Collaboration on Energy and Environmental Markets

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Submission to the Semi scheduled generator rule change(s) Issues paper

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24 July 2020

Mr Peter Adams

General Manager, Market Performance

Australian Energy Regulator

Lodged electronically

Dear Mr Adams,

Re: Semi-scheduled generator rule change(s) Issues paper

The Collaboration on Energy and Environmental Markets (CEEM) welcomes the opportunity to make a submission to the Australian Energy Regulator (AER) regarding its Issues paper on potential rule changes to ensure that semi-scheduled generators comply with dispatch instructions in the National Electricity Market (NEM).

About us

The UNSW Collaboration on Energy and Environmental Markets (CEEM) undertakes interdisciplinary research in the design, analysis and performance monitoring of energy and environmental markets and their associated policy frameworks. CEEM brings together UNSW researchers from a range of faculties, working alongside a number of Australian and international partners. CEEM's research focuses on the challenges and opportunities of clean energy transition within market-oriented electricity industries. Effective and efficient renewable energy integration is key to achieving such energy transition and CEEM researchers have been exploring the opportunities and challenges of market design and policy frameworks for renewable generation for several decades. More details of this work can be found at the Collaboration website. We welcome comments, suggestions, questions and corrections on this submission, and all our work in this area. Please feel free to contact Abhijith (Abi) Prakash (abi.prakash@unsw.edu.au) regarding this submission, or Associate Professor Iain MacGill, Joint Director of the Collaboration (i.macgill@unsw.edu.au) for other CEEM matters.

Our approach

We have taken an alternative approach to the structure of this submission. We are in broad agreement with the principle and intention of the proposed rule change(s) but have concerns around their implementation. Our submission is, therefore, divided into three main sections. Section 1 provides a brief summary of our responses to the formal questions posed in the Issues paper. Section 2 provides context around the importance and benefits of central dispatch, the consequences of current dispatch arrangements for scheduled and semi-scheduled generators, and the characteristics and capabilities of variable renewable energy (VRE). Section 3 summarises our analysis and concerns with the implementation of the two rule change options favoured by the AER.

Executive summary

In principle, we are in favour of VRE generation being considered as dispatchable resources. The rule change(s) being considered are an important step in ensuring the market design of the NEM can accommodate a higher penetration of VRE while meeting technical and economic requirements. However, we have four main concerns with the implementation of the AER's favoured options:

1. While our analyses suggest that the potential costs of mitigating VRE variability through curtailment to comply with the favoured options will be manageable, we expect that these costs will be material to market participants and the viability of VRE projects over the long term.
2. Our analyses of potential costs also assumes that any over-generation is curtailed - a cost that is not borne by scheduled generation that are deemed to be in conformance with dispatch

targets. We recommend that AEMO and the AER should clearly outline what dispatch conformance consists of and consider a definition that is technology-agnostic and therefore fair.

3. Market participants that operate semi-scheduled generators may be subject to avoidable costs due to present AWEFS/ASEFS forecast (and potentially self-forecast) uncertainty. Our analysis suggests that lagging persistence forecasting is being used to determine dispatch levels for a large proportion of the semi-scheduled generating fleet. While we acknowledge the work underway to enable participant forecasts to be used instead of AEMO forecasts, we recommend that the AER and AEMO investigate the potential limitations of AWEFS/ASEFS before proceeding to propose a rule change. Additionally, AEMO should publicly publish more detailed assessments of AWEFS/ASEFS methods and outcomes to assist all stakeholders in contributing to potential improvements in their performance. Such improvements would reduce the costs borne by participants and improve the accuracy and efficiency of the central dispatch process.
4. While the adoption of an active power (MW) target with a specified target (Option 1) would avoid legacy and transition issues associated with removing the semi-scheduled category altogether (Option 2), it does not address the existing disconnect and inconsistency in the application of Causer Pays. We recommend that the AER further consider the interaction of current and potential Causer Pays mechanisms with any proposed rule change arising from this process.

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1 Summary responses to the Issues paper questions

1.1 Is a rule change required to address the issues described in the paper?

As we discuss further in Section 2, we agree with the AER on the growing challenges of semi-scheduled generation disregarding dispatch *levels*. In some of these instances, the power system is seeing major changes in active power output from semi-scheduled generation in response to factors such as negative pricing. These major changes in active power output are problematic as they have not been formally dispatched by AEMO via rebidding. For more detail, please see our discussion in Section 2.

It would have been beneficial to stakeholders if the Issues paper had provided some more detail on the nature of these 'intentional' deviations given the highly variable and somewhat unpredictable underlying solar and wind resources that semi-scheduled plants utilise. The AER could have included further analysis or discussion around:

- The proportion of dispatch intervals impacted by these deviations.
- The correlation in deviation across semi-scheduled generators. The implicit assumption in the Issues paper is that deviations are highly correlated (i.e. in the same direction from multiple plants) in response to factors such as negative prices. It is unclear from the evidence presented in the Issues paper that this is the case.
- The potential reasons for semi-scheduled generators changing output without, or prior to, a rebid. It is unclear to us if this is a consequence of inaccurate pre-dispatch price forecasts, and if not, why semi-scheduled generators bids do not reflect their preferences during negatively-priced dispatch intervals.

More detailed analysis would give all stakeholders greater clarity on the extent of the problem of 'deliberate', significant and correlated deviations from VRE plants. It would also be useful to provide some context around other similar dispatch challenges (e.g. price responsive demand, which currently does not formally participate in central dispatch).

We also note that analysis in the Issues paper (Figure 4 and Figure 5) is based on deviation from levels determined by AEMO forecasts. In Section 3, we flag some limitations in the current AEMO wind and solar forecasts that may be exacerbating deviations.

1.2 Are there other impacts on the market that are not presented in the paper?

Given the linkages across energy, frequency control and derivative markets and evolving participant behaviours within the NEM, it is likely that there will be other unexpected market impacts if any of the rule change options were to be proposed and implemented. The risks associated with such surprises need to be weighed against the importance of addressing a growing system security challenge.

In general, we would argue that VRE generation should contribute towards determining and then see energy market signals that drive efficient operational, and eventually investment, outcomes. In Section 3, we examine the potential curtailment costs for 'firm' VRE generation dispatch. Such curtailment has costs to the plant itself, but also to the market as a whole given the very low operating costs of VRE and the missed opportunity to offset fossil-fuel plant that have both fuel costs and significant environmental externality costs. Existing Causer Pays arrangements also raise concerns for us, as also discussed in Section 3.

1.3 Are there other impacts not considered from the difference in the requirements for scheduled and semi scheduled generators to follow dispatch instructions?

We discuss the consequences of current dispatch arrangements within Section 2. In considering the two favoured rule change options, we recommend that AEMO and the AER outline how dispatch conformance will be measured for VRE and how this process might be similar or different to dispatch conformance monitoring for conventional scheduled plants (refer to Section 3 for more detail).

1.4 Has the semi scheduled category done its job?

In principle, multiple participant categories and technology-specific requirements and rules adversely impact market efficiency. It is also notable that several wind farms did participate as scheduled generators in South Australia prior to the introduction of the semi-scheduled classification. However, in practice, the differences between conventional scheduled plants and VRE seem sufficiently large such that separate categories are appropriate.

Keeping the two categories also provides some flexibility for dealing with other market issues that may arise as VRE penetrations grow. The growth in hybrid renewables plants incorporating storage is a particularly interesting issue in this regard. Ideally, these plants would not be classified under yet another category as they seem to have the capabilities required of the scheduled and semi-scheduled classifications.

1.5 Are the four options presented in the paper the most efficient way to achieve the desired outcomes?

We are not confident, nor should the AER be, that any of these options is assuredly the 'most' efficient way to achieve the desired outcomes. As always, each rule change has potential interactions – for good and bad – with other rule change processes underway. For further discussion around the impacts of the two favoured actions and for our recommendations, refer to Sections 2 and 3.

