Submission

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To	AER
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Subject Issues paper – Semi scheduled generator rule change(s)

Overview:

Infigen Energy (Infigen) welcomes the opportunity to make a submission. Infigen delivers reliable energy to customers through a portfolio of wind capacity across New South Wales, South Australia, Victoria and Western Australia, including both vertical integrated assets and Power Purchase Agreements (PPAs). Infigen also owns and operates a portfolio of firming capacity, including a 123 MW open cycle gas turbine in NSW, a 25 MW / 52 MWh battery in SA, and will soon take ownership of 120 MW of dual fuel peaking capacity in SA. Our development pipeline has projects at differing stages of development covering wind, solar and batteries and we are also exploring further opportunities to purchase energy through capital light PPAs. This broad portfolio of assets has allowed us to retail electricity to over 400 metered sites to some of Australia's most iconic large energy users.

The AER has presented a number of issues in relation to the operation of semi-scheduled resources in the National Electricity Market (NEM). The AER has proposed two "preferred options" which involve: eliminating the semi-scheduled classification; or requiring semi-scheduled units to attempt to meet a forecast target at all times. However, these solutions appear to be attempting to solve multiple problems through a single regulatory mechanism rather than seeking the most efficient response (regulatory or market).

The semi-scheduled classification was designed to reflect the underlying resource and capabilities of renewable energy sources. A market design that reflects these capabilities will be critical to ensuring low cost decarbonized energy supply for Australian energy consumer. In other words, the market should be adapted to new technologies, rather than attempting to 'force' technologies to follow the market. The AER's preferred options would potentially lead to costly outcomes for both generators and consumers that Infigen does not consider would be consistent with the NEO. Several of the issues identified by the AER are already under investigation by the AEMC as part of a comprehensive package of rule changes related to system security.

Infigen agrees that change to the Market Rules, as they related to semi-scheduled resource operation, may be required. We have broken down the issues identified by the AER into three distinct problems, each of which may require a different response, as summarised in the table below. Further details are provided in this submission.

Issue	Infigen response
The Rules permit (and existing market design provides a financial incentive for) semi-scheduled generators to behave in a way that may put system security at risk	Infigen considers that a relatively simple change to the National Electricity Rules should be made to address the first point: requiring semi-scheduled units to make best efforts to generate at their available resource unless receiving a dispatch instruction from AEMO. Effectively, semi-scheduled generators would not be permitted to voluntarily reduce output below their fuel or plant availability *unless* instructed by AEMO (including through a dispatch instruction). This is effectively the approach taken by New Zealand policy makers. Conversely, the approaches proposed by the AER would be costly and may actually increase the need for ancillary services.
Some semi-scheduled generators are not following linear trajectories which may increase the need (or usage) of Regulation services	While this proposal may increase the utilisation of Regulation services, it is important to specify what system security issue this presents. Regulation services are designed to be frequently utilised and remunerated for their response. The Causer Pays methodology, even in its current design, ensures that those not attempting to ramp linearly pay proportionately more to recover the cost of these services. Changes to generator technical standards in late 2018 have also meant that new semi-scheduled plants will now linearly ramp during semi-scheduled periods. Therefore, we believe that the impact from generators not following a linear trajectory during constraints will not increase with increased installed capacity of semi-scheduled generators, and that ancillary services required to rectify this impact will not increase. Infigen's analysis also concludes that as installed capacity of semi-scheduled increases, the over and under generation throughout the interval will continue to broadly offset each other. Net system

	deviation from the linear trajectory of semi-scheduled units should remain low. Constraining generation to the trajectory would cause a bias of deviation to below the forecast, therefore requiring additional ancillary services (FCAS Regulation Raise and Primary Frequency Response). This could lead to unnecessary increases in both semi-scheduled generator LCOE (and hence energy prices) and FCAS Raise Regulation costs, which may not be consistent with the NEO.
Variability and ramping requirements are likely to increase over time, which may require additional flexible resources	Infigen expects that the NEO can best be met when services are well defined, with the most capable and economic participant delivering a service. The AER and AEMO have not identified a market failure that would present a risk to reliability or system security, or require semi-scheduled generators to always meet a dispatch target. The existing FCAS services market, combined with tight deadband Primary Frequency Control, appear sufficient to allow AEMO to procure sufficient resources to meet a consumer-led Reliability and Frequency Operating Standard. It is therefore appropriate to use market frameworks to procure the most efficient response, which may or may not be from semi-scheduled generators curtailing output. Frequency control and Causer Pays frameworks are currently being addressed by the AEMC and ESB through a package of rule changes, including Infigen's Operating Reserves and Fast Frequency Response proposals. Critically, semi-scheduled generators already have the opportunity to reduce their output (and hence their Causer Pays factors) if least-cost to do so – as with all generators and customers.

