UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

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

COMMENTS OF THE BONNEVILLE POWER ADMINISTRATION

On January 21, 2010, the Federal Energy Regulatory Commission (the "Commission") issued a Notice of Inquiry ("Notice"), seeking comment on the extent to which barriers may exist that impede the reliable and efficient integration of variable energy resources ("VERs") into the electric grid, and whether reforms are needed to eliminate those barriers. The Bonneville Power Administration ("BPA") appreciates the Commission's thoughtful and detailed focus on these important and timely issues affecting the future of the nation's electricity industry. BPA submits the following comments in response to the Notice.

BPA is a Federal power marketing administration established to market wholesale electric power from the Federal hydroelectric projects in the Pacific Northwest. BPA currently markets power from 31 Federal hydro projects and some non-Federal projects and operates over 15,000 miles, or approximately 80%, of high-voltage transmission lines in the region. BPA provides transmission on an open-access basis. BPA's service territory covers Washington, Oregon, Idaho, western Montana, and portions of California, Nevada, Utah and Wyoming. BPA's wholesale power customers include public utilities, public utility districts, municipal districts, public cooperatives, investor-owned utilities, and a few large industrial customers.

As of 2010, BPA has approximately 2,800 MW of wind facilities on its system. Most of those facilities are located in a relatively small area near the Columbia River Gorge. With a peak balancing authority load of 10,500 MW and a minimum light load of 4,000 MW, the wind penetration in the BPA balancing authority is among the highest in the nation.

Primary Messages for the Commission Notice on Variable Energy Resources

BPA supports the reliable and cost-effective integration of VERs. As the Commission recognizes, rapid development of VERs raises issues regarding reliability, cost allocation, and the roles and responsibilities of balancing authorities. The need to clearly define balancing authority roles and responsibilities is especially important to BPA, because approximately 80 percent of the almost 2,800 MW of wind generation currently on BPA's system is exported to other balancing authorities, and BPA's preference customers should not bear costs of integrating wind generation that is exported to serve load outside of BPA's balancing authority. The challenges and cost allocation issues associated with the management and export of significant amounts of wind generation from BPA's balancing authority strongly influence BPA's comments in response to the Notice. Although increased balancing authority coordination and changes in market design may address some of these issues over time, BPA's comments are based on the markets and structures currently in place in the Pacific Northwest.

BPA's comments address issues substantially more important than just BPA's parochial interests. As VERs are increasingly developed in locations that are remote from load centers, one of the keys to successful large-scale expansion will be establishment of policies, regulations, and cost-recovery mechanisms that ensure that exporting balancing authorities are not exposed to additional costs or reliability risks. If host regions for VERs experience reliability risk or increased costs for resources that are being exported, it will become increasingly difficult to build new projects in those regions, potentially limiting access to cost-effective resources. Although no single reform will address all issues, a combination of clarifying balancing authority responsibilities with respect to providing the capacity reserves necessary for VER balancing, promoting targeted improvements in VER forecasting and scheduling accuracy, and increased balancing authority coordination will help facilitate the integration of VERs in a manner that does not create cost shifts or increased reliability risk. With these points in mind, the following list summarizes the primary messages in BPA's comments in response to the Notice:

1. Cost Allocation

Currently, it is possible to interpret Schedule 9 of the Commission's *pro forma* tariff to mean that balancing authorities in which VERs are physically interconnected have the default responsibility to provide balancing reserve capacity necessary to maintain reliability when VER ramps (up or down) result in output that deviates from scheduled levels *even if such output is exported to serve load in other balancing authorities.* Current policies are leading to duplicative and inefficient carrying of reserves by both source and sink balancing authorities as well as creating cost and reliability risks for host balancing authorities from which VERs are being exported. The Commission should reevaluate the roles and responsibilities of source and sink balancing authorities. Source balancing authorities should not be required to act as default suppliers of balancing reserves for VER exports, but rather should be allowed to clearly define and enforce limits to their balancing reserve obligations.

Rather than serving as default suppliers, source balancing authorities should strive to facilitate options for VER exporters to acquire balancing reserve capacity from alternative sources. Such options could include scheduling and operational tools such as self-provision of balancing reserve capacity or intra-hour scheduling and dynamic transfers to the extent that these options do not adversely impact system reliability and the value of these options does not exceed the cost of making them available.

The owners and operators of VERs should develop balancing plans that clarify the VERs' preferred source(s) for procuring balancing reserve capacity. These balancing plans should be submitted to source balancing authorities during the interconnection process and on a regular basis thereafter.

If, after considering other options, the VER submits a balancing plan indicating that it still prefers to procure some or all of its balancing capacity from the source balancing authority, the source balancing authority can enter into a commercial transaction for such balancing capacity with full cost recovery and risk protections for its preference or native load customers. The obligations of the source (exporting) balancing authority should be limited to the quantity of capacity for which it has contracted with the VER. If the VER's chosen portfolio of balancing capacity (including purchases from the source balancing authority) is insufficient to manage the balancing needs of the VER, it is the VER operator or buyer and the sink balancing authority that should be accountable for making up any balancing shortfalls. This distinction between being a default supplier as opposed to a fully compensated party to a clearly defined and delimited commercial transaction is essential to the sustainable growth of VERs in exporting regions.