1.6 Are there other options?

Whilst there are many possible options, the two preferred approaches in the Issues paper both seem reasonable responses to the challenge being faced.

1.7 Are there any differences in how the four options would apply to wind or solar?

This is a good question but not one we feel able to address at this time. However, an ideal solution would avoid creating further generation classifications.

1.8 Do stakeholders have views on the potential costs and benefits of each of the options presented in this paper?

Please see our discussion on costs in Section 3.

1.9 What are the potential impacts of each of the options presented in this paper on participants that are likely to be affected?

We discuss some of the potential impacts in Section 3 and look forward to the responses from a diverse group of stakeholders on this question and on the consultation process as a whole.

1.10 How can the flow of data and information to AEMO be improved?

While there are certainly opportunities to improve the flow of data and information to AEMO, we would argue that AEMO (and the AER) should also be looking to provide improved data flow and information to stakeholders on issues including the extent of the problem this rule change is seeking to address (see our response to question 1 above) and the performance of AWEFS/ASEFS (as detailed in Section 3).

1.11 Only two options appear to satisfy the Energy Council's intention for semi scheduled generators to follow dispatch instructions. Should further consideration be given to the options that were noted as not practicable (sharper causer pays factors and amendments to registration of semi scheduled generators)?

As we discuss in both Sections 2 and 3, and as most stakeholders are well aware, current Causer Pays arrangements are not providing sharp incentives for improved frequency control outcomes. Even improved Causer Pays arrangements are unlikely to make this a preferred option. We also agree with the AER's conclusion in the Issues paper that amending registration conditions will likely be ineffective.

2 Context and key issues

2.1 The role of dispatch compliance in secure NEM operation

In the NEM, security-constrained economic dispatch, carried out by the National Electricity Market Dispatch Engine [1], produces a least-cost dispatch solution, subject to the revealed preferences of participants and system security constraints [2]. As such, if a generating unit deviates from its dispatch target, it is generally moving the system away from an economically efficient and secure state.

The impact of deviations from a particular generator's dispatch target depends largely on the behaviour of demand and other generators at that time. A deviation above target from a plant might be counteracted by an unexpected demand increase, or a decrease in the output of other generators below their own targets. In such cases, deviations may assist in maintaining system security and reduce system operating costs. When deviation from dispatch is in opposition to excursions away from the nominal frequency of 50 Hz, supply-demand mismatches can lead to an increased need for and utilisation of frequency control ancillary services (FCAS). The design and procurement of FCAS in the NEM still reflects an assumption of dispatch target conformance. Regulation FCAS is procured to respond to minor deviations in frequency caused by deviations from dispatch targets and changes in load over the timescale of minute [3]. Contingency FCAS is procured to respond to an unexpected loss of load or generation that would otherwise comply with dispatch instructions (barring network failure) [4].

As a general principle, our chosen market arrangements rely on units operating in a predictable way and conformance with central dispatch is key to this. Correlated deviations across a number of plants (e.g. in response to negative prices) are particularly problematic and will result in higher system operating costs. Over the longer term, dispatch non-conformance contributes to greater uncertainty in the operation and security of the power system. The larger reserve volumes and planning margins required due to greater uncertainty increases the need for interventions by AEMO [5], leading to higher system costs and lower market cost-efficiency.

2.2 Conformance under current dispatch arrangements

2.2.1 Scheduled generators

A scheduled generating unit is determined to be non-conforming if it fails to respond to dispatch instructions within what AEMO considers to be a tolerable time and/or accuracy (NER Clause 3.8.23). The dispatch instructions consist of some form of linear ramp from a unit's initial active power output to a target active power output at the end of the dispatch interval (through Automatic Generation Control or otherwise) [1]. The AER is responsible for investigating potential breaches [6] and has previously initiated proceedings against Snowy Hydro (2015), Energy Australia and AGL (2017).

2.2.2 Semi-scheduled generators

Dispatch *levels*, rather than targets, apply to semi-scheduled generation (we note that the Issues paper sometimes incorrectly refers to 'targets' for semi-scheduled generation). These are determined through forecasting systems and have historically been determined by AEMO's Australian Wind Energy Forecasting System (AWEFS) and Australian Solar Energy Forecasting System (ASEFS). Since 2018, a self-forecasting trial has enabled participants to submit their own 5-minute-ahead Unconstrained Intermittent Generation Forecast (UIGF). These are assessed by AEMO and used in dispatch if they are determined to be reliable and no worse in accuracy than AWEFS/ASEFS [7].

A semi-scheduled generating unit is determined to be non-conforming if its actual generation exceeds its dispatch level within a semi-dispatch interval (NER Clause 3.8.23). The dispatch level can be interpreted as a cap, as non-conformance is defined by exceedance of rather than deviation from dispatch level. A semi-dispatch interval flag is only active when [1]:

- there is a binding network or FCAS constraint
- market factors require unit active power to be constrained (e.g. marginal generation) or generating unit constraints (e.g. ramp rates)

This definition of non-conformance allows semi-scheduled plant to remain in compliance with the Rules outside of semi-dispatch intervals when they either unintentionally or intentionally deviate from their dispatch levels, so long as their bids accurately represent the unit's capability (NER Clause 4.9.8(e)). During semi-dispatch intervals, they can remain in compliance as long as any deviation is below their dispatch level. Unintentional deviation could result from the variability of the unit's primary energy resource, or uncertainty in forecasting or unit performance. Intentional deviation includes response to negative pricing, which is one of focus points of the Issues paper.

2.3 Consequences of current arrangements

Based on the examples outlined in the Issues paper, we see two negative consequences of current dispatch arrangements:

1) Price-motivated dispatch level non-compliance
    a) VRE generation is reducing active power output in response to negative pricing.
        i) This distorts the outcome of security-constrained economic dispatch.
        ii) The ability for VRE generation to respond in this way is inconsistent with rules for scheduled generating units which bear the exposure to negative pricing if dispatched.
2) Non-compliance with linear ramp leads to fast ramping akin to step change in active power
    a) Rapid injection or withdrawal of active power across several plant is undesirable as:
        i) It may lead to system instability.
        ii) A slower dynamic response (e.g. primary frequency response from thermal plants) may be the only available sustained response. In this situation, the power system may experience larger instantaneous supply/demand imbalances and therefore larger frequency excursions.
    b) Step changes are incongruous with the expectation that scheduled generators and loads will move between their targets in a linear fashion. We note that step changes are not unique to semi-scheduled generation - price-responsive demand can behave in a similar manner without formally participating in central dispatch.

Combined, these factors can lead to the increased utilisation of available normal operating frequency band primary frequency response, regulation FCAS and even contingency FCAS, should these issues become more frequent and serious as:

a) negative prices become more common.
b) the dispatched capacity and active power of semi-scheduled plant increases into the future.
c) hybrid renewable-storage plants become more commonplace. These plants may deviate more from forecast output than conventional VRE given the wider range of operation possible with energy in storage.

d) demand become more price-responsive. We encourage AEMO and the AER to include discussion around the similarities and differences between semi-scheduled generation and such demand, and their current and proposed management in dispatch.

2.4 Characteristics and capabilities of variable renewable energy

While definitions can vary, we use the term variability to refer to expected (forecast) fluctuations in the supply demand-balance, whereas uncertainty refers to unexpected fluctuations in the supply-demand balance [8]. Variability and uncertainty in active power supply and demand are inherent to any power system but increase with higher penetration of variable renewable energy (VRE). Fluctuation in loads [8] and oscillatory active power output from synchronous generators [9] contribute to variability, while the potential for unexpected outages of generators or loads can contribute to uncertainty [5]. In the context of VRE, variability at the dispatch timeframe is associated with changing weather conditions (e.g. wind speed, cloud cover) whereas uncertainty is associated with weather and/or generation forecast limitations and error. Uncertainty also includes intentional deviations by semi-scheduled generators.

