UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Integration of Variable Energy Resources	)	Docket No. RM10-11-000

COMMENTS OF THE CALIFORNIA WIND ENERGY ASSOCIATION

On January 21, 2010, the Federal Energy Regulatory Commission ("FERC" or "Commission") issued a Notice of Inquiry ("NOI") seeking comments on the extent to which barriers exist that may impede the reliable and efficient integration of variable energy resources ("VERs") into the electric grid and whether reforms are necessary to eliminate those barriers.[1] The California Wind Energy Association ("CalWEA") hereby submits its comments in response to the NOI, which focus on the experiences of the California Independent System Operator Corporation ("CAISO") in implementing its Participating Intermittent Resource Program ("PIRP") and the benefits of providing centralized forecasting and scheduling practices for intermittent resources through a regional entity.[2]

I. BACKGROUND

In light of the rapidly increasing amount of VERs that are becoming a significant component of the nation's energy supply portfolio, the NOI seeks comments on the perceived barriers of integrating VERs (which include wind generation facilities) into the electric grid in a reliable and efficient manner. The Commission recognizes that integrating VERs presents unique challenges with respect to system reliability; however, with limited exceptions, its efforts

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1 *Integration of Variable Energy Resources*, Notice of Inquiry, FERC Stats. & Regs. ¶ 35,563 (2010).

2 We have reviewed the Comments of the American Wind Energy Association submitted in this proceeding and are in general agreement with those comments.

to remedy undue discrimination have not expressly accounted for the differences between VERs and more conventional generation resources. Thus, in order to meet the numerous challenges posed by integrating VERs while fully realizing their benefits, the Commission issued the NOI to explore whether existing rules, regulations, tariffs, or industry practices within the Commission's jurisdiction may hinder the reliable and efficient integration of VERs, resulting in rates that are unjust and unreasonable and/or terms of service that unduly discriminate against certain types of resources, and requests comments on how best to reform any such rules, regulations, tariffs, or industry practices.

The NOI enumerated a number of questions, with an invitation for the industry to respond, regarding existing operational practices and processes that affect the determination of the amount of reserves needed and the cost of those reserves. These questions sought comment on the impact of integrating VERs in the following subject areas: (1) data and reporting requirements, including the use of accurate forecasting tools; (2) scheduling practices, flexibility, and incentives for accurate scheduling of VERs; (3) forward market structure and reliability commitment processes; (4) balancing authority area coordination and/or consolidation; (5) suitability of reserve products and reforms necessary to encourage the efficient use of reserve products; (6) capacity market reforms; and, (7) redispatch and curtailment practices necessary to accommodate VERs in real time.

CalWEA is a non-profit corporation supported by over 20 members of the wind energy industry, including turbine manufacturers, project developers actively involved in developing wind projects for the market created by California's Renewable Portfolio Standards ("RPS") program, existing project owners, component manufacturers, support contractors, and others. CalWEA seeks to encourage and support the production of electricity through the use of

wind generators, and actively represents the interests of its members in various proceedings before regulatory agencies and the CAISO.

CalWEA believes that the CAISO's experiences in implementing the PIRP will assist the Commission in considering the questions raised in the NOI. Accordingly, CalWEA submits the following comments.

II. COMMENTS

CalWEA fully supports the Commission's goal of integrating VERs into the electric grid and submits that the California market is already well suited to allow participation by renewable power in the wholesale electric markets. California has made significant progress in promoting the integration of VERs into its supply portfolio and has continuing efforts underway to improve that integration. The Commission should, therefore, allow California's regional planning efforts to continue to be implemented within the California stakeholder process.

A. Scheduling Flexibility and Forecasting—Experience in California

The NOI recognizes that improvements in scheduling procedures may offer the potential for greater efficiency in dispatching all energy resources if variability can be reduced through better forecasting and scheduling. The Commission questioned whether the retention of existing transmission scheduling practices as additional VERs come on-line is causing rates for reserves to become unjust and unreasonable. The Commission has asked for comments on scheduling practices, flexibility, and incentives for accurate scheduling of VERs.