Balancing authorities with substantial amounts of VERs relative to their available balancing reserves likely will require operational and reliability protocols to enforce generation reductions or schedule curtailments when VERs cumulatively operate substantially outside of schedule and available balancing reserve capacity is close to being exhausted. A source balancing authority can use such protocols to preserve the reliability of its system and limit its provision of balancing reserve capacity to its contractually defined obligations. In collaboration with VER sellers and purchasers, balancing authorities can use such protocols to help achieve a balance between quality of service and cost (*e.g.*, carrying a smaller quantity of balancing reserves reduces costs but increases the likelihood of generation reductions or schedule curtailments and *vice versa*). This balance can be defined by the VER operator and purchaser based on their willingness to pay for maintaining reserves. Over time, emerging mechanisms such as intra-hour scheduling may mitigate the impacts of schedule curtailments on receiving balancing authorities and allow for more efficient and economical provision of balancing reserve capacity.

As increasing amounts of VERs locate within a source balancing authority and export output to a sink balancing authority, the VER balancing reserve capacity requirements may ultimately exceed the capability of the source balancing authority's available generating resources. If this occurs, the source balancing authority should have the ability to acquire additional balancing reserve capacity in a cost-effective manner and allocate the incremental costs and stranded cost risks to the class of customers driving the need for the additional balancing services.

If buyers and sellers of VER generation have adequate choices for providers of balancing reserve capacity, it may be possible and appropriate for source balancing authorities, which have historically provided such capacity at embedded cost rates, to be given the discretion to charge incremental or market-based rates for the use of their balancing reserve capacity. This may be a way to encourage the development of cost-effective balancing reserve capacity resources and new markets as well as preventing the hyper-concentration of VER variability on individual systems.

2. Forecasting

Investments in VER forecasting can provide substantial value. Forecast uncertainty and inaccurate scheduling are among the largest contributors to balancing reserve capacity requirements for VERs. Improvements in forecasting and scheduling accuracy can reduce the amount of balancing reserve capacity that balancing authorities will need to carry to balance VERs, which will help reduce integration costs. Data collection can be improved through collaboration with the National Weather Service. Sharing of meteorological data should be strongly encouraged but not mandated.

A few years ago, BPA eliminated the penalty band of its generation imbalance rate in order to encourage wind power development. With the rapid increase of wind on BPA's system and the well-documented importance of scheduling accuracy, BPA believes it may have gone too far. As a result, BPA has reinstated penalties for extended (*i.e.*, four hour) deviations from scheduling accuracy in the same direction. BPA is not certain that it has found exactly the right solution but believes it is necessary to send price signals regarding the cost of scheduling inaccuracy where it potentially is within the control of the VER to improve. The party that can best improve scheduling accuracy should receive the price signal. VERs or the loads served by VERs must bear the energy and capacity costs associated with inaccurate schedules. However, even with state-of-the art forecasting, balancing authorities will still need mechanisms to manage "tail events" (*e.g.,* infrequent, but very large unscheduled ramps of VER output).

3. Intra-Hour Scheduling

Intra-hour scheduling has the potential to help better manage the costs and operational impacts of VER generation imbalances. Several transmission providers in the Pacific Northwest are already working together to accelerate the development of intra-hour scheduling, including the adoption of common business practices, dynamic transfers and an intra-hour bulletin board to facilitate within-hour transactions. Given these collaborative and ongoing efforts, the Commission should encourage but not mandate intra-hour scheduling and allow regional cost-benefit analysis.

4. Balancing Authority Coordination

Increased balancing authority coordination is under consideration in a variety of forums across the Western United States. Given the rapid increase in VERs in the Northwest over the past five years, there is potentially much greater value in balancing authority coordination than there was during previous attempts to address market design in the region. This is particularly the case with respect to the potential benefits of working across existing balancing authorities to address within hour variability. That said, additional changes to market design involving the creation of independent entities or Regional Transmission Organizations ("RTOs") should be evaluated against the benefits of fully implemented bilateral mechanisms such as the ColumbiaGrid, Northern Tier Transmission Grid, and WestConnect Joint Initiative. The Commission should encourage, but not mandate, the virtual or physical consolidation of balancing authorities while relying on regions throughout the country to determine institutional structures that create the most value.

5. Market Impacts of VERs

VERs that have little demonstrable capacity value should only be allowed to participate in day-ahead markets to the extent that they can support their uncertain and variable generation with other dispatchable capacity resources or products. The Commission should not institute measures that relieve some parties in a commodity market of financial risk at the expense of other market participants. To the extent that risk is different for different products, that risk should be transparent and should be reflected in the value that the market assigns to that product.

Negative market prices are raising concerns about VER production at times when market signals tend to incent traditional generators to reduce generation output or shut down, such as during light load hours or fish-related spill conditions in a hydro-based system. During times when a balancing authority is operating to meet other mandatory non-power constraints such as flood control or Endangered Species Act requirements, continued operation of the VERs can increase risks to system operations and violations of other mandates. BPA believes that balancing authorities should not be obligated to pay VERs to reduce generation output when necessary to meet statutory, environmental, or reliability obligations.