Control systems in modern power electronic convertors and appropriate market arrangements can reduce the contribution of VRE to variability and uncertainty. Given primary energy availability, power electronic convertors can exercise rapid and precise control of a VRE generator's active power output within the constraint of its primary energy availability [10]. The ability to rapidly 'start-up' and ramp VRE generators means they provide more flexibility than thermal plants around start-up time, ramp rates and minimum operating levels [11]. The precision and speed of VRE generation active power control is observed in the negative price response and high ramp output changes shown in the Issues paper, operation of the Hornsdale Power Reserve [12] and in VRE FCAS trials [13], [14]. However, as was the case in the latter examples, some level of VRE curtailment may be required to provide ‘headroom’ for output raises and hence reliable or 'firm' active power control [15]. Any implementation of market-based mechanisms or regulatory changes (such as the proposed rule) that require firm VRE dispatch must consider and/or address the opportunity-cost of the required curtailment of VRE generation. We examine case studies and assess the potential opportunity costs associated with curtailment for the AER’s favoured options in the next section of this document (see Section *3.1 Potential VRE curtailment costs*).

Improving forecast accuracy can reduce the uncertainty of VRE generation and dispatch as a whole, but where this proves challenging, forecast limitations and uncertainty should be accounted for. If forecast uncertainty is not considered, or a forecast has significant error, the benefits of the favoured rule change proposals may not be realised. AEMO has begun to address forecast uncertainty by incorporating the Forecast Uncertainty Measure into its reserve level determination process [5], but we would argue that such measures should be incorporated into dispatch processes or the forecasts themselves (e.g. the use of P90 active power forecast) if firm VRE dispatch is required. As they stand, the favoured options outlined in the Issues paper implicitly assume that any forecast uncertainty is accounted for within the forecasted dispatch level. We outline our concerns surrounding the implementation of VRE forecasts into the current dispatch process in the next section of this submission (see Section *3.2 VRE generation forecasting accuracy*).

3 Assessing the proposed rule change options

We agree with the AER's assessment that the following two options (outlined in Appendix D) are the most preferable of the four put forward:

1. Amend the definition of a dispatch instruction to semi scheduled to be a target in the form of a MW for the end of the dispatch interval and ramp rate (Option 1).
2. Delete the classification of semi scheduled generation and subject to legacy or transitional arrangements require all current semi scheduled generation to be classified as scheduled (Option 2).

In light of these options, we believe the following should be considered prior to submitting a rule change proposal:

1. Potential costs that VRE generators may incur due to curtailment to provide firm active power control.
2. Impact of current VRE generation forecasting practices and accuracy.
3. The interaction of the options with Causer Pays.

3.1 Potential VRE curtailment costs

For both of the favoured options in the Issues paper, there would be potential costs associated with active power curtailment by semi-scheduled plants to ensure compliance with dispatch targets and trajectories. Our analysis of curtailment levels suggests that these costs would likely be smaller than those incurred due to curtailment for other reasons (e.g. network constraints). However, over the longer term, these costs may be material to participants and project viability. The minimisation of these costs will require accurate forecasts, as discussed in Section *3.2 VRE generation forecasting accuracy*. The analysis in this section also assumes that any over-generation is curtailed - a cost that is not borne by scheduled generation that are deemed to be in conformance with dispatch targets. We recommend that AEMO and the AER should clearly outline what dispatch conformance consists of and consider a definition that is technology-agnostic and therefore fair.

3.1.1 Curtailment required to mitigate solar PV variability for firm dispatch (Option 2)

Our analysis of partial curtailment to firm solar PV dispatch shows that curtailment required to account for all variability and ensure strict compliance with dispatch levels within a 5 minute dispatch period would be relatively minor on average (see detailed analysis by the authors in [15]). The degree of curtailment varies with weather conditions, ranging on average from approximately 7% to 11% of rated capacity during high variability periods to as low as 0.5% to 1% during low variability periods such as clear sky or overcast conditions. For wind farms, the degree of curtailment is expected to be lower as the short-term variability of wind power output is less than that of PV power output [16]. These curtailment levels reflect what might be required of semi-scheduled generators to meet dispatch targets and trajectories should the semi-scheduled classification be deleted (Option 2). However, it is important to note that this analysis was based on a flat dispatch level across the 5-minute dispatch period, rather than a linear ramp between dispatch levels, and also assumes a perfect forecast. As such, it only reflects the curtailment associated with mitigating VRE variability and not that associated with forecast or other uncertainties.

3.1.2 Curtailment required to avoid dispatch exceedance (Option 1)

If under-generation due to limitations in primary energy availability is permissible (Option 1), curtailment is only required if the semi-scheduled generator will exceed its dispatch trajectory. In this section, we present an analysis of curtailment and curtailed energy for three solar PV plant over 2016.

Causer Pays four second interval active power output data was compared to interpolated dispatch data. Curtailment was assumed to occur when the active power output of the solar PV plants exceeded the dispatch trajectory. This analysis incorporates dispatch trajectories based on linear ramps and therefore accounts for curtailment due to both VRE variability and uncertainty.

As with curtailment for firm dispatch, Figure 1(a)-(c) demonstrates that the amount of solar PV energy curtailed to prevent dispatch trajectory exceedance is largely driven by the weather conditions. The low and high generation days have a relatively high frequency of daily curtailment levels under 0.4 MWh/MW per day. This is to be expected as low and high daily generation typically occur during overcast and clear sky conditions, respectively. During these conditions, the PV plant active power output is highly predictable as the variability is low. However, the medium range of daily generation values, which could be expected to occur during partly cloudy conditions, could result in up to 0.85 MWh/MW per day of curtailment to prevent dispatch trajectory exceedance.

Figure 1(a)-(c) also suggests that over the long term, the curtailed energy of the solar PV plants can be material. The colour coded data points in Figure 1(a)-(c) show that 5% or less of daily energy production is curtailed for the high production days while more than 15% and up to 30% of daily energy production could be curtailed for medium to low production days. However, caution should be applied when interpreting the significance of the normalised curtailed energy as normalising a low value for curtailed energy against a low value for daily energy production will result in a large degree of curtailment.

Since high daily energy curtailment only occurs during medium to low production days and as these days are relatively infrequent, we expect that the costs of curtailed energy over the longer term will be manageable but material to market participants and project viability. For wind farms, the degree of curtailment is expected to be lower because the short-term variability of wind farm active power output is less than that of solar PV farm active power output [16].

3.1.3 Costs of curtailment may be manageable but material to participants

Curtailment will result in loss of revenue but based on our analysis, we expect this to be relatively small compared to other reasons for curtailment (e.g. due to network constraints) over the longer term. The degree of curtailment is driven by weather conditions and high production days appear to require lower degrees of curtailment for a semi-scheduled plant to follow a dispatch trajectory. Our analysis does not consider the opportunity cost or value of the energy, which depends on the energy spot price, financial contracts, and the contribution of semi-scheduled variability to Causer Pay factors. Periods of lower VRE generation are, of course, increasingly associated with higher prices due to the merit order effect. Therefore, we conclude that the costs of lost energy production to VRE in implementing the rule change options will not be large, but can be material to participants and project viability and should, along with the wider environmental consideration of spilled zero emissions energy, be considered in any changes to the rules.