The CAISO's Commission-approved PIRP provides a compelling example of how enhanced data collection and centralized forecasting techniques can be used to manage

imbalances to allow VERs to be efficiently scheduled into the market.[3] The PIRP framework combines these elements to produce accurate schedules, prevent gaming and cost-shifting to others, and mitigate imbalance-energy risks for wind and solar generators. The PIRP has provided critical support for intermittent-resource development in California—no VERs were developed between the start-up of the CAISO in 1998 and PIRP implementation in 2003 except for two wind plants for which the California Department of Water Resources ("CDWR") agreed to assume the imbalance risk.

The PIRP requires VERs to meet the same output visibility requirements as other generators. This requires them to install CAISO-approved meters and telemetry that makes their output fully visible to the CAISO in real time. VERs must also provide real-time site-level meteorological data to the CAISO, through the same telemetering capability used for output measurement, that is gathered from required on-site meteorological stations (with independent power sources). These data include (i) wind speed and direction, (ii) solar irradiance (solar plants only), (iii) ambient temperature, and (iv) barometric pressure. In addition, VERs must report equipment outages affecting as little as 1 MW of output to the CAISO within 60 minutes (other generators are required to make these reports only for outages of 10 MW or more). The VERs are required to pay a small charge of $0.10/MWh to cover CAISO forecasting costs.

The CAISO has also developed a number of internal tools that enable it to better manage intermittent-resource variations on the system. These tools include incorporation of intermittent-resource forecasts into Day Ahead market and unit-commitment processes and 5-minute persistence models used for real-time market dispatch. A strong CAISO focus on meteorological and output data quality has yielded a number of program improvements over the

[3] *California Indep. Sys. Operator Corp*., 98 FERC ¶ 61,327, *order on compliance filing*, 99 FERC ¶ 61,309 (2002) (accepting the CAISO's tariff amendments implementing PIRP).

years. These improvements include, for example, validation checks and automated notices to plant Scheduling Coordinators when missing or anomalous data are detected (*e.g.*, significant wind speeds but zero output), as well as one-on-one contacts with individual plant operators to resolve data-quality issues.

To become a PIRP participant, VERs must sign a letter of intent and submit hour ahead plant-specific schedules of their output equal to forecasts provided by an independent forecasting vendor hired by the CAISO. The vendor uses the site-specific meteorological data, combined with data from other plants throughout the region and larger climate models, to produce an objective forecast based on past correlations of plant output and meteorological conditions.

VERs benefit from participating in the PIRP because they are not subject to 10-minute imbalance charges for deviations from forward schedules that are applicable to generators. PIRP generators are able to net their 10-minute deviations over each calendar month and pay net monthly imbalance charges calculated at the average locational marginal price at the plant location. PIRP participation mitigates the risk of sudden schedule changes in the output of VERs resulting, for example, from a sudden thunderstorm or a passing cloud.

CalWEA believes that PIRP has been an effective program to facilitate wind integration. The Commission should allow regions the flexibility to implement programs like PIRP with Commission oversight. To the extent the Commission believes that it is desirable to take a more prescriptive approach, CalWEA suggests that the Commission consider California's experience with PIRP in crafting any new generic requirements.

B. Specific Questions on Scheduling Flexibility

The Commission has asked for comments on whether shorter scheduling intervals would allow system operators to manage more efficiently the ramps of VERs and demand, and whether the availability of intra-hour scheduling would decrease the overall reliance on regulation reserves to manage the variability of VERs.

CalWEA believes that shorter scheduling intervals, for both intra-Balancing Authority Area ("BAA") and inter-BAA schedules, would greatly improve the efficient integration of large volumes of VERs while reducing the need to rely on resources used to cover imbalances from those schedules, perhaps including expensive regulating reserves.

Shorter interval intra-BAA scheduling, whether as part of a Real-Time Market model ("RTM") in an ISO/RTO structure or part of a Security Constrained Economic Dispatch model ("SCED") in the more traditional utility structures, allows the spread of the VERs' variability effectively across all of the BAA's generators that respond to regular dispatch signals. This is in contrast to the situation where longer (hourly) scheduling practices do not make use of the inherent flexibility of all the online generators during the hour and/or require the host BAA to cover all imbalances. Based essentially on the same mechanism, shorter inter-BAA scheduling, especially if combined with intra-BAA scheduling of equal or shorter duration, would allow the spread of the VERs' variability across all resources that respond to dispatch signals within a group of interconnected BAAs and better distribute imbalance responsibilities across both host and receiving BAAs.