6. Voltage and Reactive Power Requirements

BPA supports the North American Electric Reliability Corporation's ("NERC's") recommendation to develop consistent interconnection standards to ensure low-voltage ride-through, reactive/real power control, and frequency and inertial response requirements for all generation technologies.

BPA'S COMMENTS

BPA's comments are organized into three main sections. Section I provides background regarding the integration of VERs on BPA's system. Section II includes a policy paper describing BPA's perspective on some of the biggest challenges that BPA and the Pacific Northwest face with respect the future of VER development. Section III includes BPA's responses to the specific questions in the Notice. The policy paper in section II provides context for BPA's responses to the specific questions in section III, but it does not necessarily address all of the issues raised in the questions in section III.

I. BACKGROUND

A. Regional Collaboration of Integration of VERs Since 2005

In 2005, the Northwest Power and Conservation Council (the "Council") released its 5th Power Plan, calling for up to 6,000 MW of regional wind development over the next 20 years. In response, BPA and the Council co-sponsored the Northwest Wind Integration Action Plan ("Action Plan"). This collaborative effort brought together the region's utilities, wind developers, regulators, renewables advocates and other stakeholders to determine whether it was technically feasible to integrate 6,000 MW of wind energy into the Northwest grid. The Action Plan also identified what it would take, in terms of infrastructure investment, operational changes, cost-recovery, and technology innovation to make wind work for the Northwest in a reliable and cost-effective fashion.

When the Action Plan was released in March 2007, it concluded that there were no fundamental technical barriers to integrating 6,000 MW of wind in the Pacific Northwest, but that realizing this objective would require: new transmission investments, better utilization of the region's non-hydro balancing resources through more robust voluntary markets for wind integration services, additional coordination between the region's multiple balancing authorities, improved analytical and forecasting techniques, and new cost-recovery mechanisms to ensure that the costs of wind integration services are appropriately borne by those creating the demand for such services.

The Pacific Northwest has since made substantial progress in implementing the Action Plan's recommendations. With respect to infrastructure development, several of the region's utilities are constructing or planning new transmission facilities that will help integrate thousands of megawatts of VERs. BPA's 2008 Network Open Season process, for example, resulted in signed commitments for 4,700 MW of new transmission service and, with the assistance of the American Recovery and Reinvestment Act of 2009 funding to expand BPA's borrowing authority, BPA is now building the 79-mile McNary-John Day 500 kV transmission line that will help bring additional wind energy from the eastern part of the Columbia River Gorge to load centers further west. BPA also has begun environmental review on three other proposed 500-kV projects totaling about 145 miles as a result of the 2008 Network Open Season. In the interim, BPA has made over 585 MW of offers of conditional firm transmission service, two-thirds of which will help to support the transmission of wind generation.

With respect to system operations, there have been several positive developments. In 2006, a number of balancing authorities in the region came together to develop an operational tool called Area Control Error Diversity Interchange. Through this tool, balancing authorities located throughout the Western Interconnection share momentary imbalances or control errors. This reduces control burden on generators, resulting in savings in operation and maintenance costs, improvements in control performance, and reductions in sensitivity to VER output. This tool was implemented at very low cost without requiring additional governance or regulatory oversight. Recently there have been some issues regarding application of BAL-001-0.1a to the initiative, but these issues should be resolved in the near term. This accomplishment is just one of many examples of regional coordination and problem solving efforts related to system operations that has defined the Pacific Northwest for many years.

The region is also advancing in the area of intra-hourly scheduling. A Joint Initiative among ColumbiaGrid, Northern Tier Transmission Group, and WestConnect has developed generic business practices for intra-hour transmission scheduling.[1] BPA and several other regional utilities have posted customized versions of those business practices and a voluntary, bilateral intra-hour market has begun to develop in the Northwest. The joint initiative is also developing an automated Dynamic Scheduling System as well as an electronic bulletin board to help reduce transaction costs and increase liquidity in the intra-hour market.

Based on the Action Plan and regional dialogue, the region has identified many of the issues associated with VER integration, and is actively working collaboratively to find and implement solutions. Through the Joint Initiative, the Western Electricity Coordinating Council ("WECC"), and other regional forums, the region's balancing authorities are now discussing other ways to build on the existing platform of collaboration to support wide-area optimization in ways that are consistent with regional values and regulatory and statutory obligations.

[1] These efforts are described in detail in the "Comments of the Joint Initiative Facilitators" filed in this docket.

