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**To:** Electricity Authority
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# Review of forecasting provisions for intermittent generators in the spot market – Issues and options paper

Genesis Energy Limited **(Genesis)** welcomes the opportunity to comment on the Electricity Authority's **(the Authority)** issues and options paper on forecasting provisions for intermittent generators in the spot market.

Genesis is supportive of the aims of this consultation and agrees it is necessary to improve the accuracy of intermittent generation forecasting. To the extent that improved forecasting can enable better decision-making by participants, that is a good thing.

## Complexity of unit commitment decision-making will increase with the growth of intermittent renewable generation

We broadly agree with the problem definition in the paper and applaud the Authority for its thorough analysis and quantification of costs attributable to inaccurate intermittent generation forecasting. However, it is worth emphasising that, while the options in this paper will potentially help improve decision-making in the market, they will not be sufficient to mitigate the unit commitment problem. This is partly due to limitations (noted in the paper) to the accuracy of wind and solar forecasting, which makes it difficult to accurately forecast intermittent generation out over a time horizon (i.e. beyond 6 hours) often required for thermal unit commitment decisions, particularly for the slower-start Rankine units at Huntly. Time horizon for thermal unit commitment decisions can vary widely, and in some cases extends well beyond the 8-10 hours in the paper based on factors such as fuel availability, staff availability, and plant readiness. Nonetheless, implementing standards to maximise forecasting accuracy over an extended timeframe will be beneficial and improve decision-making.

As noted by the Authority in this paper and by Genesis in recent submissions, the uncertainty and riskiness of thermal unit commitment has increased in recent winters and is only likely to increase further as intermittent generation achieves a higher penetration within the electricity system. To the extent inaccurate forecasting of intermittent generation exacerbates this uncertainty and riskiness, it has potential to undermine system reliability. Given it is our position that pursuing a 100% renewable electricity system is unlikely to be the fastest or most economic route to decarbonising the economy more broadly, the Authority's efforts to improve forecasting accuracy are timely, and these requirements should be future-proofed to ensure thermal unit commitment can be done accurately and efficiently. As we have noted in previous submissions, we consider that there is a risk that the thermal plant currently relied upon to manage through energy and capacity shortages becomes uneconomic to maintain and is retired before the market ceases to require it (however infrequently).

## Incentives will be critical to improving intermittent generation forecasting

To the extent all the options canvassed will improve forecasting accuracy, we are supportive of these options in principle. Regardless of which option is progressed, incentives (and penalties) will be critical to ensuring any new arrangement improves system-wide forecasting accuracy. Within the Authority's timeframe of implementing a new arrangement by winter 2024, a decentralised option with incentives and penalties (Option 1) may be the most effective and efficient arrangement for incentivising accuracy and for allocating the costs resulting from inaccuracy among participants.

Longer-term, we also think Option 4 (compulsory ahead market) should be investigated further by the Authority but agree this option cannot be implemented before winter 2024. The appeal of some form of ahead market, covering all forms of generation (not just intermittent) as well as demand, is that it will likely be the most efficient and fair way to incentivise accuracy and allocate costs resulting from inaccuracy among participants, with penalties proportionate to the materiality of the impact any errors have on spot prices (and likewise incentives). It may prove a more effective and durable arrangement over the longer-term, in part because forecasting accurately may grow more difficult in the future, not just from growth in intermittent generation but also due to growth in demand response behind-the-meter. Factors such as these could make the job of a central forecaster more difficult.

In contrast, while we note the potential benefits of a centralised arrangement, one of the key limitations is that it will be difficult to include incentives and penalties in a contract with a service provider that are proportionate to the potential market impact of accurate and inaccurate forecasting, as we think it unlikely any forecaster will be willing to take on liability for the impact of errors.

Nonetheless, we agree with the Authority that it will be important to strike an appropriate balance between improving forecasting accuracy while enhancing competition by ensuring forecasting requirements, incentives and penalties are not unnecessarily burdensome and provide a level playing field.