In addition, shorter scheduling intervals allow BAAs' dispatch mechanisms (RTM or SCED) to use the most up-to-date VERs' output forecasts. This is critical for better

management of the uncertainty associated with VERs' output, as VERs' output forecasts become significantly more accurate as the time to the actual operating hour draws closer.

The Commission has asked what the benefits and costs would be of allowing resources and transactions to schedule on an intra-hour basis, and what tariff or technical barriers exist to implementing intra-hour scheduling. The Commission also asked whether there are best practices that could be implemented to facilitate greater intra-hour scheduling.

CalWEA believes that shorter scheduling intervals will address these issues by contributing to the better use of all system resources to meet power system flexibility needs. Although there are technical and operational complexities and costs associated with going to shorter scheduling intervals, these barriers are not insurmountable.

The Commission asked whether there is an optimum number of intervals within the hour for scheduling and what time increments would be necessary or desirable to achieve optimum flexibility while still meeting the relevant reliability requirements.

CalWEA submits that the higher the frequency of the intra-hour scheduling, the better the outcome from reliability, efficiency and flexibility standpoints. For a multitude of reasons, however, including diminishing returns in the face of the added complexity, technological limitations and costs, the shortest interval currently used in the industry for intra-BAA scheduling is now five minutes.

Depending on system characteristics, five-minute scheduling intervals, whether intra-BAA or inter-BAA, may not be required in all the North American Electric Reliability Corporation ("NERC") regions, though experience suggests that a reduction of the scheduling interval to 15 minutes, particularly for inter-BAA scheduling, could bring meaningful reliability, efficiency and flexibility benefits to the power system.

The Commission asked whether any reliability issues may result from changes to the scheduling rules and what changes might be needed to NERC reliability standards.

Balancing areas that schedule energy transactions on an hourly basis must have sufficient balancing resources (including regulation resources) to manage the intra-hour system variability needs, including the added variability due to VERs, in order to maintain the schedule fixed for the hour and meet the NERC Control Performance Standard 2 ("CPS2") requirement. The CPS2 standard requires BAAs to be in balance in at least 90% of the 10-minute periods each month. Since this is a 10-minute measure of reliability, shortening scheduling periods to 15 minutes would lessen the impact of VERs on CPS2, and thereby lower the balancing and regulating reserve requirements of VERs.

The Commission has also asked how intra-hour scheduling would affect other processes such as available transfer capability ("ATC"), the E-Tag system, issuance of dispatch instructions for generation or demand resources, transmission loading relief procedures ("TLR"), and dynamic schedules, and what the costs might be.

Intra-hour scheduling will lead to more frequent ATC updates. There are benefits in having more granular ATC data and the added computational and information posting requirements should not be too onerous. The same assessment would also apply to the E-tag systems as well as to the systems and processes used to issue dispatch instructions for generation and/or demand resources, transmission loading relief procedures, and/or dynamic schedules.

The availability of more granular ATC and E-tag information will improve the accuracy of the inter-BAA scheduling process, leading to better use of resources across multiple BAs to deal with VERs' variability. As noted earlier, this will reduce reliance on balancing needs (including regulating resources) to deal with VERs variability and will reduce the costs of

these resources, or make them available to the system operator to meet other needs. In either case, this would improve system efficiency.

With respect to intra-hour scheduling in non-RTO/ISO regions, the Commission asked how RTO/ISO scheduling practices at interties would be affected and what problems might arise.

CalWEA believes that intra-hour intertie scheduling between traditional utilities and RTOs or ISOs will allow more up-to-date and accurate interchange data to be used in the real-time scheduling process of the RTO/ISO. This will allow the RTO/ISO to better manage system efficiency and reliability through the use of interchange with neighboring BAAs. The same principle applies to traditional utilities using the SCED model. The main concern with intra-hour scheduling would be related to technology challenges of implementing more frequent scheduling, which should be readily manageable.