1. Identification of the problems

1.1 Rapid ramp during negative price intervals

Existing semi-scheduled renewable generators typically seek to maximise production in all periods when prices exceed their short-run marginal cost, which is typically zero to ~$3/MWh *minus* any priced carbon externalities, such as LGCs.

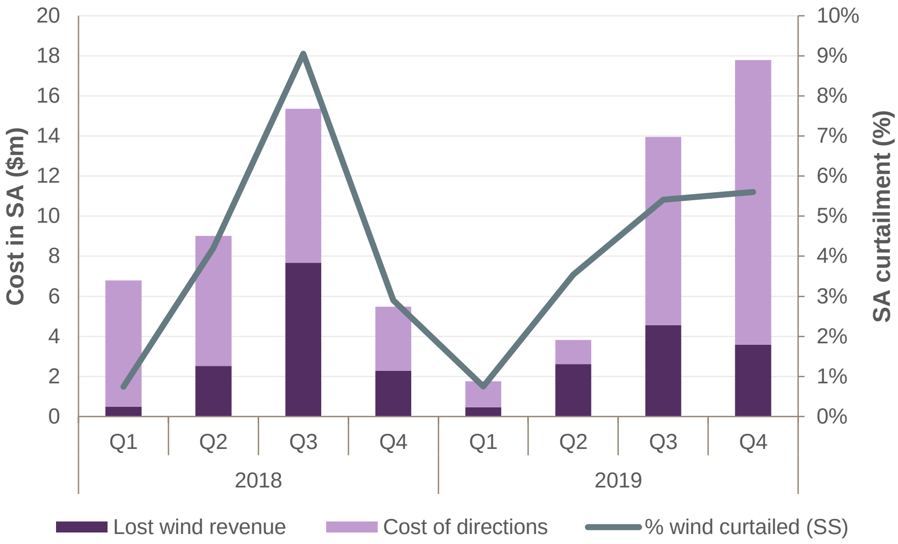
However, VRE may also have incentives to bid below their SRMC to avoid being curtailed due to broad system constraints, such as the current system strength constraints in South Australia.[1] Specifically, projects have a rational economic incentive to bid at the price floor despite having a preference to run at higher prices. It is important to note that installation of synchronous condensers is likely to significantly alleviate these constraints.

Figure 1 shows the estimated curtailment of wind in South Australia due to the SA system strength constraints[2]. The cost of this curtailment is indicatively calculated by the marginal SA price in each half-hour, plus the SA direction costs. The analysis shows that the delay in procuring synchronous condensers to overcome system strength constraints has already cost $11m to $13m per year in lost revenue in South Australia plus $23m to $26m in direction costs, which does not include the cost of project delays and potential higher future costs. Infigen considers that addressing these system strength constraints should be the market bodies' highest priority due to their significant cost and distortionary impacts.

[1] There is currently regularly limits on total VRE production in South Australia. AEMO chooses who to be curtailed based on generator bids – with higher bids being curtailed first. Therefore, any project bidding above the price floor will be the first to be curtailed (potentially for their entire output) – while all projects at the price floor will "share the pain" and be allocated a share of curtailment.

[2] To estimate the impact of the system strength constraints specifically, this analysis is restricted to periods of curtailment when SA wind availability exceeds 1000 MW and the SA price is above $0/MWh.

Figure 1 Cost of system strength constraints in South Australia



Source: AEMO, Infigen analysis

While semi-scheduled generators rightly are not required to meet their forecasts when the energy resource is unavailable, units also currently have no requirement to produce at their full availability. During periods of unexpected negative pricing, units can therefore be incentivised to reduce their output below their availability despite not receiving a dispatch instruction. We note that incentives for this behaviour may become even sharper under 5 Minute Settlement (

Figure 2).

Figure 2 Impact of 5 Minute Settlement

Trading Interval	Dispatch Interval	Dispatch Price ($/MWh)	MW output Semi-Scheduled Generation (with manual curtailment inside DI)	MW output Semi-Scheduled Generation (w/o manual curtailment inside DI)
0:00	0:00	50	100	100
	0:05	-1000	100	0
	0:10	0	0	0
0:30	0:15	0	0	0
	0:20	0	0	0
	0:25	0	0	0
	0:30	0	0	0

	30 Minute Settlement Market ($)	5 Minute Settlement Market ($)
Cost without Curtailment	-1388.9	-8333.3
Cost with Curtailment	0	0
Benefit to consumer	1388.9	8333.3

We agree with the AER that this could ultimately lead to system security issues. At the extreme, the rapid curtailment of a significant portion of the generation fleet within a dispatch interval could lead to a shortfall of generation.