B. Recovering the Costs of Balancing Reserve Capacity

In addition to operational and technical issues, the Action Plan identified the development of mechanisms to recover the costs of wind integration as a threshold issue. In 2007, BPA determined that a new rate was necessary to recover the costs of carrying capacity reserves to balance the within-hour variability of wind. Historically BPA has relied on the Federal Columbia River Power System ("FCRPS") to provide the capacity needed to balance variation in wind generation within the hour. BPA generally refers to the capacity reserve needed to account for within-hour variability as "balancing reserve capacity." The large-scale export of wind generation out of the BPA balancing authority has placed enormous pressure on the balancing capability of the FCRPS, because BPA stands ready to provide balancing reserve capacity and energy to support delivery of large quantities of wind to other balancing authorities. When the large, geographically-concentrated wind fleet in BPA's balancing authority experiences a significant ramp event (up or down), BPA sees substantial variations between the wind hourly schedules and the actual performance of the generators, which contributes substantially to the need for balancing reserve capacity. This balancing reserve capacity includes three components: regulation reserve (moment to moment balancing), following reserve (moment to 10 minute variation balancing), and imbalance reserve (balancing the difference between schedule and actual for the hour). BPA notes that in some forums, it is common to use the term "regulation" as a proxy for the totality of the within-hour balancing requirements for VERs, but through its rate cases and other operational forums, BPA has very explicitly disaggregated the total VER within-hour balancing requirement into these three components.

BPA first established a wind integration rate for Fiscal Year ("FY") 2009 to better align cost causation with cost allocation and send a price signal for the costs of balancing reserve capacity in the face of impending limits on FCRPS capability. BPA's first iteration of the wind integration rate did not include costs of the imbalance reserve component of balancing reserve capacity. Once BPA began work on the rate for FY 2010-11, its efforts quickly indicated that a substantial rate increase would be necessary because of the "imbalance reserve" component of balancing reserve capacity. BPA determined that a significant, and previously underappreciated, driver of the imbalance component of balancing reserve capacity was the inaccuracy of the wind schedules in BPA's balancing authority. Inaccurate scheduling by the wind fleet increased the need for balancing reserve capacity and the overall cost of balancing reserve capacity by a substantial amount. These concerns about the cost of inaccurate scheduling were enhanced by the fact that BPA forecasts indicated that wind generation in the balancing authority would increase significantly in FY 2010-11.

Quantifying the cost of inaccurate scheduling by a rapidly growing wind fleet got the attention of the regional wind community and other key stakeholders, and these groups immediately began to communicate the importance of high quality wind forecasting and accurate scheduling. Soon after publication of BPA's proposed FY 2010-11 wind integration rate proposal, BPA began to observe improvements in scheduling accuracy. Within three months, scheduling accuracy had improved substantially. BPA ultimately set its FY 2010-11 rate based on assumptions about more accurate scheduling by the wind fleet, which reduced the rate substantially compared to the initial proposal.

C. BPA's Wind Integration Team and Dispatcher Standing Order 216

BPA has assembled a cross-agency Wind Integration Team ("WIT") to further address the technical issues identified in the Action Plan, FY 2009 rate proceeding, and other regional forums. One of the first accomplishments of the WIT was the development of operational and reliability protocols designed to maintain system reliability when wind variability exhausts the incremental and decremental balancing reserve capacity established on a planning basis.[2] The WIT developed these protocols after BPA began analyzing the FCRPS' capability to provide sufficient balancing reserve capacity to maintain reliability during extreme wind ramps. BPA codified the protocols in Dispatcher Standing Order 216 ("DSO 216") in October 2009.

The DSO 216 protocols have two essential features: when *unscheduled increases* in wind generation and load exhaust the FCRPS' decremental balancing reserve to ramp Federal generation down, dispatchers send reliability directives via electronic signals to the wind fleet requiring reductions in wind output (feathering) to preserve load and resource balance within the BPA balancing authority. When *unscheduled reductions* in wind generation and load exceed the FCRPS' incremental balancing reserve to increase Federal generation to respond with imbalance energy, dispatchers adjust wind transmission schedules down to reflect the lower wind output levels. For wind generation exports in these extreme under-generation cases, the load serving entities in the receiving balancing authorities must rely upon their own resources to make up any difference. BPA activated the current DSO 216 protocol in October 2009, and so far the DSO directives have only been activated a few times each month.

Although BPA developed DSO 216 initially as a reliability backstop tool, it has served a commercial purpose by allowing BPA and wind generators to balance quality of service with costs. In the last rate case, BPA forecast the amount of balancing reserve capacity needed to

[2] Incremental reserves are reserves required to maintain load-generation balance when an under-generation situation exists within the BPA balancing authority area. In an under-generation situation, instantaneous loads are higher than planned or the instantaneous wind generation is lower than planned. Under these circumstances, the FCRPS generation must automatically increase to maintain system balance. The incremental reserve is the amount that the FCRPS must be capable of instantaneously increasing generation. Conversely, decremental reserves are reserves required to maintain load-resource balance when an over-generation situation exists within the BPA balancing authority area. In an over-generation situation, instantaneous loads are lower than planned or the instantaneous wind generation is higher than planned. Under these circumstances, FCRPS generation must automatically decrease to maintain system balance. The decremental reserve is the amount that the FCRPS must be capable of instantaneously decreasing generation. BPA forecasts the incremental and decremental balancing reserve requirement on a two-year planning basis coinciding with its rate proceedings.

firm up hourly transmission schedules from VERs during the rate period. As described above, the assumption about the scheduling accuracy of the wind fleet was a primary driver of the amount of capacity that BPA would need. Wind developers and operators encouraged BPA to assume that the wind fleet would schedule more accurately during the rate period than the fleet had historically, because assuming more accurate schedules would reduce the overall amount and cost of balancing reserve capacity that BPA would make available. In other words, they advocated that BPA should carry—and charge—for a lower quantity of available balancing reserve capacity. In exchange for BPA limiting the wind integration rate increase by making less balancing reserve capacity available, however, wind generators essentially were accepting a lower quality of service because the likelihood of feathering or curtailments under DSO 216 would increase.