C. Specific Questions on Data and Forecasting

The Commission has asked a number of specific questions on data and forecasting requirements. CalWEA believes the PIRP approach, described above, provides a sound framework to address many of the issues the Commission has raised. For example, the Commission has asked what the current practices are to forecast generation from VERs and whether those practices will be adequate if the number of VERs increases. Centralized data collection, forecasting and scheduling through the CAISO, coupled with monthly netting, have allowed California to effectively and efficiently integrate a large and growing number of wind resources, as noted above.

Moreover, the VERs output forecasting systems and tools are being significantly improved to address the increases in the volume and technological and geographic diversity of

VERs. Furthermore, centrally managed VERs output forecasting systems are being integrated into operation of the grid to ensure that system operators and the ISO/RTO and traditional utility participants can create efficient and secure operating plans using all necessary resources, including demand side resources. These systems are being significantly improved to minimize forecast errors, especially as the operating hour draws closer. Forecasting systems can also generate accurate forecasts for each delivery node in the transmission system, which is crucial for operation of many of the modern transmission constrained unit commitment models (*e.g.*, Day Ahead Market (DAM) and Hour(s) Ahead Market (HAM), and transmission constrained system dispatch model, *e.g.*, RTM).

The Commission also asked what is necessary to transition from the existing power generation forecasting systems for wind and solar generation resources to a state-of-the-art forecasting system.

CalWEA believes that VERs owners are willing, with proper safeguards, to provide all the data that the system operator needs for its accurate forecasting applications, especially if the system operator can show that it can effectively use such data to better manage system operation in the presence of large volumes of VERs. We believe that the key near real-time data required by the system operators include wind speed and direction, barometric pressure, temperature, turbine availability, and breaker status. In addition, we believe that system operators need to know about maintenance schedules and forced outages or derates for VERs plants. Additionally, automated or manual processes to translate certain weather patterns, such as knowledge of incoming thunderstorms, can help supplement automated VERs output forecasting systems.

The Commission has asked what data, forecasting tools and processes system

operators need to more effectively address ramping events and other variations in VERs output, and to validate enhanced forecasting tools and procedures.

Large VERs' output ramps, particularly those that are not repetitive and readily predictable, are a big concern to most system operators. However, such unpredictable large ramps typically stem from highly localized events, such as thunderstorms, that usually affect only a small percentage of the VERs at a given time. This means that in larger systems with large and geographically and technologically diverse VERs, such localized events will not have a big reliability impact. It should also be noted that the industry is becoming more familiar with the many climatic sources of large ramps such as thunderstorms, mountain wave events, cold frontal passage, and flow channeling, and working to incorporate the impact of these events in VERs output forecasting systems and processes.

D. Capacity Markets, Day-Ahead Markets, Capacity Commitment & Real-time Adjustments.

1. Capacity Markets.

The Commission seeks comments on whether capacity rating rules as applied to VERs are unduly discriminatory and whether obligations for capacity resources to offer into the day-ahead market unfairly discriminate against VERs. As discussed above, in general, California's PIRP approach relies on centralized data collection, forecasting and scheduling to manage the imbalances associated with VERs, thereby increasing their ability to make capacity available to the market.

The Commission asked a series of questions about how the rules for capacity resource participation in regional markets impact VERs. For example, the Commission asked if it should examine whether capacity rating rules as applied to VERs are unduly discriminatory and investigate whether standard rules may be appropriate. It wanted to know if the obligations

for capacity resources to offer into the day-ahead market unfairly discriminate against VERs, and whether they will be adequately compensated for providing reliability services. For instance, should the Commission examine formation of forward ancillary services capacity markets? The Commission also asked if capacity markets should incorporate a goal of ensuring sufficient generation flexibility to accommodate ramping events in addition to the goal of ensuring sufficient generation to meet peak demand.

Unfortunately, when it comes to determining the capacity value of VERs, some regions of the country, including California and SPP, still rely on the notion that capacity is of value only during a few hours in a year during the annual system peak. This deterministic approach originally came about as traditional utilities tried to simplify the analysis of power system reliability from a complex and probabilistic process into a simple deterministic process that they could manage using the limited tools that they had at their disposal. Some of these regions (*e.g.*, California) have tried to add "probabilistic flavor" to this deterministic concept by using unscientific methods such as the ad hoc "exceedance" approach.