We consider that this is a material issue that should not be left to market signals, and a regulatory solution is required. This is discussed further in Section 2.

1.2 Linear ramping between dispatch intervals

The AER has also identified instances where semi-scheduled generators do not ramp (or attempt to ramp) linearly to a dispatch cap; rather they move immediately to their target. In Western Australia, this behaviour has led to significant ancillary service requirements (for example Figure 3), but without any system security implications.

Figure 3 Contribution of immediately moving to target instead of linear ramping ("BMO ramping") to Western Australian load following (regulation) costs in 2014[3]

Table 9.4 – ROAM's percentile estimates for LFAS needed based on the full year of data

Percentile	Load forecast error	NSG forecast error	Deviation from dispatch	BMO ramping	Total net
99.95%	-106	-83	-62	-101	**-130**

Note that regulation (LFAS) required for non-linear ramping is comparable to load forecast error

We also note that new generators are required to have the capability of linear ramping between two semi-dispatch cap targets. Existing generators may not have this capability, but would continue to receive a price signal through the Causer Pays framework (as well as any future obligations). Step change ramping may be a misguided attempt to "better" follow dispatch instructions.

We acknowledge that resources have an incentive to ramp more quickly than a linear trajectory for best economic outcomes during price events. However, this is not restricted to semi-scheduled generators, and while deviations are financially penalized through Causer Pays, in our view persistent and deliberate deviations from intended behaviour is not consistent with the current National Electricity Rules, and it would be appropriate for the AER to investigate such behaviour.

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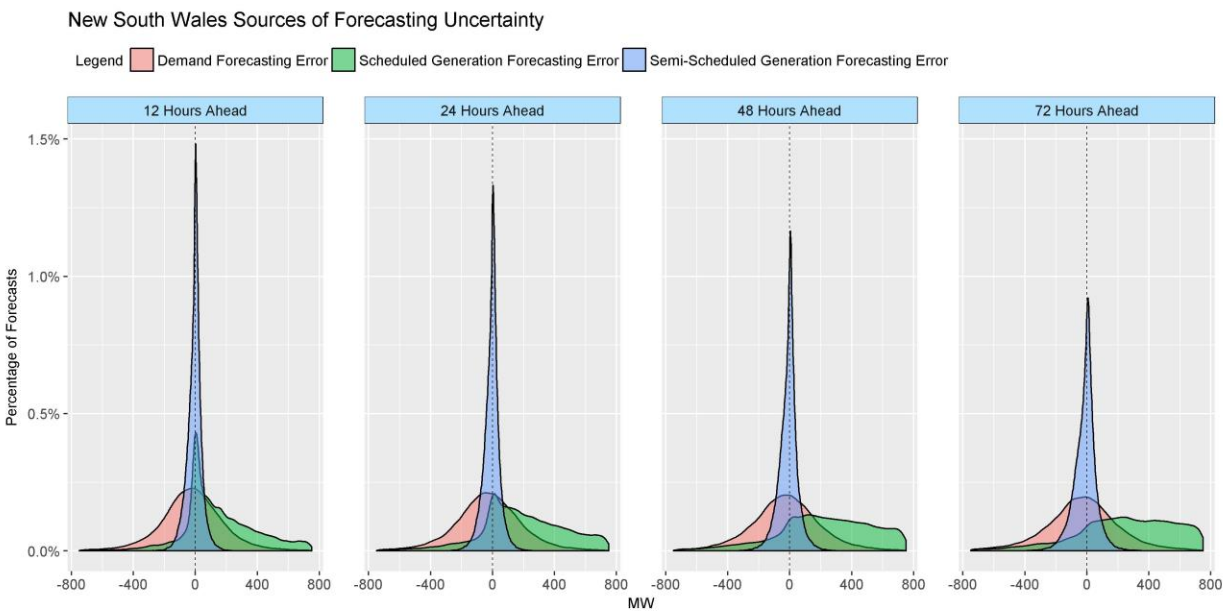
[3] https://www.erawa.com.au/cproot/14768/2/ROAM%202014%20Ancillary%20Service%20Standards%20and%20Requirements%20Study%20Draft%20Report.pdf

1.3 Increased variability

The AER has also reported on analysis by AEMO on the potential ramping requirements of VRE, leading to the need for more flexible resources (for forecasted ramps) and a growth in the quantity of ancillary services (for unforecasted ramps and variability within a dispatch interval). These issues have been identified by market operators since at least 2010. Notably, variability from scheduled generators and from demand is also a significant source of uncertainty (**Error! Reference source not found.**).

Figure 4 Typical error distributions for a range of forecasting horizons [4]



Source: AEMO

This is a distinct issue separate from manual or programmed responses to prices.