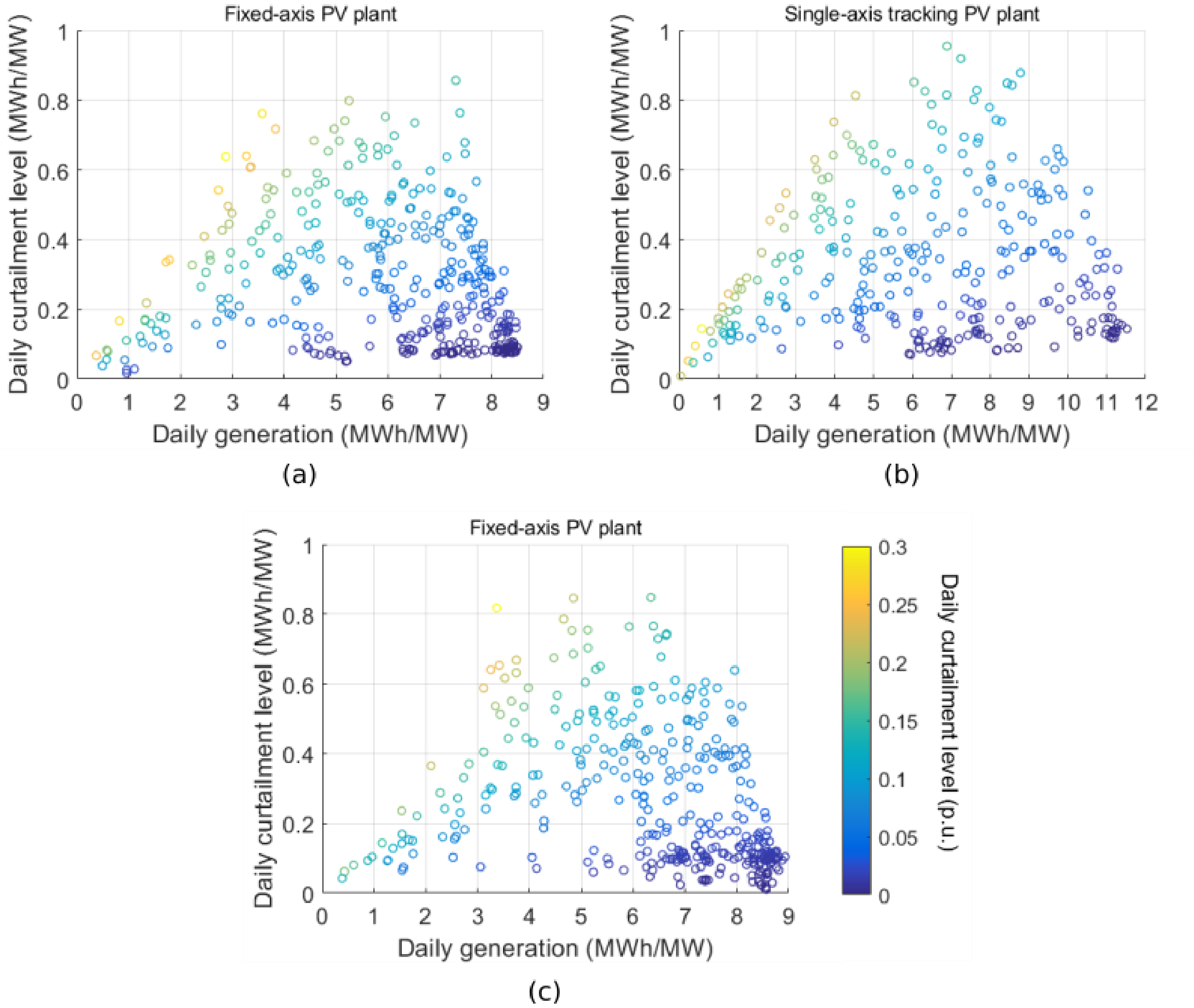

Figure 1: Daily energy curtailment calculated in MWh per MW of plant rated capacity compared with daily generation in MWh per MW of plant rated capacity for three solar PV plants. Daily energy curtailment per daily energy production (per unit) is colour coded

3.1.4 Determining dispatch conformance and fairness of costs

If either of the favoured options are to be implemented, AEMO and the AER should clearly outline how dispatch compliance will be defined. Analysis of curtailment costs outlined in Sections 3.1.1 and 3.1.2 did not permit any generation output beyond the dispatch level of the semi-scheduled generators. As discussed in Section 2.4, VRE generators can exercise precise control of their active power and comply with this requirement. However, as scheduled plant behaviour is currently deemed as conforming despite a similar magnitude of deviations in active power output from their targets (see Figure 2 and Figure 3), such a requirement would impose costs on VRE that would not be imposed on existing scheduled generation. As such, the AER and AEMO should ensure that dispatch conformance monitoring is fair across generation types to avoid inconsistencies and market distortion.

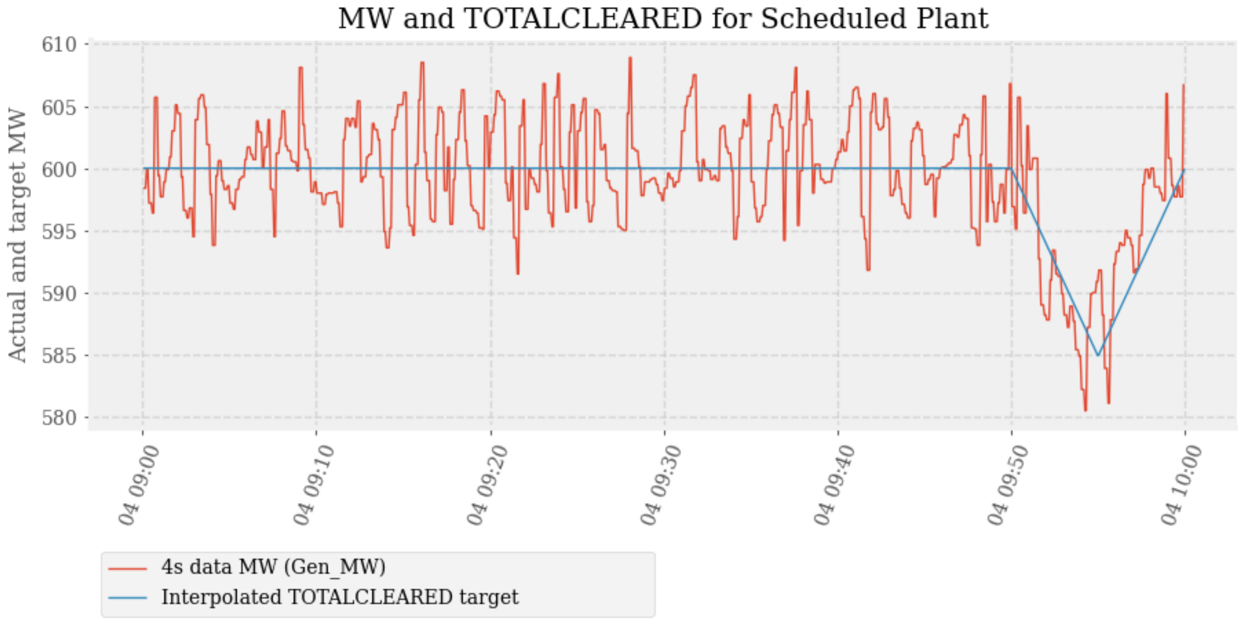

Figure 2: Active power output and dispatch targets for a scheduled plant between 9:00 and 10:00 on 4/7/2020. The scheduled plant is not providing raise or lower regulation FCAS