Other regions, such as the Electric Reliability Council of Texas ("ERCOT"), have realized that a generator's capacity actually reflects the capability of that generator to meet an extra amount of load during all high-risk time periods. The NERC Task Force for Integration of Variable Generation ("IVGTF") has also recognized this concept and proposes that a well established analysis method called the Effective Load Carrying Capability, or "ELCC," be used to determine a VER's capacity value:

> The ELCC approach considers all hours in a given planning period (typically a year) and the contribution of the variable generation output to capacity requirements during all time intervals of that period. ELCC calculations are typically conducted through reliability simulations that consider conventional generating outage and maintenance characteristics and the hourly annual demand shape. In order to appropriately consider the capacity contribution of variable

> generation, the output of the variable generation should be represented by hourly primary fuel (e.g. wind or solar) data and characteristics of the generator. Care should be taken to account for the correlation between hourly variable generation and the hourly demand series. To perform this analysis, a significant amount of time-synchronized 8,760 hourly wind generation and demand data is required and this data is needed for variable generation plants in the specific geographic regions being studied.[4]

We believe that the capacity value of all resources and especially that of the VERs should be calculated using the ELCC method.

When it comes to determining the Resource Adequacy capacity credit of a VER for a particular month of the year, the ELCC analysis may be conducted based on that VER's performance during that month. A VER should be allowed to participate in all capacity markets of a month (whether monthly, daily, or hourly) based on its ELCC determined capacity value of the VER for that month. The annual VER capacity value, again calculated using the ELCC method, may be used for participating in the annual capacity markets.

2. Day-Ahead Market Participation

The Commission seeks comments on whether VERs should be allowed to participate in the day-ahead market and whether such integration would create operational or market transparency problems. Among the questions the Commission asked is whether current RTO/ISO market designs place undue barriers to participation in forward markets by VERs, and whether the timing of certain RTO/ISO market design elements, such as the day-ahead market, can be modified in a manner that would allow VERs to participate more in the day ahead market rather than primarily in the real time market. In addition, the Commission asked:

Would the use of more accurate forecasting tools facilitate participation of VERs in the day-ahead market rather than primarily in the real time market? If so, how?

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[4] North American Elec. Reliability Corp., *Special Report: Accommodating High Levels of Variable Generation* 38 (Apr. 2009).

Should the financial risk of VERs' participating in the day-ahead market be different than the risk imposed on other resources in that market in recognition of their unique characteristics? Are there settlement practices, such as netting deviations, which could be employed to address VERs' participating in the day-ahead market? If so, what are they?

Will changes to the financial risk of participating in the day-ahead market encourage VERs to participate in day-ahead markets, and will this participation result in day-ahead market schedules that accurately reflect real-time market activity?

It is appropriate to distinguish between the need for individual VERs to schedule in the Day Ahead market and the desirability of having BAAs consider likely real-time VERs output in Day Ahead scheduling and unit commitment. The former may not be as necessary if the BAA's capability to do the latter is improved.

The main barrier to Day Ahead scheduling of VERs is the tremendous potential exposure to charges for imbalances from those schedules. For that reason, PIRP participants in the CAISO are exempt from the Day Ahead Must-Offer Obligation applicable to Resource Adequacy (RA) Resources.

However, the CAISO is planning a new initiative, to begin later this year, that would (among other things) examine ways to encourage Day Ahead scheduling by intermittent resources. That initiative could consider extending the monthly netting approach now applied to imbalances from Hour Ahead PIRP schedules to the Day Ahead timeframe.

As noted above, however, even without individual Day Ahead schedules, improved BAA DA forecasting ability can allow expected VERs output to be considered in the Day Ahead market and unit-commitment process. This capability lowers costs to VERs and

ratepayers, and enhances reliability, by ensuring that the right amount of non-VERs resources are committed in that scheduling timeframe.