The AER has suggested options which would require semi-scheduled generators to cap their output at their forecast level, rather than relying on market signals. This seems an extreme and costly response, and does not reflect efficient market design. Where possible, explicit services should be defined and procured, rather than achieved through mandatory requirements.

The NEM market design already recognises that it is more efficient to define and procure a separate service for balancing supply and demand within a dispatch interval (Regulation FCAS) and allocate those costs to those who cause the need (Causer Pays). This allows for the most efficient (least-cost) utilisation of available resources – which could include semi-scheduled generators *or* loads curtailing their output to better match a nominal linear forecast trajectory *if* it is more efficient for them to do so.

4 https://aemo.com.au/en/consultations/current-and-closed-consultations/consultation-on-initial-version-of-reserve-level-declaration-guidelines

Within this basic framework, it is appropriate to review how these services are procured, and whether alternative or additional services are required. Appropriate services for managing both variability and uncertainty, including the existing Causer Pays framework, are already being considered by the AEMC as part of a package of rule changes which includes Infigen's Operating Reserves proposal as well as AEMO's rule change on incentives for frequency control. Similarly, the ESB is considering whether existing "essential services" are sufficient and appropriate. We therefore consider that this aspect of the AER's paper is already well covered by existing rule changes.

1.3.1 Cost implications

Requiring semi-scheduled generators to cap their output to a forecast at all times will have a material impact on the cost of production. Infigen has undertaken analysis of AEMO forecasts versus actual production, and the reduction in energy that would be required. This shows that historical curtailment of wind would be 2.4-4% and of solar by 3-6% (Figure 5 and Figure 6). These deviations can reflect underlying forecasting errors as well as transitory high or low resource periods (e.g., wind gusts or moving cloud cover).

Figure 5 Lost energy due to curtailing generators to a forecast

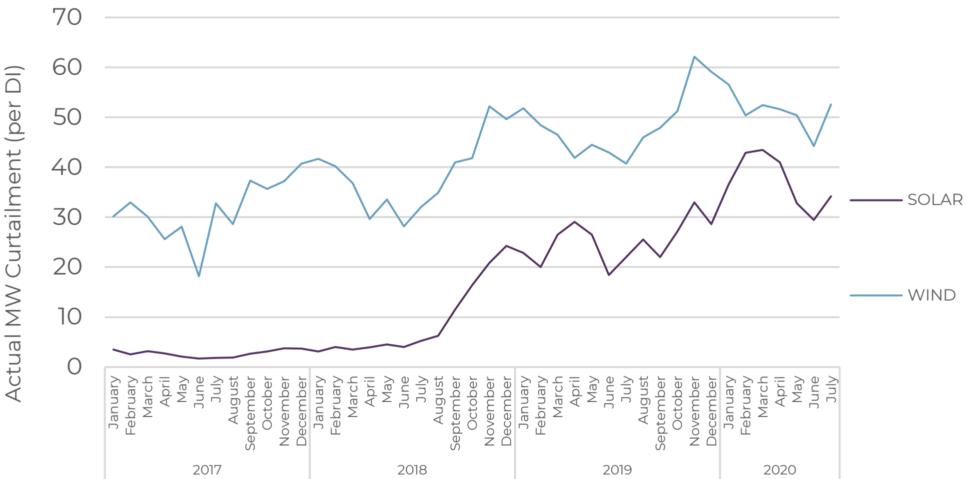
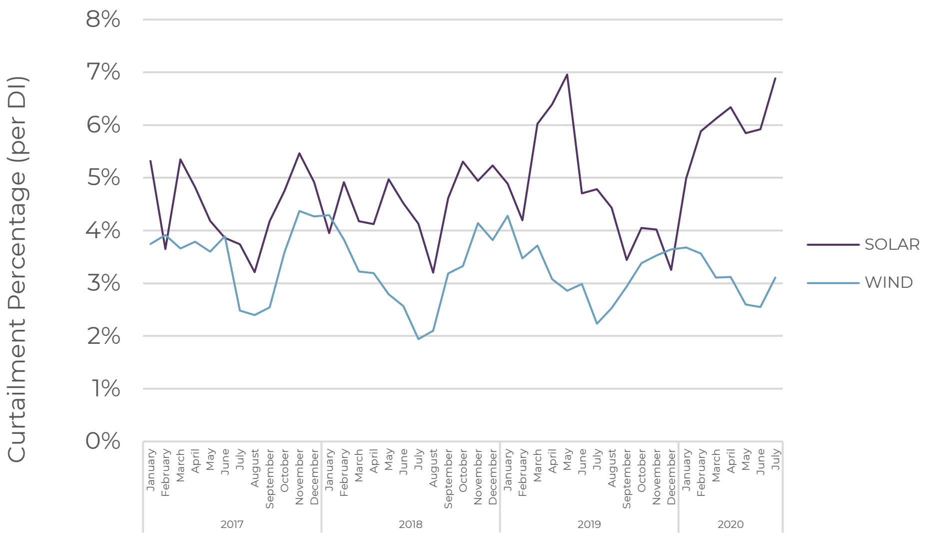


Figure 6 Lost energy due to curtailing, as a percent of dispatched semi-scheduled generation



The AEMC recently made a temporary rule requiring a mandatory primary frequency response from all capable participants. Therefore, a curtailed wind farm would typically relax that curtailment when frequency was low (i.e., there was a shortfall of generation). Actual curtailment would therefore be roughly half this level.