The tradeoff between cost and quality of service through the amount of balancing reserve capacity available before BPA applies DSO 216 has raised questions about the deployment of other types of reserves for wind balancing. Because substantial VER generation is exported from BPA's balancing authority, BPA has called upon DSO 216 to "clip the tails" of wind ramps at times to maintain reliability of the BPA balancing authority when the planned balancing reserve capacity is exhausted. The use of DSO 216 to curtail firm transmission schedules associated with exported wind energy is forcing re-examination of the traditional ways of carrying contingency reserves for VERs. BPA addresses this issue in Part II below.

In collaboration with regional stakeholders, the WIT is also developing new wind forecasting and situational awareness tools for dispatchers. The WIT is managing the development and implementation of three pilot projects related to wind integration in the areas of dynamic transfer, intra-hourly scheduling, and customer self-supply of balancing reserve capacity.

II. MAJOR POLICY POSITIONS

Despite the region's considerable progress on the wind integration front, there remain some substantial challenges. These challenges have arisen from the sheer pace and geographical concentration of wind development in the region. Whereas the Council's 5th Power Plan called for the development of 6,000 MW of wind in the next 20 years (with an implicit assumption that approximately half of this development would occur on the BPA system), BPA may see as much as 6,000 MW of wind interconnected to the BPA system alone as early as 2013. Much of the demand for this wind energy is driven by non-Federal utilities, with an increasing amount of wind development responding to the needs of state renewable portfolio standards.

As utilities across the country continue their search for renewable resources outside of their service territories, the challenges associated with large-scale exports of VERs are raising complex policy, planning, and cost allocation issues. The topic of VER exports is becoming increasingly important because most of the country's best potential renewable energy resources are located in regions that are remote from load centers. While the Pacific Northwest is taking meaningful and deliberative steps to increase coordination between the region's multiple balancing authorities and developing intra-hour transmission scheduling business practices, there are important policy and tariff issues that present significant barriers to the region's evolution towards more efficient mechanisms for wide-area optimization. These issues—in particular those associated with load service responsibility, Schedule 9 of the *pro forma* tariff, and the development of standardized methodologies for quantifying balancing reserve capacity requirements—are discussed further in Part III and the subsections below.

A. The Value and Importance of High Quality VER Forecasting, Accurate VER Scheduling, and Refined and Innovative Operational Tools

One of the most important drivers of efficient balancing reserve capacity utilization and reduced costs is forecasting accuracy. With a perfect hourly wind forecast, wind energy could essentially be wheeled across the exporting system with only the balancing reserve capacity for the physical movement of VERs in the regulating (*i.e.*, seconds) and following (*i.e.*, minutes) timeframes. However, because wind forecasts are imperfect, some additional amount of balancing reserves capacity to capture imbalance energy exposure will need to be carried in the overall system.

Improved forecasting accuracy can dramatically reduce the amount of balancing reserve capacity required to firm up VER schedules. BPA's last rate case valued improved wind forecasting at about $60 million per year for the rate case average forecast of 3200 MWs of installed wind capacity. Forecasting large wind ramps in particular is very valuable, as the big up and down ramps typically consume the largest quantities of balancing reserve capacity. It is important to recognize that good utility practices require that all generators, including VERs, schedule as accurately as possible using the best technology available. Leaning on the balancing authority or being overly dependent on a balancing capacity market instead of investing in readily available and cost-effective forecasting tools is unacceptable and likely to lead to higher integration costs, which are typically passed on to consumers. Although the industry has already made significant progress in improving forecasts, more development is needed in areas of infrastructure and data processing.

The support and development of high quality wind forecasting and situational awareness tools for dispatchers requires incentivizing the best possible forecasting and aligning the interests of wind generators with the needs of system operators. BPA exempted wind generators from the most expensive penalty band of the generation imbalance rate in 2002. Experience with this exemption, however, has taught BPA that providing generation imbalance service to a large and variable wind fleet requires significant amounts of capacity as well as, safeguard mechanisms to minimize persistent schedule deviations. This is particularly important on an interconnected hydro system when the accumulation of significant station control errors and associated generation imbalances can conflict with non-power operating constraints, such as meeting Endangered Species Act requirements (*e.g.*, required flows to support fish migration and spawning).

B. The Operating Dynamics of Wind Energy and the Specific Challenges of Exporting Wind Between Balancing Authorities

The primary role of wind generation in a utility portfolio is to displace fossil fuel consumption along with its associated air quality and greenhouse gas emissions, and reduce exposure to volatile fossil fuel prices. Because of its dependence on the natural variability of the earth's atmosphere, wind power is primarily an *energy* resource, rather than a *capacity* resource. When it gets very hot or very cold (*i.e.*, periods of peak utility loads) across the footprint of BPA's balancing authority area, BPA typically sees little to no wind generation. As a result, regional load serving entities must ensure that they have sufficient peaking capacity to meet their load obligations when the wind is not blowing.

