-forecasting events	5.0
Avoided costs of major under-forecasting events	1.4
Avoided costs of material under-forecasting events	8.2
Total economic benefits of avoiding forecast error events	**21.0**

9.2 Cheaper flexible generation preparation costs

As discussed above, our base case assumes that preparation costs for a hypothetical 200 MW slow-start generator are $75,000.

However, over time it is likely that slow-start thermal generators will play a smaller role in the balancing of supply and demand. Shortfalls in the future could be managed increasingly by using batteries and other new technology, as the cost of these technologies reduces.

As such, this sensitivity looks at economic benefits if preparation costs for a 200MW unit reduced over time. We assumed that technology advances would result in a preparation cost reduction rate the same as the battery capital cost reduction rate assumed in the MDAG's modelling from 2022.[16]

This would result in an increase in economic benefits relative to the base case, due to the bias of errors under the status quo. The centralised forecast removes this bias, but in doing so it increases the number of times per year that under-forecasting occurs. As such, the centralised forecast incurs more unnecessary preparation costs than the status quo.[17] If we assume preparation costs fall over time, the cost of this bias correction by the centralised forecast will reduce.

Table 8: Economic benefits sensitivity – cheaper flexible generation preparation costs ($m, five-year PV)

Avoided costs of major over-forecasting events	19.8
Avoided costs of material over-forecasting events	14.5
Avoided costs of major under-forecasting events	0.1
Avoided costs of material under-forecasting events	-1.5
Total economic benefits of avoiding forecast error events	**32.8**

[16] Specifically, a reduction rate of 4.0% per annum until 2035, followed by 1.5% until 2050. See slide 116 of [Price Discovery with 100% Renewable Electricity Supply - final simulation assumptions and results (ea.govt.nz)](ea.govt.nz).

[17] These are however, more than offset by the cost savings from a reduction in over-forecasting.

9.3 Slower growth in wind generation capacity

Our base case assumes that wind generation capacity will grow substantially over the next few decades. We have used forecast wind generation figures from the MDAG's modelling from 2022.[18]

It is possible that less wind generation is built than suggested by this modelling. This sensitivity looks at what the net benefits would be if we reduced the forecast demand growth by 25%.

Slower generation growth means that a higher error rate (in percentage terms) is required to trigger a forecast error event (in MW terms). This results in fewer events being triggered every year under both the decentralised and centralised forecasting approaches. However, the shape of the error curve means that with slower wind growth, the Authority's proposal to implement a centralised forecast results in fewer economic benefits than if a larger wind generation growth rate is used.

Table 9: Economic benefits sensitivity – slower growth in wind generation capacity ($m, five-year PV)

Avoided costs of major over-forecasting events	9.4
Avoided costs of material over-forecasting events	12.2
Avoided costs of major under-forecasting events	0.1
Avoided costs of material under-forecasting events	0.0
Total economic benefits of avoiding forecast error events	**21.7**

9.4 Higher de-rating factor

As discussed in section 6.4, the base case assumes a de-rating factor of 50% to account for the following uncertainties:

- the extent to which less accurate forecast schedules impair operational decision making
- the extent to which impaired operational decision making leads to economic impacts.

We have run a sensitivity case where we de-rate the number of forecast error events by 75%. This rather extreme sensitivity reduces the economic benefits (or costs as the case may be) of the base case by half, and as such it is the lowest sensitivity case in our analysis.

Table 10: Economic benefits sensitivity – higher de-rating factor ($m, five-year PV)

Avoided costs of major over-forecasting events	9.7
Avoided costs of material over-forecasting events	6.5
Avoided costs of major under-forecasting events	0.0
Avoided costs of material under-forecasting events	-0.9
Total economic benefits of avoiding forecast error events	**15.4**

9.5 Closer decision point (6 hours ahead)

The base case assumes that flexible resource operators need to make decisions around whether to prepare their resources approximately 12 hours ahead of real time. This reflects the approximate time it takes for a slow-start thermal unit to warm up. However, in the future, flexibility is more likely to be provided by other sources of generation, such as batteries or demand response.

These resources may take less time to prepare, so we have assessed the net benefits under a scenario where generators rely on forecasts only 6 hours ahead of real time. To do this, we adjusted the error probability curve of the forecast procured by the SO (as a proxy for future centralised forecasts) and North Island wind FOGPs (as a proxy for future decentralised forecasts) to match this timeframe.