We broadly agree with the Authority's evaluation criteria, albeit noting there may be trade-offs between some criteria. For example, the most durable and future-proofed arrangement may not be the most quick and straightforward to implement (as noted above).

## Conclusion

We congratulate the Authority on a thorough analysis of the costs and risks from inaccurate forecasting of intermittent generation, and for seeking industry feedback on a range of potential options for addressing this problem. Genesis supports implementing changes to improve intermittent generation forecasting to the benefit of the electricity system.

Yours sincerely,

Mitch Trezona-Lecomte
**Senior Advisor, Government Relations and Regulatory Affairs**

## Genesis's response to the Authority's consultation questions

| Question | Genesis Response |
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| Q1: Do you agree with the Authority's problem definition? If not, why not? | Yes. In particular, we agree with the Authority that the unit commitment problem will become more acute and impactful as both peak demand and the supply of intermittent generation grows.<br><br>However, as noted in previous submissions (see the CEO Forum's submission on the Authority's Driving Efficient Solutions in Winter 2023 paper), the unit commitment problem is caused by a wider range of factors in addition to inaccurate forecasting of intermittent generation (albeit inaccurate forecasting is one significant factor), and the options assessed in this paper, while helpful, will not be sufficient to resolve this problem.<br><br>We applaud the Authority's quantification of costs attributable to inaccurate intermittent forecasting. One additional comment we would make is to reiterate a point made in our recent submission to MDAG on its Price Discovery under 100% Renewable Electricity Supply options paper: the value consumers place on security of supply remains to an extent unknown in the current market, and we consider there is a high risk that it is currently undervalued. It is unclear from the consultation paper or the EY analysis (appendix B) whether and how VoLL has been factored into the analysis: while VoLL is listed as an Impact on page 8 of EY's analysis, the discussion on pages 29-30 notes that price increase resulting from over-forecasting of wind are likely attributable to dispatch of fast-start, higher cost generation i.e. an efficiency cost rather than VoLL. From the discussion on pages 31-32, we assume VoLL has not been included in the quantified costs. It would also be useful to understand these costs relative to total market liquidity i.e. as a percentage of market activity.<br><br>To the extent that inaccurate forecasting of intermittent generation contributes to or increases the risk to system reliability, and that the value of this reliability / cost of lost reliability remain for the present difficult to quantify, the costs quantified in the Authority's analysis do not fully capture the potential costs of the problem.<br><br>Another way of looking at this point is brought out by the likelihood the quantifiable system costs of inaccurate forecasting (as quantified in the paper) will decrease as thermal generation is displaced by intermittent generation (assuming the frequency and MW capacity of thermal under/over generation decreases accordingly). However, even as the quantifiable costs attributable to inaccurate forecasting decrease, the reliability problem will arguably grow more acute as the riskiness and complexity of thermal unit commitment grows.<br><br>We would also note that one effect of inaccurate wind forecasting noted by EY in Appendix B is the potential decrease to thermal generation capacity. Appendix B describes the desirability of a *'coordinated and timely phase out of the thermal generation fleet, regardless of slow or fast start, will be required to ensure overall system stability and security of supply.'* While this point is not reiterated in the Issues and Options paper itself, we would refute the |