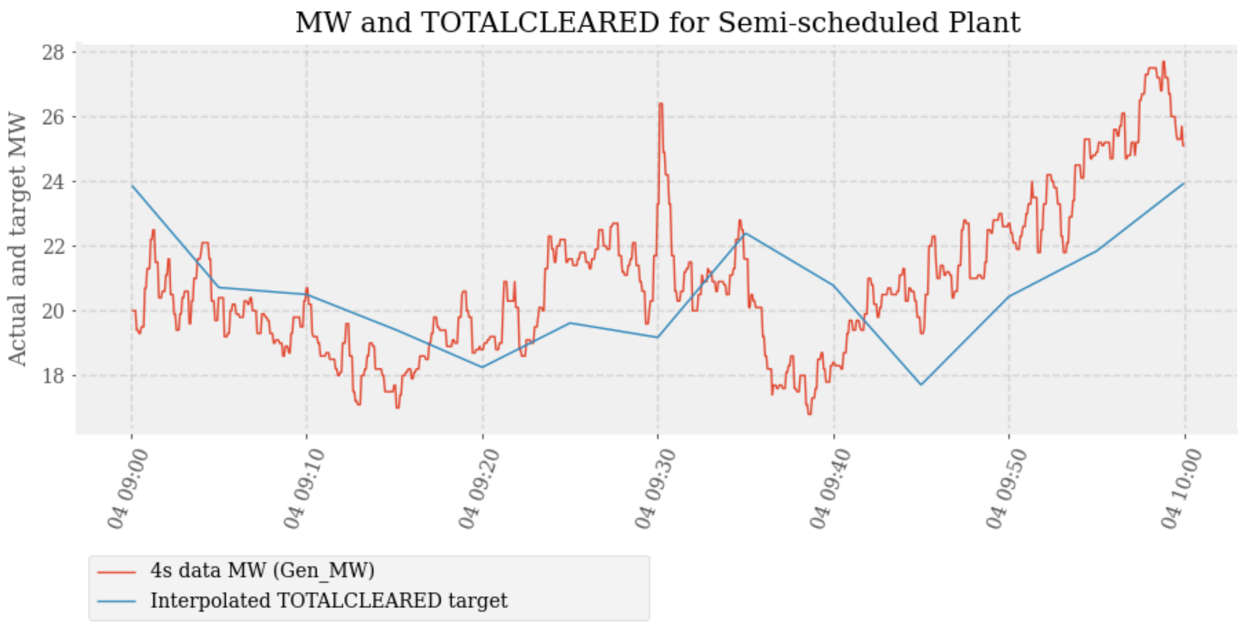

Figure 3: Active power output and dispatch levels for a wind plant between 9:00 and 10:00 on 4/7/2020

3.2 VRE generation forecasting accuracy

Maximising forecasting accuracy is paramount to realising the benefits of the favoured options whilst minimising impacts and costs to market participants and the power system. However, our analysis demonstrates that current forecasts are based on persistence forecasting that involves significant lags (up to one dispatch interval behind). The persistence forecast is based on the generation level up to 2 minutes before a dispatch interval starts and is required to be met at the end of the dispatch interval. Such an approach does not account for known changes across 7 minutes (e.g. changes in solar PV generation due to the position of the sun in the sky). The resultant errors may impose unnecessary costs on market participants and have further implications on central dispatch and frequency control.

We recommend that our analysis and forecast accuracy be further investigated by the AER and AEMO before, or in parallel to pursuing a rule change.

3.2.1 Forecasting methods at the scale of minutes

While numerical weather prediction models are used over longer timeframes, statistical methods that rely on historical wind, irradiance or active power data are typically used for minute-scale forecasting [17]. These statistical models are typically 'black-box' autoregressive models (e.g. AR, ARIMA), which apply weights to previous observations of wind/irradiance/active power to produce a forecast, or 'grey-box' machine learning models, which can easily incorporate many variables in addition to historical data [17]–[19]. If implemented correctly, these minute-scale forecasting methods should outperform a persistence forecast, a naïve method that assumes that the next observation will be the same as the last [19]. While persistence forecasts may be a good estimate where there is significant uncertainty in the forecast (e.g. during cloudy conditions), a persistence forecast can be improved using the methods discussed above or by accounting for known changes (e.g. changes in sun position).

3.2.2 AWEFS/ASEFS dispatch forecasting

Whilst AWEFS and ASEFS gathers data from a range of sources, AEMO documentation implies that persistence forecasts based on generator active power SCADA data are often used in dispatch. In addition to numerical weather prediction data and satellite data, AEMO collects SCADA data from wind and solar farms that is updated at a high frequency (4-10 s). Parameters that are sent to AEMO include active power output, wind speed and direction, temperature, humidity, pressure, solar irradiance (GHI, GII and DNI) and turbine/inverter availability [20].

While AEMO appears to collect a wide range of data at a high frequency, AEMO documentation suggests that when no constraints are applicable, the UIGF/dispatch level is determined using a persistence forecast based on active power output SCADA data [21]. For a given dispatch interval, input data up to two minutes before the end of the previous dispatch interval is used in the persistence forecast [21]. As such, AWEFS and ASEFS are forecasting the active power output of semi-scheduled generators at the end of a dispatch interval using data that is at least seven minutes old. Whilst persistence forecasts can be effective within shorter timeframes [19], a persistence forecast for active power output that is lagged by seven minutes may be inappropriate for determining binding targets.

3.2.3 Analysis of forecasting implemented in dispatch

An analysis of SCADA and dispatch data from plants operating in the NEM was carried out to determine whether a consistent lag was observable in the active power forecasts of semi-scheduled generators. For the week 1-7 July 2020, Causer Pays four second interval data, next-day dispatch data and intermittent generation forecast data were obtained using NEMOSIS [22] and NEMWeb. Active power output (Gen_MW) and active power target (GenSPD_MW) data were compared against linearly interpolated dispatch levels/targets (TOTALCLEARED). For semi-scheduled generators, these dispatch levels are either forecasted by AWEFS/ASEFS, or more recently may be self-forecasted. The forecast used for each dispatch interval for a semi-scheduled interval is available in the intermittent generation dispatch forecast data. This can either be specified as AWEFS_ASEFS, a participant ID or another vendor.

AWEFS/ASEFS forecasts lagging active power output can be observed by looking at dispatch and SCADA data over a day. Figure 4 and Figure 5 clearly show that the interpolated dispatch levels forecasted by AWEFS/ASEFS (blue line) lag the active power output data (red line). The validity of the data processing was confirmed by ensuring that SCADA active power targets (where available) corresponded to dispatch levels for each interval and by confirming that scheduled generators appeared to follow their dispatch targets (Figure 6).

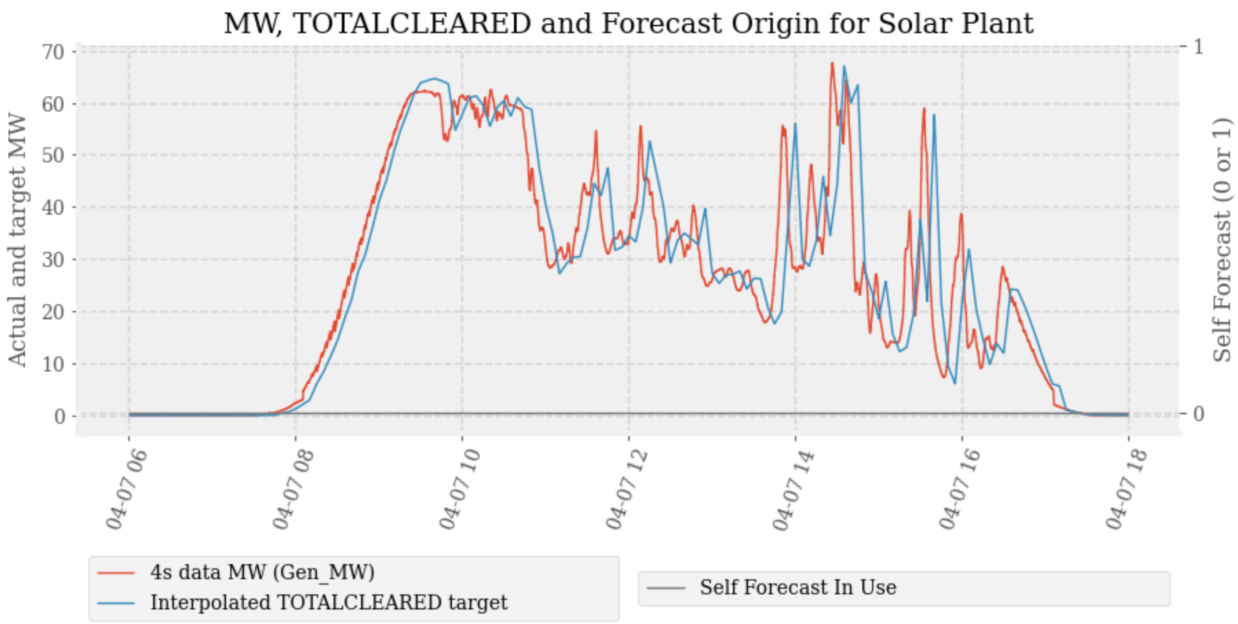

Figure 4: Active power output and dispatch levels and trajectories determined by ASEFS for a solar plant on 4/7/2020