Whereas utilities have had to manage the natural variability and uncertainty of loads for many years, most traditional generating resources have been dispatchable, especially during the time horizon of within-hour operations. With the entry of wind generation and other VERs, utilities are adding generating resources that are no longer dispatchable in the traditional sense and—at sufficient penetration levels—increase the overall uncertainty and variability of system operations. This increased variability and uncertainty increases the demand for system flexibility—the system's dispatchable generating resources (and loads) must now be prepared to move both to a greater degree and more frequently outside of the traditional load ramping periods to accommodate physical swings in wind output and wind forecast errors. These issues become significantly more complex in the case of exports between balancing authorities. To better illustrate this point, consider the following two cases.

<u>Case 1:</u> A load serving entity with its own balancing authority buys wind energy located inside its balancing authority for its own load service.

The load serving entity must have sufficient base load generation, peaking capacity, and system flexibility to follow load across all relevant time horizons. With the addition of wind to the load serving entity's resource portfolio, the load serving entity will have an incentive to forecast wind output with maximum accuracy. Based on its forecast, the load serving entity will ensure that generating capacity is available to balance the projected wind variability. Since wind forecasts are not perfect, however, the wind resource will add more operational uncertainty to the load serving entity's system and will place greater demands on the load serving entity's dispatchable generating resources.

As long as the load serving entity's dispatchable generating resources can provide sufficient flexibility and balancing reserve capacity to manage the incremental variability and uncertainty created by the wind, the system can reliably manage its aggregate system obligations. However, if the additional ramping requirements created by the wind resource exceed the flexibility of the load serving entity's system, the load serving entity may need to procure additional balancing resources.

There is some overlap between the needs for system flexibility and peaking capacity—for example, natural gas-fired power plants are often a source of both system flexibility and peaking capacity. But the need for flexibility is different than the need for peaking capacity and the distinctions in the various uses of generating capacity may not be captured in traditional utility planning for peak generation. Wind in this case may increase the demand for *flexibility* on the load serving entity's system, but the wind is not a net consumer of the load serving entity's *peaking capacity*.

Case 2: The load serving entity above purchases wind energy for load service, but the wind generator is located in an adjacent balancing authority.

Whereas in Case 1, there is *one* entity responsible for meeting the peaking capacity requirements of load and the flexibility needs of the VER, in Case 2, both the load serving entity (in this example, the importing or sink balancing authority) and the balancing authority in which the VER is physically located (the exporting or source balancing authority) have capacity obligations. Because the wind generator will not produce any energy in many hours, the load serving entity still has to have access to capacity resources to keep the lights on when the wind is not blowing. However, in this case the load serving entity's peaking capacity and balancing resources are not available to the source balancing authority, which must manage the variability and uncertainty of the VER during the period between interchange schedule adjustments, which traditionally occur each hour. As a result, the source balancing authority must also provide balancing reserve capacity to ensure that the amount of scheduled wind energy is delivered to the sink balancing authority. This leads to potential gaps or duplication of capacity obligations. Since the load serving entity is unlikely to have enough information prior to the scheduling period to make secondary sales of machine capacity that would be enabled by the scheduled firm wind generation, this translates into additional peak capacity and system flexibility requirements for the overall electric system.

Separating the obligation also creates challenges under minimum generation or restricted energy content conditions. The load serving entity no longer is responsible for managing the complete portfolio of resources and is largely isolated from the consequences of the within-hour behavior of its imported resource. Instead of the load serving entity rationally adjusting VER output when system conditions warrant, the VER operates as "must run" generation within the source balancing authority, not because of physical or system requirements, but because it is not being operated with the needs of the source balancing authority in mind. BPA has taken a number of steps to begin to address this issue by aligning VER operation with the needs BPA's system. The most prominent of these is DSO 216.[3]

C. <u>Options for Solving the Problems Imposed by Exporting VERs Between Balancing Authorities</u>

In addition to the potential for duplication of capacity obligations, BPA is currently looking to address another issue associated with VER exports, which arises due to the curtailment of transmission schedules under BPA's DSO 216. In the Pacific Northwest, when BPA curtails wind schedules during times when wind is generating significantly less than the scheduled amount and BPA is close to running out of balancing reserve capacity to supply the power the wind generators are not producing, the sink balancing authority will not receive the total scheduled amount of energy and must rely on other resources to make up the difference. These occurrences are fairly rare, but raise a set of issues that need to be addressed in the context of scheduling protocols, contingency reserves, and load service responsibility.

Development of intra-hour scheduling in the Northwest will likely help provide some alternative sources of balancing reserve capacity and energy during those times when BPA's or other balancing authorities' total available or contractually obligated balancing reserve capacity

[3] For description of DSO 216 see Part I, Section C, pp. 12-15.

has been exhausted. With sufficient intra-hour market visibility and liquidity, a load serving entity exposed to a DSO 216 type of curtailment will have the option of relying on its own resources or purchasing balancing reserve capacity and energy from a third-party seller for the duration of the scheduling period.