This would have a material impact on the cost of wind and solar energy. A 2-3% reduction in energy would increase the levelised cost of energy production by $1-2/MWh. This will inevitably be reflected in wholesale prices – with a $1/MWh increase in wholesale prices equivalent to $180m/year in increased energy costs for consumers.

1.3.2 Implications for frequency control

An unintended consequence of *requiring* semi-scheduled generators to curtail output when exceeding their forecast is that this may actually reduce frequency performance.

Currently, the diversity of wind and solar resources means that "unders and overs" often cancel out. Historically, the average *net* deviation from forecast for semi-scheduled generation is approximately zero (the green line in Figure 7). Notably, in 2017 – 2018 the net deviation from forecast was approximately 2-4 MW, compared to a total of 5 GW of installed capacity. This has now increased to approximately 5-7 MW, compared to a total of 10GW installed capacity. This demonstrates that the net deviation remains negligible (at ~0.06% of installed capacity) even with significantly increasing proportions of semi-scheduled generation. In other words, unders and overs on various units tend to cancel out on average, although net deviations may be above or below at any time.

Figure 7 also shows the 10^{th} and 90^{th} percentile of dispatch deviations from target (~70 MW below the forecast, and ~50 MW above the forecast). These deviations are one component of the Regulation FCAS requirement, with costs recovered from generators through Causer Pays. Notably, these costs have not increased significantly despite material renewable capacity installation growth.

