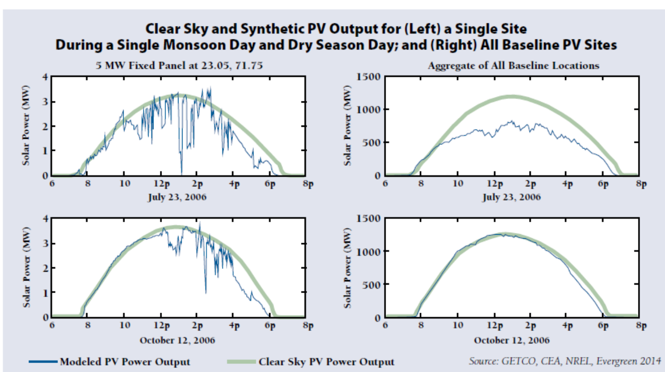
Comments on the proposed framework by CERC on Forecasting, Scheduling, and Imbalance Handling of Interstate RE Generators

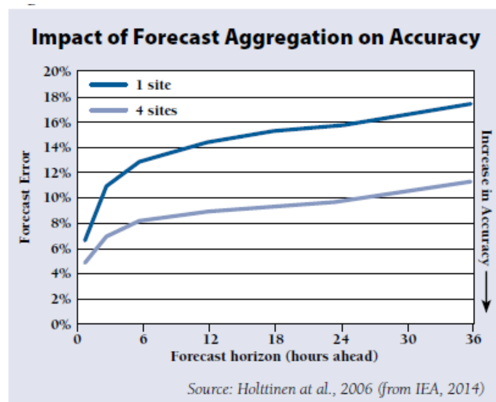
Note: Although these comments are in response to the proposed framework at the interstate level, they also apply to a potential such framework at the intrastate level.

1. <u>Importance of aggregation for forecasting, scheduling, and commercial arrangements</u>

RE integration costs and strategies depend on the variation and forecast of net load (load minus aggregate wind + solar generation). In a SLDC jurisdiction, conventional power plants within a balancing areacycle based on the aggregate net load and not on the variation in wind and solar generation from an individual site (assuming no intrastate transmission congestion).

In the proposed framework, if two RE generators deviate in the opposite direction with no net deviation from the aggregate schedule, both generators are expected to be penalized depending on the extent of their individual deviation even though they may not impose any additional costs on the overall system. The following figure shows that the aggregate variation (in percentage terms) over multiple sites is typically lower than the variation in output on one site; moreover, the forecasting accuracy is higher for aggregate forecast over multiple sites.





Source: NITI Aayog (2015). Report on India's Renewable Electricity Roadmap 2030.

Therefore, for scheduling purposes it is desirable to use the aggregate (total balancing area) level forecasts of RE generation; REMCs or any other agency in charge of forecasting/scheduling can use the site level data for arriving at the system level forecast.

2. <u>Ensuring best practice data and methods for aggregate level forecast</u>

RE integration costs depend on the accuracy of the RE forecast at the aggregate level; real-time generation data from individual RE generators can greatly improve the accuracy of the aggregate forecast. Therefore, RE generators should be required to share their real-time generation data with RLDC / SLDC irrespective of the commercial arrangement for forecasting / scheduling.

There is significant precedence in other regions of the world where wind and solar generators share such data routinely. The proposed framework states: "The wind/solar energy generator whose scheduling is done by the RLDCs, shall provide full data telemetry and communication facilities to the concerned RLDC." However, such data requirements should be proposed for all RE generators, and not just the ones that are being scheduled by the RLDCs. This is essential from a system security perspective. Same applies for the fault ride through requirements.

3. <u>Informing the deviations ranges specified by empirical analysis and international experience</u>

Deviation from scheduled generation, or rated available capacity?: Percentage deviation from scheduled generation will result in smaller deviation limits when the overall wind generation is low. These concerns were raised during the earlier RRF mechanism discussions. The impact on the overall system depends on the total aggregate MW deviation. An alternative is to specify a limit on MW deviation based on the rated available capacity in addition to the % deviation from schedule and havethe highest value of the two as the binding constraint. Deviation limits would also affect the smaller wind farms or developers disproportionately as compared to larger farms or developers, because larger farms have smaller aggregate deviations or errors.