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| | claim that system stability and security of supply are improved by thermal phase out. This claim also appears to be inconsistent with the Authority's consultation 'Ensuring an Orderly Thermal Transition', which shows demand for thermal generation will likely remain significant in the short-term, with a small level of thermal generation likely remaining in the system at least until 2032. It is our position that the opposite is more likely true, and that pursuing a 100% renewable electricity system is unlikely to be the fastest or most economic route to decarbonising the economy more broadly. This is consistent with the preferred scenario in the recent BCG report 'The Future is Electric' as well as the Climate Change Commission's demonstration pathway in its advice to the Government on the first three emissions budget periods and emissions reduction plan ('Ināia tonu nei: a low emissions future for Aotearoa') and its more recent draft advice on the second emissions reduction plan.<br><br>As noted in our previous submissions, our position is that retention of some form of thermal generation plant will be the most economic mechanism for maintaining system security and reliability.<br><br>In the same paragraph, Appendix B also refers to the risk that consistent inaccurate forecasting of intermittent generation reduces the asset life of thermal generation plant. We would here note that the key risk is that inaccurate forecasting of intermittent generation contributes to a shortening of the *economic life* of thermal generation assets by increasing the uncertainty and therefore riskiness of thermal unit commitment to the point where it is no longer viable to participate on the spot market.<br><br>One additional aspect to the problem addressed by the Authority's paper worth noting is that of 'blackout ranges' for wind, which occur when the level of wind resource at a given time exceeds the generation capacity of wind generators. This can significantly and suddenly reduce wind generation in real time, even when the available wind resource is high. As noted by the Authority and Concept Consulting in Appendix A, ensuring forecasting arrangements capture such 'idiosyncratic factors' will be important to improving accuracy. |
| Q2: Do you agree that a new forecasting arrangement should apply to all grid-connected intermittent generators that are required to submit offers? | Our view is any new forecasting arrangement should include anyone who is required to submit offers, and this should mean anyone with installed capacity >10MW, whether grid connected or not. |
| Q3: [For thermal generators] 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. | Unit commitment decisions are made ex-ante based on information available at the time, based on numerous factors, and therefore we do not think it meaningful or useful to try and provide an ex-post assessment of unit commitment decision-making.<br><br>Moreover, the assessment of whether a decision was 'correct' (i.e. rational) depends to an extent on whether you take the perspective of an individual generator or the system (NZ Inc.). 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 (foregone potential revenue from participating in the spot market which, as a |

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| | counter-factual, is difficult to quantify) whereas the cost to the system / NZ Inc. will be an economic cost reflected in higher prices paid by consumers and, in the worst cases, a power outage (as occurred on 9 August 2021).<br><br>What is effectively quantified in the Authority's analysis (supported by EY) is that uncertainty exacerbated by inaccurate intermittent generation forecasting exacerbates risk for thermal generators and other market participants, increasing costs to both market participants and NZ / the system more widely (i.e private and public costs). Recent analysis by BCG and Concept Consulting, including the Authority's Orderly Thermal Transition paper, demonstrates the margin for error of thermal unit commitment is likely to continue narrowing as lower-cost intermittent generation progressively displaces thermal generation. This will increase the riskiness of thermal unit commitment going forward. |
| Q4: What else, if anything, should be considered when assessing the relative advantages and disadvantages of the four forecasting arrangements the Authority has identified? | As noted by the Authority, there is a degree of interdependency among the design considerations raised in the paper. For example, the type of accuracy standards, incentives and penalties that are most effective and appropriate will differ for a centralised vs decentralised arrangement. Therefore, we encourage the Authority to consider interdependencies among components of different options. |
| Q5: What other types of forecasting arrangements, if any, should be considered to improve the issue of inaccurate and unreliable forecasts? | |
| Q6: Do you agree with the proposed evaluation criteria? If not, what is your view and why? Are there other criteria the Authority should consider? | |
| Q7: Do you agree with the Authority's assessment of each forecasting arrangement above? If not, why not? | While we see the potential benefits of a centralised arrangement, we would note the following reservations:<br>- 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.<br>- Under Option 3, it is unclear why a generator would choose to self-forecast, if this would also mean incurring liability for any errors. It is likely Option 3 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 |