Figure 7 Deviations in semi-scheduled generation across the NEM over time

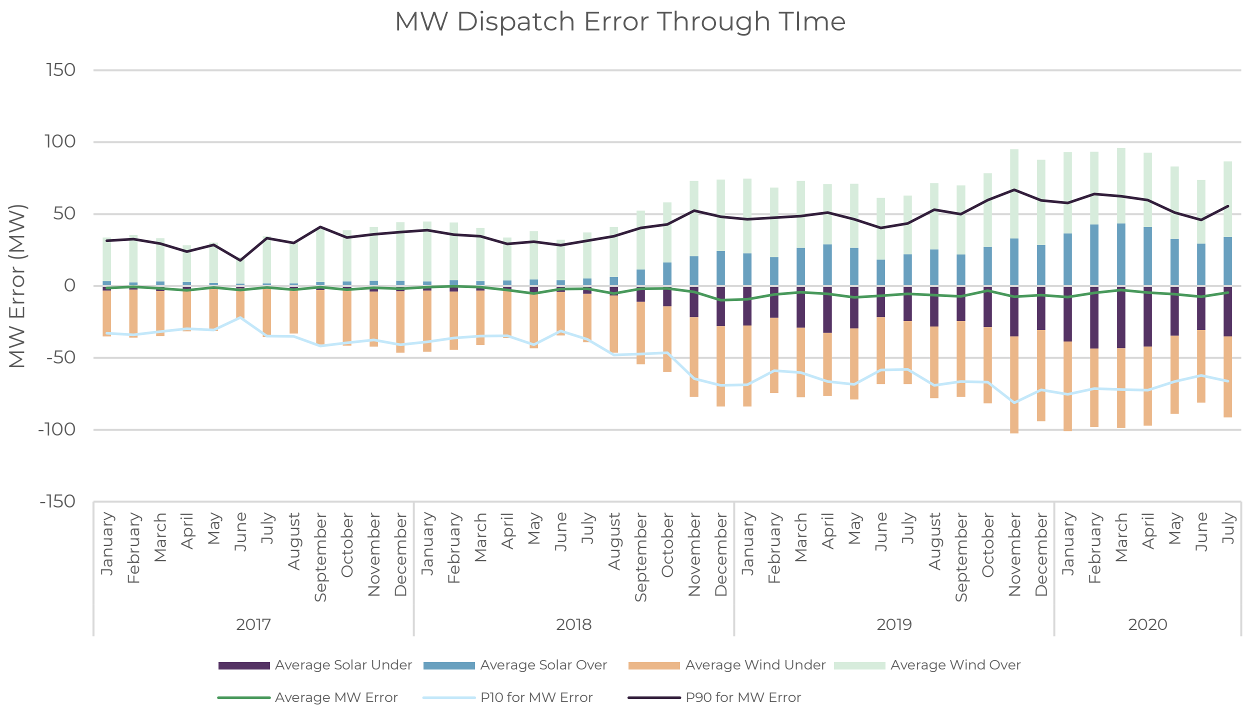
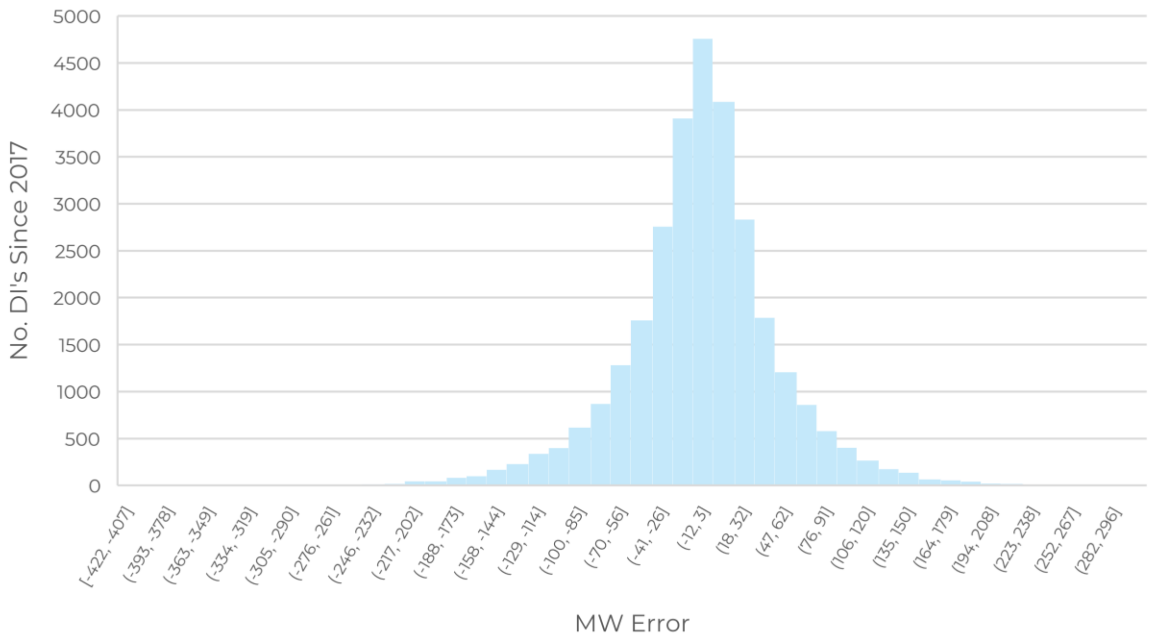


Figure 8 Histogram of Dispatch Interval's total MW error at Semi-Schedule Generators.



Curtailing the "overs" would result in a net-negative deviation, as shown in Figure 9 and Figure 10, requiring constant response from an ancillary service – either Regulation or Primary Frequency Control. Critically, curtailment would require greater Raise quantities of these services, with 10% of dispatch intervals since August 2019 having a -177 MW deviation from the forecast. A rule change that *causes* additional net-deviations may not be efficient, and not all semi-scheduled units may not be best placed to continually adjust output, potentially requiring further resources (and costs).

Figure 9 Deviations in semi-scheduled generation if generation above forecast is prevented