3. Reliability Commitment Processes

The Commission seeks comments on reliability commitment processes and whether they can reduce the amount of reserves needed and/or reduce system uplift costs. It asks whether the implementation of a formalized and transparent intra-day reliability assessment and commitment process prior to each operating hour would reduce the amount of reserves needed and/or reduce system uplift costs. The Commission also asked if an additional market that coincides with the timing of an intra-day reliability commitment process would be beneficial in the forward scheduling of VERs. Finally, the Commission asked what role centralized forecasting of VERs' output should play in the reliability assessment and commitment processes.

Intra-day commitment is becoming a standard feature of the organized markets due to its allowance to use the most up-to-date, hence more accurate, system information to more efficiently and reliably commit system resources. CalWEA believes that California's experience with PIRP, and with VERs generally, is instructive in responding to many of the Commission's questions.

As discussed above, centralized data collection, forecasting and scheduling of VERs resources plays a critical role in the participation of these resources in California's markets while allowing for the effective management of energy imbalances, by allowing accurate commitment of non-VERs resources. Because VER forecast accuracy increases significantly the closer to real time the forecast is developed, combining these centralized practices with hourly reliability assessment and commitment would likely lead to further benefits through reduced need for excessive unit commitment and balancing-resource dispatch (including regulating reserves to manage intra-hour fluctuations). An additional market that coincides with the timing

of an intra-day commitment would be beneficial to the outcome of the commitment process with or without VERs, as it allows the reliability commitment process to use the most up to date market information. Due to increased accuracy of VERs output forecasts through practices such as those implemented through PIRP, intra-day markets would enhance the ability of VERs to participate.

4. Real-Time Adjustments

The Commission seeks comments on whether redispatch and curtailment practices have changed with increased numbers of VERs and whether these practices unduly discriminate against VERs.

Unfortunately, the curtailment of VERs, and particularly wind resources, is becoming too commonplace in places where such resources are gaining in volume. Such "curtailment" can consist not only of direct curtailment orders but also restrictions on ramping and other operational rules.

While we understand that VER curtailment could be used as an effective measure to address power system reliability needs, we are concerned that at times VERs curtailments are being used simply because of the procedural ease of using such curtailments, *e.g.*, (1) where such issues could be better addressed through other grid-level tools, like transmission investments or voltage-support markets; and/or (2) such restrictions may be used to address system problems that have nothing to do with VERs operation. We would like the system operators to consider all economic (market based) and customary measures available to them in dealing with situations where generation should be reduced to deal with transmission congestion or over generation conditions. Such measures could include:

- Imposing needed operating restrictions on all generators equally, and not just on VERs;

- Reduction of conventional generation resources to their minimum allowed sustained output;
- Ensuring that minimum generation levels known to system operators for conventional generators is up-to-date;
- Ensuring that imports to the BAA is at minimum allowed levels;
- Ensuring that all energy export possibilities from the BAA are taken into consideration;
- Ensuring that the minimum must-take generation, if applicable, are properly accounted for;
- Grid-level investments that could minimize the need for such actions;
- Additional market mechanism, *e.g.*, economic bids from VER and non-VER resources and markets for Regulation, voltage support, and other needed services; and
- Ensuring that other must-run resources such as hydro generation are sharing the curtailment along with VERs – there should not be any built-in assumption that wind and insolation should be "spilled" ahead of water, i.e., minimum generation here should reflect only other factors like physical capabilities, environmental requirements, etc.

The Commission has asked in the NOI if existing redispatch and curtailment processes unduly discriminate against VERs, and how such processes should be modified.

As we noted in our response to the previous question, we believe that VERs' curtailment does take place in situations where other effective measures to manage system-wide or localized over-generation condition exist, and that such measures are often applied discriminatorily to only VERs. We believe that the combination of measures, tools and practices that we discussed earlier, and careful use of all effective measures to reduce generation, would go a long way in reducing unnecessary curtailment of VERs.

The Commission could also consider requiring system operators to allow VERs and other resources to provide "curtailment bids" to be used by the system operator to make rational decision regarding curtailment priority of all the resources that are available to it. The

allowed curtailment bid levels should be allowed to be set at a level that would reflect the revenue loss due to PPA contractual payment, PTC payment losses, and (for non-VERs) any other related costs, like take-or-pay gas contracts.