Because the intra-hour market in the Pacific Northwest is still in its infancy, the dialogue around the impacts of DSO 216 curtailments has mostly concerned whether such events should qualify as contingency events and allow for the deployment of contingency reserves. There is logic to this thinking, as it is inefficient for balancing authorities that are exporting wind to carry balancing reserves for the full range of variability of a large wind fleet. As a result, deploying contingency reserves for so-called "tail events" (*i.e.*, statistically infrequent events) may make sense. BPA notes, however, that the behavior of wind plants under all circumstances may not resemble traditional contingency events. Over time, it may be more appropriate to treat *all* of the reserve requirements for wind projects as balancing reserve capacity, rather than creating a set of qualifying events for contingency reserves. This would liberate wind projects from having to purchase contingency reserves and would create additional incentives for a more robust intra-hour market for balancing energy. BPA will continue to engage this topic with regional stakeholders through the Northwest Power Pool and other forums.

In Order 890, the Commission adopted generator imbalance service as a new ancillary service. The Commission required transmission providers to offer generator imbalance service to all generation in the transmission provider's system to the extent it is physically feasible from the transmission provider's resources or from resources available to it. Based on the language in the *pro forma* Schedule 9, it is possible that some may interpret the transmission provider's role to be a default supplier with an unlimited responsibility to supply balancing reserve capacity.

From BPA's perspective, interpreting the Commission's *pro forma* Schedule 9 to mean that the source balancing authority has an unlimited responsibility for carrying balancing reserve capacity for exports would be at odds with the basic principle of load service responsibility. As noted above, the Schedule 9 approach fosters economic inefficiency because the load serving entity in the sink balancing authority is already planning for its peak capacity needs, and placing an open-ended capacity requirement on the source balancing authority is duplicative from the perspective of generation capacity. In fact, based on BPA's experience with the issues associated with exports, BPA is convinced that the principle of load service responsibility should apply to more than just contingency reserves. *BPA believes that the VER owner and the entity that is using the VER for its own load service should have the fundamental planning, operational, and financial responsibility for ensuring that there is sufficient capacity available to manage the full range of variability of the VER—including regulation, load following, generator imbalance, and extreme tail events (big up and down ramps).* As discussed further below, such responsibilities could be met by requiring the VER owner/operator/purchaser to develop and submit an explicit balancing plan for its resource.[4]

Such an approach does not relieve exporting balancing authorities of its responsibilities. In addition to their other critical responsibilities associated with ensuring system reliability and operational functionality, exporting balancing authorities should strive to provide options for wind exporters and purchasers to procure balancing reserve capacity from alternative providers and mechanisms, such as self-supply, intra-hour scheduling, and dynamic transfer, without risking reliability and where value equals or exceeds the cost of providing the services.

[4] Recognizing that many load serving entities that purchase VER generation are not balancing authorities, BPA recommends that these non-balancing authority load serving entities must coordinate with the VER developer as well as the source and sink balancing authorities to meet the capacity needs of the VER.

If, however, after considering other options, the VER submits a balancing plan indicating that it still prefers to procure some or all of its balancing reserve capacity from the source balancing authority, the source balancing authority can enter into a commercial transaction for such balancing reserve capacity with full cost recovery and risk protections for its preference or native load customers. The obligations of the source (exporting) balancing authority should be limited to the quantity of capacity for which it has contracted with the VER. If the VER's chosen portfolio of balancing reserve capacity (including purchases from the source balancing authority) is insufficient to manage the balancing needs of the VER, it is the VER operator or buyer and the sink balancing authority that should be accountable for making up any balancing shortfalls. This distinction between being a default supplier as opposed to a fully compensated party to a clearly defined and delimited commercial transaction is essential to the sustainable growth of VERs in exporting regions.

In the following sub-sections, BPA further elaborates on options for providing balancing services as well as the specific mechanisms by which exporting balancing authorities can clearly define and delimit their balancing reserve obligations.

1. Dynamic Transfer

The most direct way of changing the balancing reserve capacity responsibility for VERs from source to sink balancing authorities is through dynamic transfer.[5] Dynamic transfer presents one potential solution to the cost and efficiency issues associated with exports. In contrast to the scenario in which the within-hour balancing obligation resides with the source, shifting the balancing responsibility to the sink balancing authority that is using the VER for load service would minimize capacity and flexibility duplication. It would also create stronger

[5] Dynamic transfer is the means by which the electrical output of a generating resource is balanced in real-time by an entity other than the balancing authority in which the resource resides. Included in the definition of dynamic transfer are both dynamic schedules and pseudo-ties.

incentives for cost-reduction, retrofitting of existing generation for greater flexibility, and the development of more robust voluntary intra-hour markets for balance reserve capacity. With the establishment of such markets, an entity like BPA could participate by making discretionary surplus sales of hydro-system capability during those periods when it was the most cost-effective resource for a particular increment of balancing reserve capacity demand. BPA notes that at least one of California's larger investor owned utilities is exploring the use of pseudo-ties between the Northwest and California to transfer the variability of wind projects located within the BPA service territory to the California ISO's balancing market.