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| | system-wide forecast with liability for any material errors. Some incentives will likely also be needed for generators to submit their own forecasts.<br><br>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).<br><br>We also note 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. We therefore suggest the Authority explore this further longer-term (noting it will not be possible to implement before winter 2024). |
| Q8: The Authority has not weighted the criteria based on importance. Are there particular criteria you consider more important than others? | We consider the criteria 'Reliability, Mitigates risks to security of supply' should be weighted very highly, as the consequence of getting this wrong (i.e. load management) is high to the industry, customers and economy as a whole.<br><br>We agree with the desirability of Enhancing Competition and ensuring forecasting requirements do not act as an unreasonable barrier to entry.<br><br>Successfulness in other jurisdictions may be less important than other factors given differences in NZ's electricity system, such as the high proportion of hydro and our lack of connectivity to other systems.<br><br>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 Future-Proofed i.e. an arrangement that can be implemented before winter 2024 may not be the best long-term arrangement. As noted above, a day-ahead market may prove beneficial longer-term, notwithstanding the fact it cannot be implemented by winter 2024. |
| Q9: Are there additional criteria the Authority should be considering? | One factor that may require further consideration to ensure any new arrangement remains durable and future-proofed is how other renewable sources of electricity, particularly solar or off-shore wind, will operate under any new requirements. |
| Q10: How frequently should intermittent generation forecasts be updated, and how often | In principle, the timing and frequency of intermittent generation forecasts required under the Code should be designed to maximise the availability of reliable information as an input to the market. |

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| should IGs be required to revise their offers to reflect updated forecasts? | Any automated generation forecasting system will be able to submit a new forecast whenever a new weather forecast becomes available, which in our experience depends on providers, but is at most every 6 hours and easily every hour (presumably a centralised solution would have at least this frequency). There are also long schedules that are published every two hours (or every even hour). Our suggestion would therefore be for a requirement to submit a forecast for the next 36 hours every two hours - a new wind forecast should be available prior to the release of the long schedule forecast which occurs every even hour, meaning the forecast needs to be in c. 5 mins before then.<br><br>Additionally, automated persistence forecasting could be allowed, especially for a self-forecasting solution, but only for the next 1-2 trading periods. Generation can fluctuate significantly minute-by-minute, and the methodology should be given further consideration. As an example, this could include a single snapshot of generation sometime during the last period vs an average over some length of time. Such an arrangement would ensure the front end of the curve is reasonably accurate vs. using an old forecast. |
| Q11: Do you think the Authority should implement accuracy standards? If not, please explain why. | Yes. In principle, we agree it will be important to design accuracy standards that balance in particular Effectiveness, Efficiency and Reliability and Enhancing Competition.<br><br>The specifics of the accuracy standards will depend on which forecasting arrangement is chosen (see our response to Question 12 below). For example, process standards will be more appropriate for a centralised provider contracted by the Authority or System Operator, whereas outcome standards will be more desirable and appropriate under a decentralised arrangement, provided there are also incentives/penalties to go with it.<br><br>Standards should aim to address both under-forecasting and over-forecasting. To help improve thermal commitment, they should also be aimed at getting forecasts as accurate as possible for an extended period, while bearing in mind that forecasts that far out are inherently inaccurate as weather is hard to predict. Maximising accuracy for a 12 hours-ahead time horizon would be beneficial, albeit noting our caveats around the variability of thermal unit commitment decision timeframes (which are sometimes longer than 12 hours). |
| Q12: If the Authority implemented accuracy standards:<br>- a) do you think outcome or process standards would be more effective?<br>- b) should there be single standard or multiple standards across different timeframes?<br>- c) should the standard(s) be focused on ensuring actual generation is within 30 | a) The goal of the whole process should be to get the best forecasting outcome, so outcome standards should be preferred. Option 1&4 (decentralised), with penalties/incentives, naturally lead towards that outcome. In a centralised market, process standards would likely be easier to implement; outcome standards may be difficult to enforce given any penalties for failure to meet these are unlikely to be proportionate to the impact, and it is difficult to envisage a service provider taking on liability for errors.<br>b) Multiple standards. As noted, the time horizon for decision-making on whether to commit Huntly units varies depending on a range of factors, including fuel availability, staff availability, and plant readiness. The goal of accuracy standards should be to maximise accuracy over as long a time horizon as is |