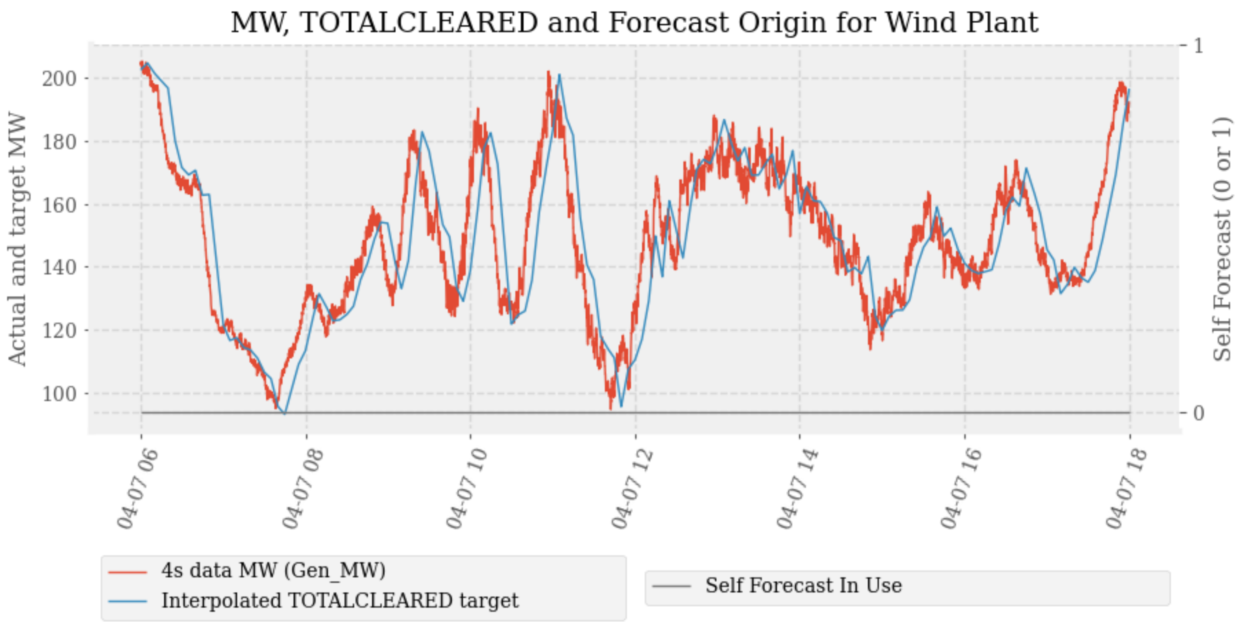

Figure 5: Active power output and dispatch levels and trajectories determined by AWEFS for a wind plant on 4/7/2020

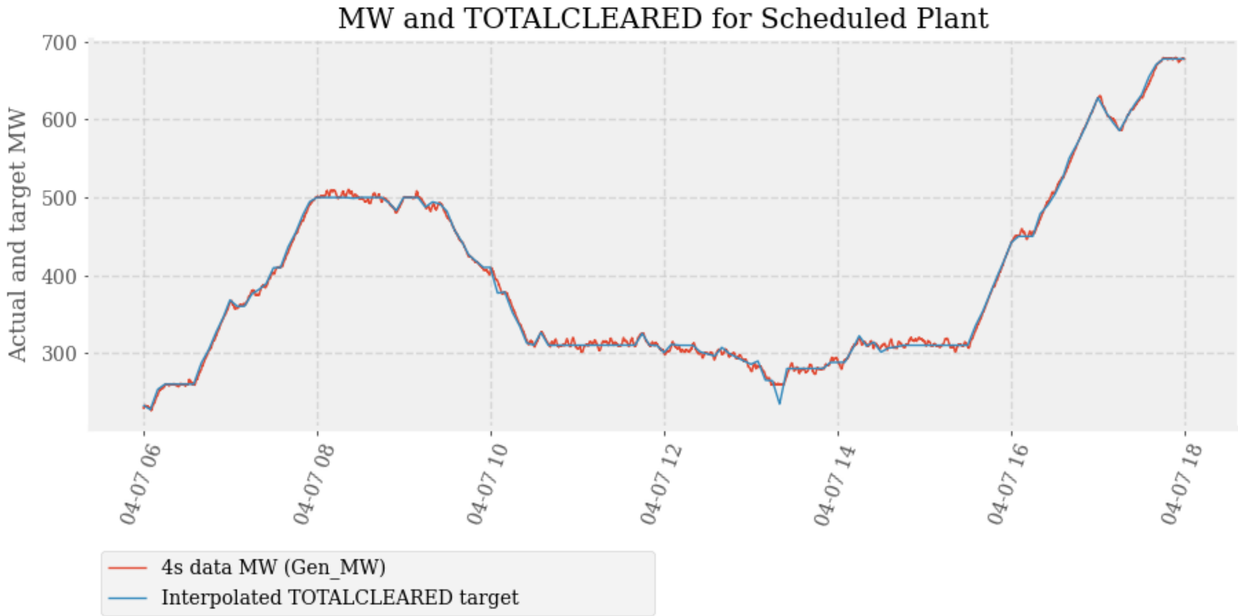

Figure 6: Active power output and dispatch levels and trajectories for a scheduled plant on 4/7/2020

A lag analysis was carried out to determine if lagged persistence forecasts were in widespread use. For each day in the week of 1-7 July 2020, the SCADA active power output of dispatched semi-scheduled and scheduled generators was lagged in increments of 30 seconds up to a total lag time of 600 seconds or 10 minutes. A root-mean square error (RMSE) was calculated between each of the active power lags and the generator's interpolated dispatch targets/levels. The distribution of 'optimal' lags (i.e. the active power output lag increment with the lowest RMSE) was then determined for each fuel type and for each day (Table 1). As an example, results for 3 July 2020 are shown in Figure 7 and Figure 8.

The normalised RMSE between active power and interpolated dispatch with a lag of between zero and 600 seconds applied is shown for different types of plants on 3rd July in Figure 7. The parabolic shape of the wind and solar RMSE curves suggests that a lag is present and justifies the choice of an optimal lag. The density of optimal lag for solar and wind in Figure 8 and the median optimal lag for solar and wind for each day in the week in Table 1 suggest that a large proportion of dispatch levels are a result of a lagged persistence forecast. Whilst Table 1 shows that the median lag for solar varies more than that for wind over the study period, the results demonstrate that a lag of 5-7 minutes is present in the forecasts.

Date	Battery storage	Fossil	Hydro	Solar	Wind
01/07/2020	0	0	0	420	420
02/07/2020	0	0	0	390	420
03/07/2020	0	0	0	390	420
04/07/2020	0	0	0	300	450
05/07/2020	0	0	0	420	450
06/07/2020	0	0	0	375	420
07/07/2020	0	0	0	360	420