The Commission asked if transmission loading relief protocols should be altered to allow reliability coordinators in non-RTO/ISO regions to consider economic merit when considering curtailing VERs. Similarly, the Commission wanted to know if redispatch and curtailment protocols in non-RTOs/ISOs should be revised to consider economic merit for all resources and, if so, how.

As we note elsewhere in our comments, the entire contract path transmission reservation practices outside RTO/ISO footprints should be fundamentally re-examined in order to improve the economic and reliability of the power system even without the consideration of the VERs integration issue. For example, current rules that explicitly or implicitly require Day Ahead schedules to obtain firm intertie capacity should be revised to accommodate the intermittent nature of VERs. We believe such re-examination and potential over-haul will also aid with better VERs integration.

The Commission asks to what extent VERs can respond to specific dispatch instructions, and whether there are any advanced technologies that could be adopted by VERs to control output to match system needs more effectively.

Subject to the availability of their primary fuel, practically all modern VERs plants are capable of responding to the system operator's dispatch signal. As we noted earlier, the main concern here is not the capability to respond to dispatch signals but to ensure that the dispatch signal itself is issued by the system operator considering all the underlying economic

and reliability considerations and that the VERs, like other generators in the system, are allowed to recover their opportunity costs for responding to the dispatch signal.

E. Balancing Authority Coordination

In the NOI, the Commission notes that smaller balancing authorities may be unable to capture the benefits associated with VERs that are spread across a large and/or diverse geographical area. The Commission asked for comments on whether increased coordination among balancing authorities has the potential to enlarge the base of generation and demand available to customers, and whether it should encourage the consolidation of BAs.

Smaller BAAs are typically expected to have higher VERs integration costs due to limited access to sources of system flexibility to help manage VERs variability – similar to their higher reserve needs generally. On the other hand, larger BAAs (geographically and electrically) offer two major benefits when integrating large volumes of VERs. First, they typically have access to more flexible resources that help manage VERs variability. Second, they typically allow for VERs on a wider geographic footprint to interconnect to the BAA grid. The wider the geographic footprint of VERs, generally speaking, the less variability in the overall output of all BAA VERs resources.

In the face of numerous economic and reliability benefits of larger BAAs, which go far beyond facilitation of VERs integration, we strongly urge the Commission to encourage better coordination of BAAs, including formal consolidation, as well as reserve-sharing, dynamic scheduling, and other flexible arrangements that would lower integration costs overall. In that regard, we believe that this can be accomplished through better coordination and sharing of system flexibility resources across BAA boundaries.

We consider most barriers against BAA coordination to be mostly artificial in nature and stemming from the unfounded concerns of the transmission owners about loss of

control, or from lack of available transmission capacity among BAAs. It must, however, be noted that the lack of transmission capacity between BAAs in itself is mostly due to arcane contract path transmission reservation rights that the traditional utility structures still follow. All these barriers can be overcome with some rethinking of the processes that are used to manage system resources and to determine and manage the availability of transmission capacity among BAAs.

We encourage the Commission to require various regions of the country to propose plans for physical or functional consolidation/coordination of BAAs within their region and clearly articulate all reasons and impediment that they have against such consolidation.

The Commission also asks what tools or arrangements—such as dynamic schedules, pseudo-ties, and virtual balancing authorities—are available or could be enhanced or created to reduce barriers to greater operational coordination among balancing authorities?

A number of tools and measures, including those mentioned by the Commission, are currently available to the industry and should be used as much as possible to implement some level of functional BAA coordination. Other similar tools and measures that should be considered for this purpose include sub-hourly inter-BAA scheduling, Area Control Errors (ACE) pooling across multiple BAAs, and region-wide load following and ancillary services markets.

The Commission asks in the NOI what the costs and benefits would be of the proliferation of small generation-only balancing authorities?

CalWEA believes that consolidated BAAs (physical or functional) should obviate the need for generation-only balancing authorities. Generation-only balancing authorities should be considered as a measure of last resort in cases where existing BAAs raise significant barriers

to VERs integration. The sub-optimal generation-only BAAs do not have the needed generation or load resource flexibilities for efficient system operation. Furthermore, the administrative cost of operating a BAA, including the cost of running various regulatory compliance requirements, can be prohibitively expensive.