Deviation limit of 12%: The proposed framework will benefit from a discussion on the rationale for the +/-12% deviation limit. A comparisonof forecasting errors experienced in India with those seen in other countries at individual wind farm levels and the overall aggregate level will better inform the deviation limits. Further, a fixed +/- 12% deviation limit could be replaced by a gradient rather than a single step limit. Such a deviation range should be related to international as well as Indian best practices, and actual measured data at the REMCs.

4. <u>Long run costs</u>

Putting the onus of scheduling on the individual RE generators (through their individual forecasts) would likely be much more expensive than the REMC scheduling all (or most generators) through an ensemble of forecasts and therefore, may increase the costs to the consumers in the long run. This is because, the forecast errors and the thus the amount of penalties would always be much higher if the scheduling is done at the individual RE generator level. Additionally, the transactional costs of generator level forecast would much higher than that of the aggregate system level forecast. Ultimately, these extra integration (penalties etc) or transactional costs would be passed on to the consumers either by RE generators (through an increase in the PPA price) or by the utilities (by buying more in the UI / short term spot market). Hence, it is important to find the most efficient solution for minimizing the overall costs.

Estimating the costs required to enable generators to forecast, schedule, and transfer real-time data to REMCs is essential to evaluate the various options. For example, it is necessary to assess how much additional cost would RE generators incur, especially if the older generators need to incorporate this cost ex-post their existing PPAs.

5. <u>Commercial incentives/disincentives for accurate forecasts within the proposed framework</u>

Given the variations in the feed-in tariffs and other commercial arrangement across the different states, RE generators may face different incentives or disincentives to provide accurate forecasts and schedules. Typically feed-in tariffs range from Rs. 3.5/kWh to Rs. 6/Wh.

Following are some examples where there may not be an incentive to forecast and schedule as close to actual generation as possible

Feed-in tariff ~ Rs. 3.5 (Tamil Nadu):

Wind generators may have an incentive to systematically under forecast and over inject. For example for 10% extra generation, wind developers will receive Rs. 5.5/kWh (Rs. 4 for energy and ~ Rs 1.5 for REC) instead of ~ Rs. 3.5/kWh, if they had an accurate forecast (such an incentive does not apply if does not if typical errors in the forecast is in the range of 12.5%)

Feed-in tariff is ~ Rs. 5 (Maharashtra):

Wind generators may have an incentive to systematically over-forecast and under-inject. For example for 10% less generation, wind developers will get Rs. 5/kWh and will have to pay Rs. 4.5/kWh for energy they do not generate (Rs. 3 for energy + Rs 1.5 for REC)

The core principle for providing incentive for accurate forecasting would be satisfied if the compensation received is highest when the forecast is most accurate.

6. <u>Alternatives to the proposed framework</u>

Given this background, the regulation could propose two alternatives:

a) Generators who provide real time data, expected outages and other data essential for forecasting to system operators (RLDC or SLDC) can get paid according to what they generate (not scheduled, but actual generation, based on their FiTs). This would act as an incentive for RE generators to provide real time data, that they will not be required to provide a schedule. These incentives are especially important to bring the intra-state RE generators on board. A variant of this option is that the individual RE generators can be assessed a deviation charge based on the aggregate (system level) deviation from the (system level) schedule. It is quite likely that forecasting will be more accurate at an aggregate level and hence the pooled charge will be lower; hence, wind generators may have an incentive to use this approach. Alternatively, wind generators who provide real time data should have an option to form a group whose deviation from the schedule is considered as an aggregate and who can decide how to allocate the pooled deviation charge among individual members.

b) Generators who do not provide real time data, (and those who are selling through Open Access) should provide a schedule. The financial arrangement proposed in this regulation could be applied to these generators for the short term. But in the long term, a real time market (or an hour ahead market) can enable these generators to make up for the day ahead forecast error, and ensure a total generation supply close to their original schedule.

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