Table 1: Median optimal lag in seconds for each day and fuel type

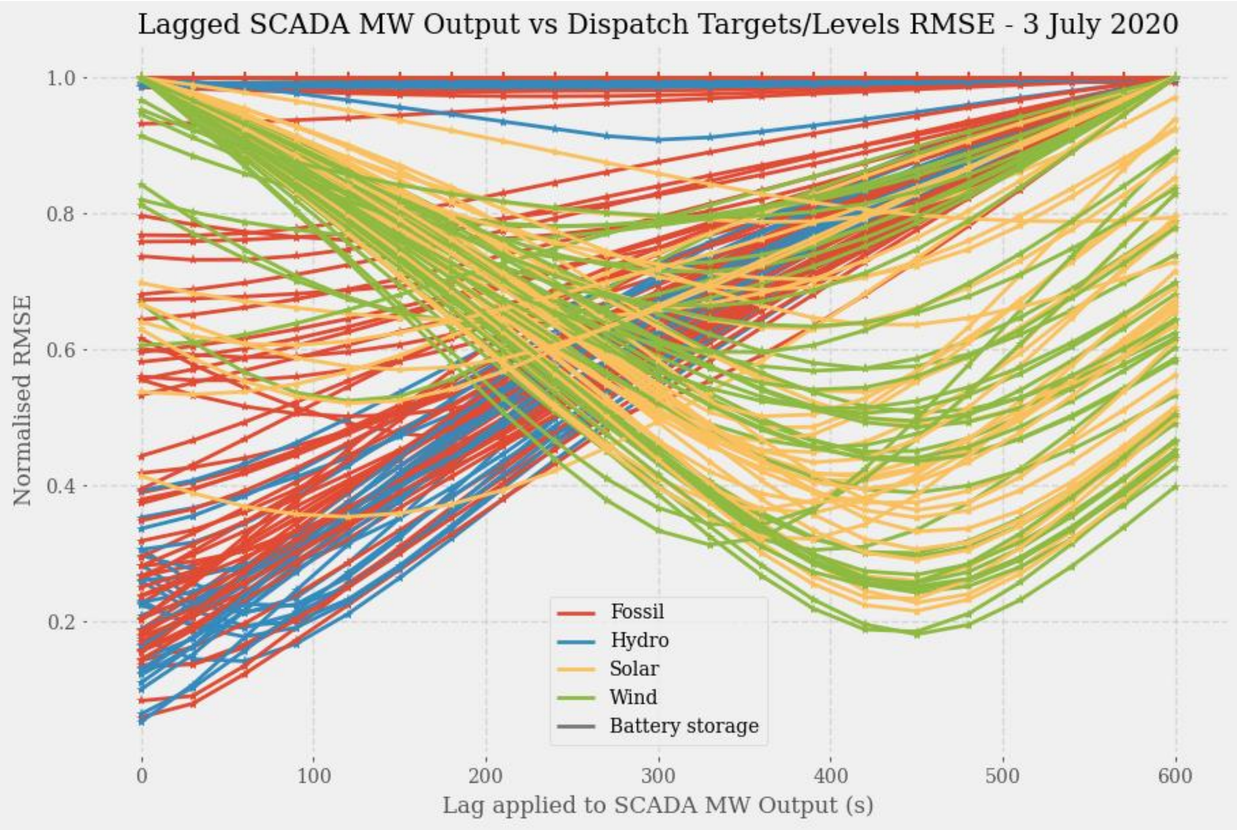

Figure 7: Normalised RMSE between lagged active power output and interpolated dispatch levels by generator fuel type for 3 July 2020. Each line represents a dispatched scheduled or semi-scheduled generator

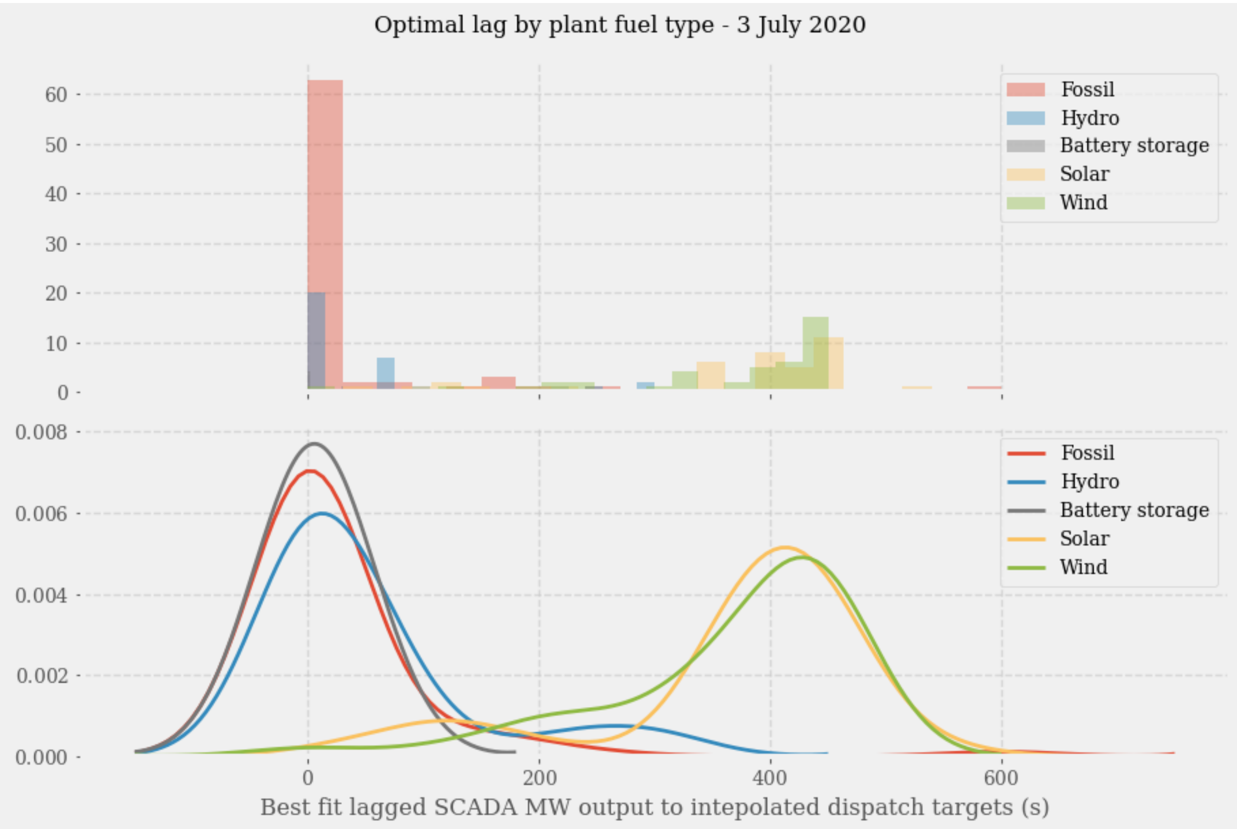

Figure 8: Active power output and dispatch levels and trajectories determined by ASEFS for a solar plant on 4/7/2020

3.2.4 Self-forecasting

While the lag analysis did not differentiate between dispatch levels determined by AWEFS/ASEFS and those determined by self-forecasts, preliminary inspection of self-forecasting in dispatch indicates that they too display a persistence lag. Figure 9 shows that the self-forecast for the solar plant was fairly accurate during what is presumed to be clear sky conditions until a sudden change in active power output, after which the self-forecast lags and the forecast origin reverts back to ASEFS. Figure 10 shows the consistent lag of a wind plant self-forecast. It is unclear if these observations are products of the underlying self-forecast models or AEMO's implementation of participant self-forecasts.