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| MW of the amount forecast, or should the MW threshold be higher or lower? Should the accuracy standards be based on the percentage of installed capacity rather than a certain amount of MW? | reasonably possible, subject to constraints to the ability to forecast weather accurately. It will therefore likely be appropriate to have multiple and differing standards across different time horizons.<br>c) In addition to implementing accuracy standards, we agree the Authority should review and rationalise the existing 30 MW threshold to ensure accuracy standards are applied fairly. We favour a percentage of installed capacity threshold, as this would be fairer and create a level playing field across all generators, regardless of their total capacity. Given the expected growth in intermittent generation, the percentage threshold would also better achieve the Authority's desired outcome of improving system-wide forecasting accuracy. Alongside a percentage threshold, we think a minimum MW materiality threshold could also be included to prevent immaterial errors being penalised unnecessarily. |
| Q13: Following the 9 August 2021 grid emergency, reports from two investigations recommended the Authority amend the Code to disallow persistence forecasting and require wind generators to make more accurate offers to the system operator about supply.<br><br>Do you agree the Authority should amend the Code to disallow persistence forecasting? | We do not agree that persistence forecasting should be disallowed completely. However, in our experience persistence forecasting is only accurate over a very short period of between 30 to 60 minutes, and therefore it should not be used over a time horizon of more than 60 minutes.<br><br>Some thought should also be given to the methodology used in persistence forecasting, e.g. a single snapshot of generation sometime during the last period, vs an average over some length of time, as generation sometimes fluctuates significantly minute by minute and a snapshot might not be representative.<br><br>The timing of the submission of the 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. |
| Q14: Do you think the Authority should implement incentives and/or penalties for non-compliance? If not, please explain why. | Yes. See our response to questions 15 and 16. |
| Q15: If the Authority was to implement a decentralised forecasting arrangement, do you have any suggestions for what type of incentives could be applied? | 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. Such an arrangement would be most effective where charges/fines are proportionate to the materiality of the impact of the inaccuracy e.g. 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.<br><br>As noted above, 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. |

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| Q16: If the Authority was to implement a centralised forecasting arrangement:<br>a. Do you have suggestions for what type of incentives could be applied?<br>b. Should penalties for not meeting the standard(s) be prescribed?<br>c. Should penalties be higher for over-generating than under-generating (or vice versa)? | a) Financial incentives could be built into the contract with the forecast provider based on the overall accuracy of the forecast they produce.<br>b) Yes. Again, these could be included in the contract with the forecast provider and should apply to all periods, and not just over those in which over-generating and under-generating has a marked impact on spot prices.<br>c) No, they should be the same. 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.<br><br>As noted, 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 (see our response above to Question 15). 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. We suggest the Authority consider this issue carefully in the next phase of its design work. |
| Q17: Do you have view on who should have responsibility for submitting forecasts and who should pay for forecasting? | In the case of a centralised forecasting arrangement, and in the absence of a self-forecasting option, our suggestion would be for Transpower or the Authority (whichever is preferable) to submit the forecast, with the cost covered by intermittent generators based on their share of installed intermittent generation capacity (or rather, expected yearly volume) with an associated forecast.<br><br>In the case of 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, our suggestion would be for the operator of the intermittent generation 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. |
| Q18: Do you have a view on what types of information should be published and what platform it should be published on? | We recommend WITS forecast and the associated dispatch schedules.<br><br>If going for a centralised forecast, it would be useful to have an idea of distribution/uncertainty, e.g. a P25/75 or P10/P90 forecast for the whole horizon in addition to the submitted P50/expected (and aggregated to the relevant level e.g. Island). Providers such as Meteologica or Metservice via their EPD forecast can already provide that. For Option 3, this would likely require generators submitting their own forecast to also provide those uncertainty measures. |