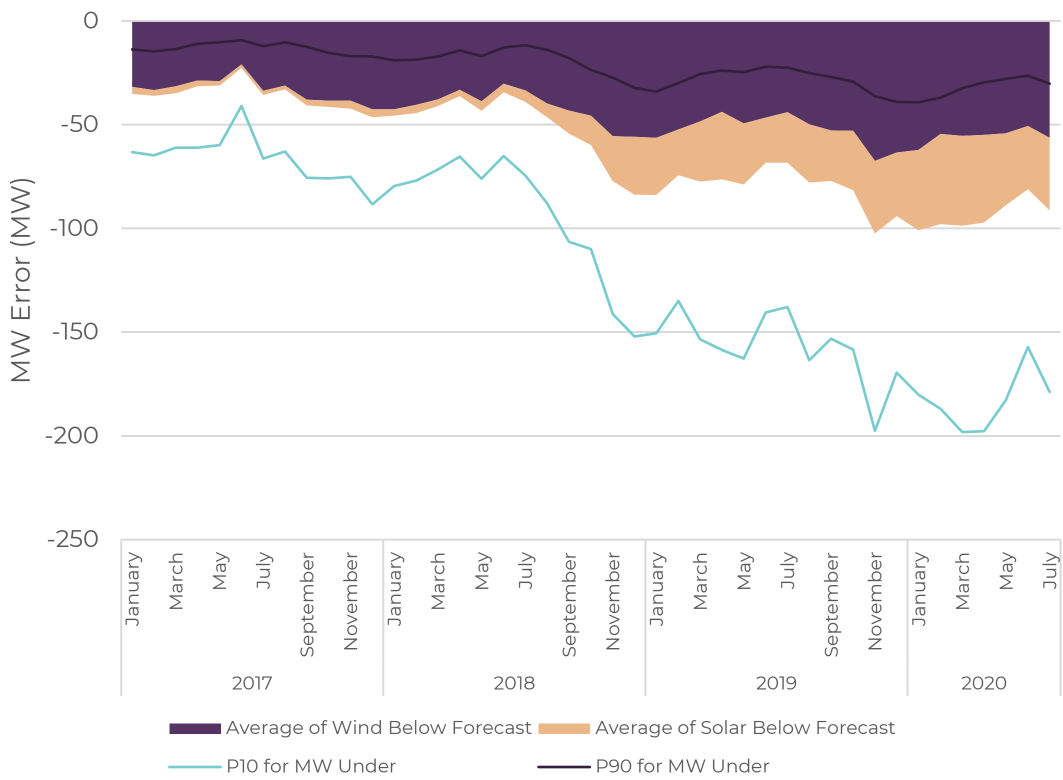
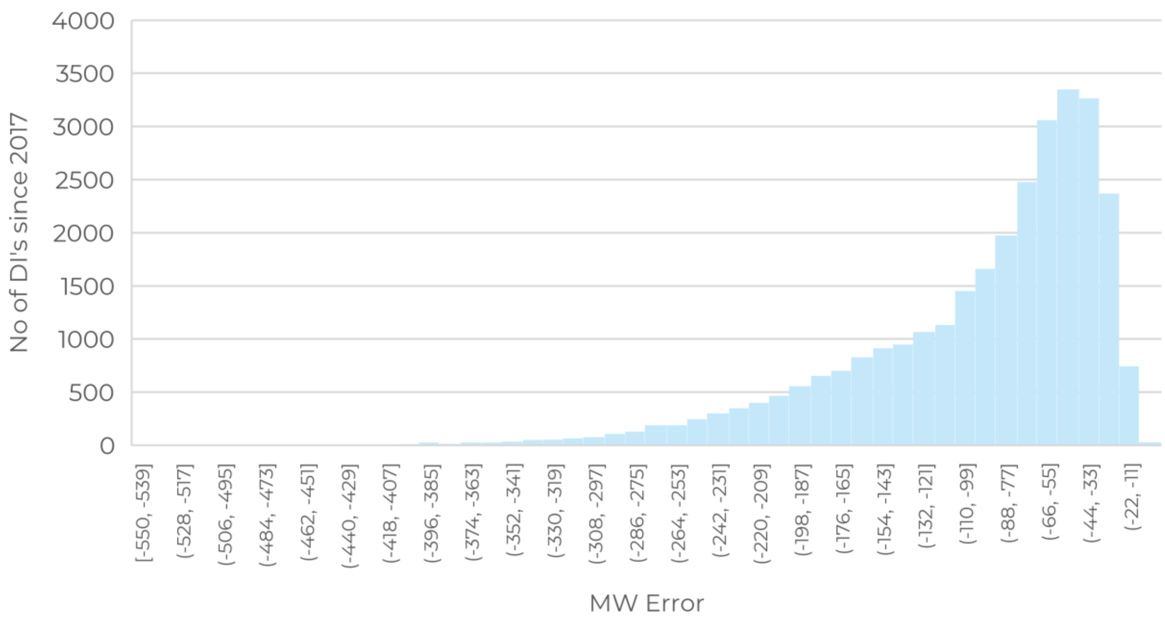


Figure 10 Dispatch Interval MW under forecast at Semi-Schedule Generators.



1.4 Summary of the problem statement

Infigen does not support rule changes that would require semi-scheduled generators to curtail output when generating above a forecast as there is no evidence that the current situation poses a system security risk.. Economically efficient frequency control and operating reserve frameworks are being addressed through existing AEMC and ESB processes.

Instead, Infigen supports evolution of existing rules to give the effect of prohibiting deliberate reductions in output, except in response to a signal from AEMO (including based on generator bids). This is discussed in greater detail below.

Infigen agrees with the AER that the most appropriate solution is a minor amendment to the existing rules regarding semi scheduled generation. However, we are opposed to other significantly disruptive and unnecessary proposed amendments. The objective of any selected method should be to ensure that semi scheduled generators are operating at the level their 'fuel' resource permits (subject to their bids). Requiring semi scheduled participants "*to follow dispatch targets in the form of a megawatt target, subject to the availability of the resource*" does not account for the adverse system impacts that this will have both on the LCOE of renewable generation, and also the additional requirements for ancillary services (Regulation FCAS and Primary Frequency Response).