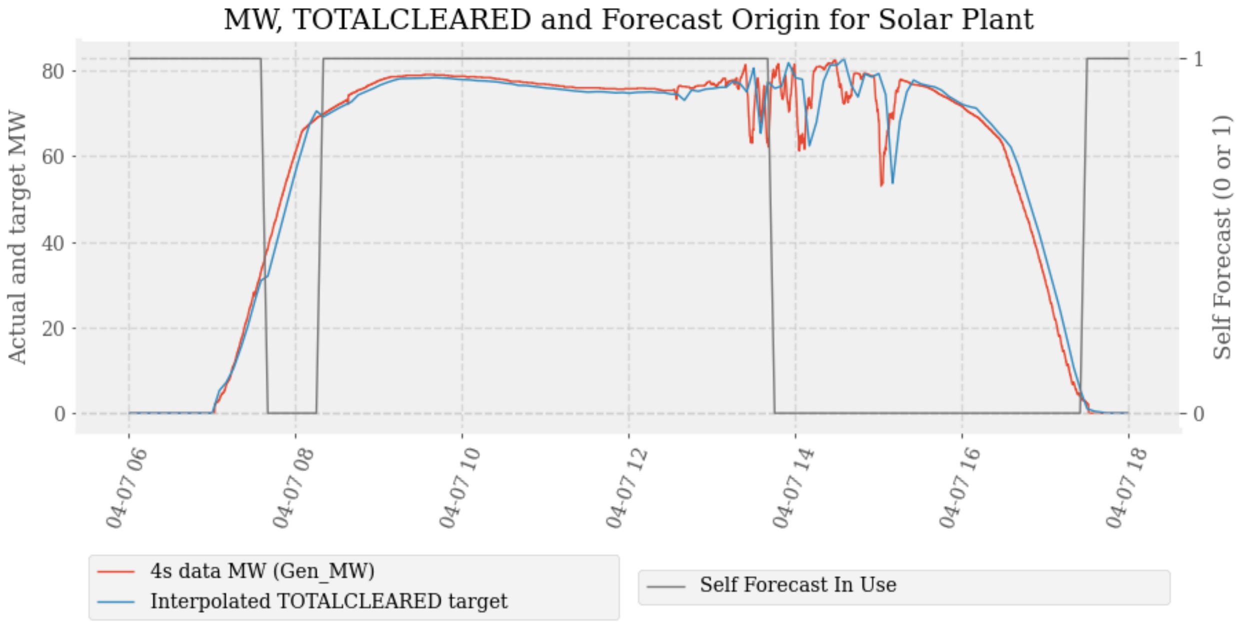

Figure 9: Active power output and dispatch levels and trajectories determined by self-forecast for a solar plant on 4/7/2020

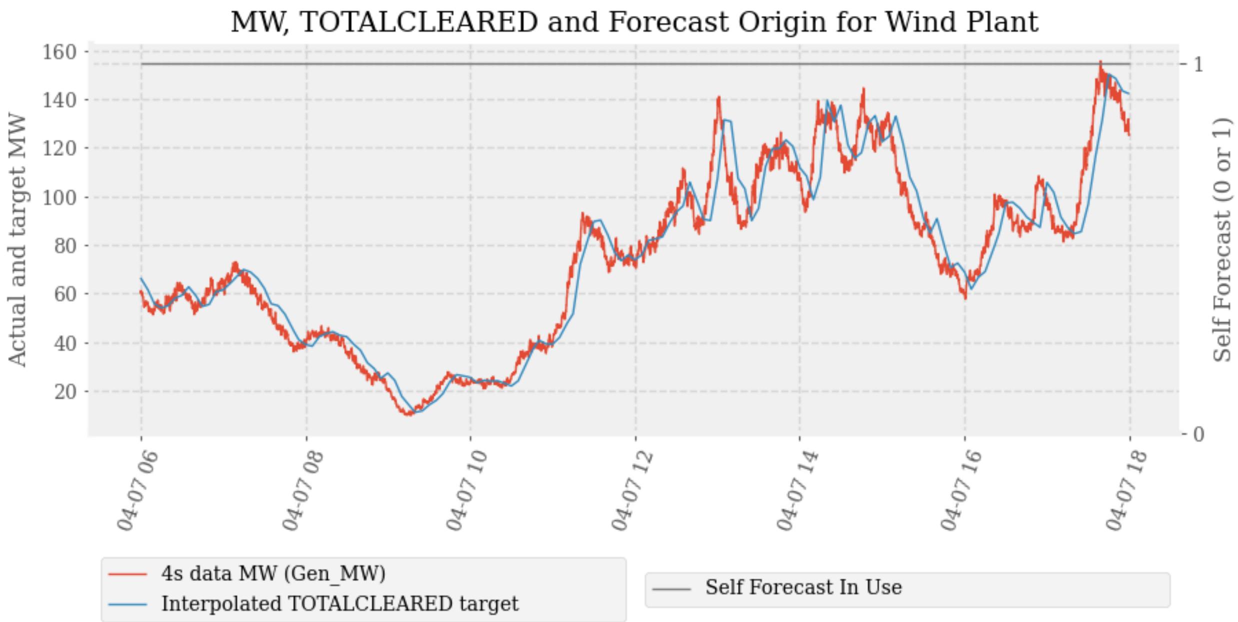

Figure 10: Active power output and dispatch levels and trajectories determined by self-forecast for a wind plant on 4/7/2020

3.2.5 Forecast lag and dispatch

The use of persistence forecasts with significant lags (5-7 minutes, or at least one dispatch interval behind) will reduce the benefits associated with the favoured options proposed in the Issues paper. Conformance to lagged dispatch levels may lead to avoidable energy spill or missing energy, particularly during minute-scale active power output ramps. This will create unnecessary revenue losses for semi-scheduled market participants and may have further implications on the accuracy of central dispatch and frequency control. As such, we recommend that forecast accuracy be further investigated by the AER and AEMO before, or in parallel to, pursuing a rule change. Furthermore, given the breadth and frequency of data being collected by AEMO, it is conceivable that the accuracy and sophistication of AWEFS and ASEFS can be improved. AEMO should also publicly publish more detailed assessments of AWEFS/ASEFS methods and outcomes to assist all stakeholders in contributing to potential improvements in their performance. Such improvements would reduce the costs borne by participants and improve the accuracy and efficiency of the central dispatch process.

3.3 Interaction with Causer Pays

Causer Pays has several shortcomings but deleting the classification of semi-scheduled generation (Option 2) would better align (dis)incentives for VRE generators with central dispatch objectives. Amending the dispatch rule for semi-scheduled generation (Option 1) would result in a persisting disconnect and inconsistency in the rules and liabilities across generators in the NEM. In considering the favoured options, the AER should take the interaction of each option with Causer Pays into account.

3.3.1 A weak disincentive

The intention of the Causer Pays methodology is to allocate regulation FCAS costs based on cost-causation [4]. For scheduled generating units and loads and semi-scheduled generating units, an active power output deviation is calculated as the deviation from a linear ramp from a previous dispatch target/level to the next dispatch target/level. The deviation is weighted by the Frequency Indicator (FI), a measure of the volume of regulation service required at the time of deviation [23].

Causer Pays is a weak disincentive for market participants to adhere to dispatch trajectories. The process involves a *post-hoc* contribution factor calculation that aggregates an individual unit's factors over 28 days and then over a market participant's generation portfolio [23]. The AER has recognised this weakness in Causer Pays in the Issues paper, suggesting that the current calculation methodology "disconnects contextual coincidence". We agree with the AER that a major overhaul of Causer Pays is required to better strengthen and align (dis)incentives but that this would have consequences beyond addressing the motivations of the Issues paper.

3.3.2 Disconnect for semi-scheduled generation and an inconsistency

As it currently stands, the Causer Pays calculation creates a disconnect between the dispatch obligations and cost-causation liabilities of semi-scheduled generators. Semi-scheduled generators are exposed to liabilities due to Causer Pays, which assumes the unit is following a dispatch trajectory, when they are not required to follow a dispatch trajectory during an interval that is not a semi-dispatch interval [1]. The disconnect here is that a liability is incurred by semi-scheduled generation for something they are not expected to do by the Rules. This contrasts with scheduled generators that are expected to follow a dispatch trajectory and are penalised for minor deviations from this trajectory through Causer Pays. The combination of this disconnect and inconsistency across generation classifications means that the (dis)incentives, regardless of whether they are effective or not, are not coherent with market and power system objectives.

3.3.3 Potential Causer Pays reform

An open rule change on primary frequency response may exempt capable VRE generators from Causer Pays liabilities and eliminate the disconnect issue, but also increase the need for regulatory measures to ensure dispatch target conformance. Changes to the Causer Pays calculation proposed by AEMO in *Primary frequency response incentive arrangements* (ERC0263) would remove any Causer Pays liabilities for a plant if it is determined to comply with AEMO's Primary Frequency Response Requirements [24]. If implemented, the Causer Pays disconnect will no longer be an issue for PFRR-compliant semi-scheduled generators. However, should ERC0263 be implemented without the implementation of either Option 1 or 2, PFRR-compliant semi-scheduled generation will no longer face any disincentives for sudden ramping or responses to negative prices.

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