F. Reserve Products and Ancillary Services

The Commission asks a number of questions in the NOI about the ability or obligation of VERs to provide ancillary services, and how the reforms proposed in the NOI may mitigate the need for additional reforms to existing reserve products. The Commission also asks whether it should change the definition of a contingency event triggering the use of contingency reserves to include extreme VERs ramping events, and whether it should develop a new category of contingency reserves. Finally, the Commission asks to what extent VERs should be required to provide frequency response service to the transmission provider.

CalWEA believes that the effective tools, measures and procedures that we have discussed elsewhere in our NOI response will go a long way in mitigating the variability and the recurrent ramp events associated with VERs, and help to manage the remaining variability by mainly relying on a variety of system resources that typically respond to dispatch signals across a wide electrical areas as opposed to relying on system reserves. As a result, much of system reserves would be freed up to deal with system contingencies including extreme, but rare, VERs ramping events.

We believe that extreme VERs ramping events can be managed by a combination of spinning and non-spinning reserves. We also believe that the majority of the reserves needed to address extreme VERs ramping events will be non-spinning reserves. The determination of the exact amount of spinning and non-spinning reserves needed to manage extreme VERs

ramping events would depend on a number of factors, including the probability and size of extreme VERs ramping events and the volume of VERs in the system.

With respect to contingency reserves, we believe that the idea of a new source of reserves for managing VERs extreme ramping events has resulted from the misconception that existing system reserves are needed to manage typical VERs output variability and recurrent VERs ramp conditions. Hence, we believe that existing system contingency reserves (spinning and non-spinning reserves) can be used to deal with extreme VERs ramp conditions, and there is no need to define a new reserve product. However, VERs should be allowed to participate in any reserves market for which they can physically provide the service, with adequate compensation from the market.

Finally, we recommend that the Commission adhere to its current policy in Order No. 661 to exempt wind resources from the obligation to supply frequency response service to the transmission provider, absent a case-specific demonstration of need, a showing that the benefits outweigh the costs, and explicit recognition that VERs supplying this service will be permitted to recover their fully-loaded cost for doing so from the transmission provider. In this regard, in Order No. 661 the Commission required wind generation facilities to maintain the required power factor range only if the transmission provider shows through a system impact study that such capability is required from that facility to ensure safety or reliability.[5] The Commission's approach in Order No. 661 was to balance the benefits and burdens of requiring VERs to provide reactive power support, and it recently reiterated that in evaluating this question

[5] *Interconnection for Wind Energy*, Order No. 661, FERC Stats. & Regs. ¶ 31,186, at PP 50-52, *order on reh'g*, Order No. 661-A, FERC Stats. & Regs. ¶ 31,198 (2005). This approach does not currently apply to non-wind VERs, *id*. at P 106, and the Commission recently decided to defer consideration of whether to apply the Order No. 661 approach to those VERs. *Nevada Power Co.*, 130 FERC ¶ 61,147, at P 24 (2010).

"we must consider the burden on [the] specific generator to provide reactive power support and the probability that the reactive power support provided by the generator will be critical to maintaining the safety and reliability of [the transmission provider's] system."[6]

Thus, given that reactive power must ordinarily be provided in a local area, the question of reactive power support invariably must be decided on a case-by-case basis. Since the issue is one of maintaining the safety and reliability of the transmission system, the burden of demonstrating that VERs need to provide reactive power support should fall on the transmission provider. Absent compelling evidence of need, the Commission should continue to apply the presumption that VERs need not supply reactive power as a condition of interconnecting to the transmission system. The Commission should permit VERs to rebut any such evidentiary showing of need by presenting evidence that their facilities are not inherently capable of providing reactive power support without additional equipment and expense. If the Commission ultimately determines that VERs must procure the necessary equipment and provide the service, the Commission should make clear that they will be permitted to recover the cost of such equipment from the transmission provider through an appropriate reactive power charge filed with the Commission.

[6] *Nevada Power*, 130 FERC ¶ 61,147, at P 25.

III. CONCLUSION

WHEREFORE, CalWEA respectfully requests that the Commission consider the comments submitted herein.

Respectfully submitted,

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April 12, 2010