The results show that economic benefits do not change significantly with a closer decision point. Economic benefits increase slightly as the accuracy

[18] See Figure 5 of [Price discovery in a renewables-based system - final recommendations paper (ea.govt.nz)](). We have converted TWh/yr figures into MW figures using a 39.4% capacity factor (the unweighted average of New Zealand's existing wind farms).

of the centralised forecast improves by more than FOGP accuracy (4.5% vs 2.7%) between 12-hours and 6-hours ahead.[19]

This is consistent with the Authority's previous findings that FOGP accuracy does not improve materially until around 3.5 hours before real time, from which point accuracy steadily improves.[20]

Table 11: Economic benefits sensitivity – closer decision point ($m, five-year PV)

Avoided costs of major over-forecasting events	21.7
Avoided costs of material over-forecasting events	12.9
Avoided costs of major under-forecasting events	0.4
Avoided costs of material under-forecasting events	-1.1
Total economic benefits of avoiding forecast error events	**33.9**

10 Conclusions

Our results show that the benefits of avoiding forecast error events by implementing the Authority's proposal for a centralised wind forecast are substantial. This is likely to be a lower bookend as our assumptions are generally conservative and we have not quantified several other benefits that are likely to occur (as discussed in section 3.3).

We have not quantified proposal implementation costs, as we had insufficient data about the primary cost (i.e. the cost of procuring the forecast). We expect more information to become available as the Authority makes enquiries with forecast providers.

It is also important to note that while implementing a centralised forecast will reduce the prevalence of material and major under and over-forecasting events, it will not remove the issue altogether. Our analysis shows that as the amount of installed wind capacity grows, centralised forecasts will still result in many major and material forecast error events. Improved forecasting, through a centralised forecast, will be beneficial to the system, but will likely need to be complemented by wider suite of measures.

11 Solar generation

Grid-connected utility-scale solar generation is still in its infancy in New Zealand. It makes up only a very small percentage of New Zealand's generation. Currently, Lodestone's 33MW Kohirā solar farm at Kaitaia and its 32MW Rangitaiki solar farm at Edgecumbe are the only two grid-connected solar farms in the country.

We are unable to prove or disprove Proposition 1 in relation to solar (i.e. that a centralised forecast will result in more accurate offers) due to a lack of available data about centralised or decentralised solar forecasts at this time.

Because we cannot establish Proposition 1, we would be unable to estimate the size of economic benefits in *quantitative terms* that would be expected to arise from Proposition 2 (i.e. that more accurate offers will result in economic benefits for New Zealand). However, a qualitative assessment would suggest that in the near term, economic benefits would likely be small. This is because:

- The proportion of solar on the system is relatively small. The maximum forecast error these farms could produce would be 65MW (i.e. if full solar output was forecast but no solar output actually occurs, or vice versa). This is extremely unlikely to occur, and still does not meet any of the MW thresholds for a forecast error event used in our analysis.
- Solar output is correlated with the time of day. In the near term, over-forecasting is more likely to have economic consequences if it occurs when the system is tight. This typically occurs during winter evenings – i.e. when it is dark, and therefore solar output will reliably be zero. When large solar forecasting errors are more likely to occur (i.e. during the middle of summer days), the impact is likely to be lower.

[19] Based on the percentage decrease in the mean absolute error.

[20] See section 3 of [Accuracy of wind and load forecasts (ea.govt.nz)](ea.govt.nz).

However, we consider that this is likely to change in future. Like wind generation, new solar generation is expected to be developed at pace and scale. By 2035, it there is expected to be 1,700 MW of grid-connected solar. At those levels of solar penetration, a much smaller percentage error (17%) could result in a 300MW forecasting error event.

In the future, it is also likely that the times the system will be most stressed will be at times of low wind generation (rather than being tied most closely to demand as is the case now). This means that these solar forecasting errors could occur at very impactful times.

As such, while a centralised solar forecast may not have substantial economic benefits now, it could be useful for the Authority to further investigate centralised solar forecasting, including:

- how the accuracy of decentralised solar forecasting evolves as the installed capacity of utility scale grid-connected solar grows
- the availability, likely cost and accuracy of a centralised solar forecast
- whether a centralised solar forecast could (and should) consider embedded solar generation (and how this would interact with the SO’s forecast of net load).