2. Proposed approach

In summary, in our view the core problem identified by the AER that needs to be addressed is ensuring semi scheduled generators do not curtail output below their dispatch instructions unless instructed by an AEMO dispatch cap (either due to a constraint or through bidding) or limitations due to resource variability. We consider that this can be addressed through a relatively simple change to the semi-scheduled framework.

2.1 Nature of the change

The change should ensure that semi scheduled generators follow their forecast as the energy resource permits. Infigen proposes a relatively straightforward solution to amend the rules such that dispatch at a semi scheduled generator must be equal to the minimum of: a semi scheduled dispatch cap (when one is present); resource availability; or plant availability. This should also be subject to PFR/FCAS responses, plant/network protection systems, AEMO directions, etc. In particular, some care would need to be taken to ensure that semi-scheduled generators that (either voluntarily or through a mandated requirement) reduce output to help the frequency (i.e., deliver a governor-like response) are not penalised. The current Mandatory Primary Frequency Control framework provides examples of how this can be achieved. Similarly, a generator that manages its output to meet a linear trajectory should also be compliant.

This captures the intent of the semi-scheduled classification: providing a framework for resources that have less controllability over the underlying resource which is lost if not consumed. Effectively, this delivers the same benefits of the AER's proposals without imposing unnecessary limitations. It would allow for the natural correction of over and under generation to occur, reducing the requirement for Raise Regulation FCAS, and allowing generators to produce at the level of the available resource when not receiving a dispatch cap.

We do not expect this would be more difficult to implement than the AER's proposal – effectively, it is the "lower" half of the AER's requirement to meet dispatch targets, without the more onerous "raise" limitations. Under either proposal, there will still remain a regulatory obligation to justify the level of output from the available resource.

2.2 Certainty of reserves and frequency performance

We recognise that it is critical for the electricity system that sufficient resources are available to manage deviations. The existing market structures (Regulation FCAS, Contingency FCAS, and the intent to procure a sustainable level of tight-deadband Primary Frequency Control) provide AEMO the ability to procure sufficient resources to manage variability within a dispatch interval.

As has been observed recently, if frequency performance declines, AEMO is readily able to increase the quantity of Regulation FCAS procured. Semi-scheduled generators then have the ability to either "purchase" resources (through Causer Pays), reduce their demand for ancillary services by managing their output, or bid reserves into the ancillary service markets. (This would lead to AEMO-instructed curtailment, co-optimised with all other services).

2.3 Assessing compliance

As generators are required to operate within the National Electricity Rules, Infigen's proposed solution will be sufficient for ensuring semi-scheduled generators provide technically comprehensive offers without intentional deviation from forecast.

It would be reasonable to require semi-scheduled generators to keep appropriate records of resource and plant data to verify plant output deviations from their forecast.

The issue paper suggests that with a constraint to the maximum output, any dispatch below the AGC system instruction (while technically a breach of obligations for scheduled generators) to follow dispatch instructions could be through AWEFS/ASEFS values at the end of the interval.

We expect that assessing compliance under Infigen's proposed framework would be no more challenging than, for example, if the semi-scheduled classification were removed. In both cases, the AER would still need to identify whether underproduction was due to a resource limitation or a deliberate control/decision. At a high level, ultimate compliance should be determined through similar processes as used for managing 'good faith' provisions within the rules. Leading indicators however could be configured for either the AER or AEMO to monitor. These could include: comparing average deviations during negative and positive price periods; ensuring that the 'Control system set-point' Energy Conversion Model (ECM) SCADA tag reflects plant availability from bids and SCADA; and recalculating theoretical plant output based on wind speed or irradiance measures at the end of a Dispatch Interval.

We note that if wind and solar technologies were required to register as scheduled generators, the unit would not be compliant with their dispatch target for approximately half of all periods, due to resource availability below the target. This would also include variability around the linear ramp expected of scheduled generators. The existing AWEFS/ASEFS systems do not provide sufficient resolution to assess compliance at the end of dispatch interval. This would create a significant compliance burden on both market participants and the AER.

We also note that the treatment of hybrid facilities is complex. The value of using batteries for "self-firming" is also complex and needs to be considered by the AEMC in the context of a broader package on frequency control.

3. Conclusion

Infigen looks forward to continuing to engage with the AER on this issue. If you would like to discuss this submission, please contact Dr Joel Gilmore (Regulator Affairs Manager) on joel.gilmore@infigenenergy.com or 0411 267 044.

Yours sincerely

Ross Rolfe
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