BPA notes that although dynamic transfer may be mutually advantageous and economically efficient in some situations, it is not a panacea. There are significant technical limitations to the expanded use of dynamic transfers, which are described more fully in Part III, Section B.1, question three responding to the Commission's specific questions. There are also infrastructure costs associated with moving regulating and following signals across long distances. Those costs need to be weighed against the savings using the peaking resources located near the load and the relative costs of new regulating and following capacity in each area. If investment and operational costs associated with increasing dynamic transfer are to be incurred, transmission providers need mechanisms to recover those costs from the entities creating the demand for the new service.

Having each balancing authority independently meeting its balancing reserve capacity needs does not take full advantage of VER diversity between balancing authorities, which includes effects of load variability between balancing authorities, and deploying the most cost-effective balancing reserve capacity resources. BPA and other Northwest balancing authorities are working together to explore the development of cost-effective mechanisms that support wide-area optimization in the provision of balancing reserve capacity. Although dynamic transfers may not be appropriate in all situations, it is BPA's belief that placing the load service responsibility for balancing reserve capacity with sink balancing authorities is a necessary *precondition* of such broader market mechanisms since it will clearly define which entities are driving the need for balancing reserve capacity, clarify cost causation and cost allocation, and increase incentives for the development of capacity markets because the same entities that are receiving the benefits of the VERs will have increased motivation to search for the least-cost solution to their balancing reserve capacity needs. From BPA's perspective, clearly defined load service responsibility and wide-area optimization go hand in hand.

2. Balancing Plans

Any good management or regulatory system creates clarity as to which entity has accountability for specific outcomes. It is BPA's view that the accountability for assuring that adequate balancing reserve capacity is available for VERs that export generation from a balancing authority should rest with the buyers and the sellers of the VER generation, not the source balancing authority. The buyers and sellers can best determine the quality of service and cost they prefer. The source balancing authority should not be a default supplier of balancing reserve capacity particularly when other options are available for obtaining balancing reserve capacity.

A first step toward establishing clear responsibility and a more diversified and clearly defined set of alternatives for balancing reserve capacity is to require VER owner/operators/buyers to develop and submit balancing plans for their VERs.[6] These balancing plans should become one of the interconnection customer requirements contained in the

[6] In the case where the VER is not sold under a long-term power purchase agreement, the VER owner should be responsible for providing a balancing reserve capacity plan to the source balancing authority.

Commission's standard Large Generator Interconnection Agreement ("LGIA") and Small Generator Interconnection agreement ("SGIA"). Through such a process, the interconnection customer would be required to determine and document for the transmission provider the interconnection customer's specific strategy for procuring balancing reserve capacity for its VER. The applicant could elect to dynamically transfer the resource off of the source balancing authority's system to the extent such capability is available between the source and sink balancing authority, self-supply all or a portion of its needs from resources within the source or sink balancing authority's service territory, or purchase all of its balancing reserve capacity directly from the source balancing authority. With this information in hand, the source balancing authority could then more effectively plan the balancing reserve capacity requirements of its system.

Consistent with the spirit of Schedule 9 of the *pro forma* tariff, the source balancing authority would quantify, post, and make available sales of balancing reserve capacity from its own resources that are net of its other statutory reliability, non-power (*e.g.*, fish and wildlife), contractual, and preference or native load obligations. The source balancing authority would provide balancing services up to this net amount of balancing reserve capacity (or, potentially, a smaller amount if the source balancing authority must reduce the amount of capacity available on a planning basis in accordance with good utility practices or, in the case of an entity like BPA, statutory obligations).

In addition, the source balancing authority should be allowed to determine an operating margin for balancing reserve capacity requirements to prevent being pushed to the edge of reliable system operations by VERs. This could be accomplished, for example, by limiting the amount of total decremental capacity available on the source balancing authority's system from its own resources to avoid minimum generation violations. This approach is analogous to the concept of a Transmission Reliability Margin and it would need to be subject to clear rules to prevent inefficiencies and abuses.

If the net demand for balancing reserve capacity for the VER resources interconnected to the source balancing authority exceeded the available capacity from existing balancing authority resources, the balancing authority would run an acquisition process for additional balancing reserve capacity and assign the incremental costs of such balancing capacity to the entities or class of entities driving the need for such capacity. The source balancing authority must recover all the costs and cover all risks associated with such an acquisition. The most likely acquisition timeframe would be across the rate period, but longer-term acquisitions could be accomplished with the requisite cost-recovery and stranded cost provisions.

Until markets develop further for these resources, it may take time for the source balancing authority to acquire the capacity resource. Since reliable operations depend on having adequate amounts of balancing reserve capacity, there may be higher incidences of reliability related VER generation reductions and schedule curtailment events. This approach would operate in much the same fashion as requests for additional transmission capacity that must wait for facilities to be built to accommodate the additional capacity needs or rely on conditional firm service and other non-firm products until the new facilities are completed. Similarly, there should be a commitment period, so that a source balancing authority that acquires balancing reserve capacity resources to meet a request does not face stranded cost risks if the requestor chooses another alternative to meet its balancing requirements.

The source balancing authority would need to maintain a mechanism like DSO 216 to limit its balancing reserve capacity responsibilities to its firm contractual commitments to provide such services and maintain reliability. In this approach, it is ultimately the planning, operational, and financial responsibility of the user of the VER to ensure the availability of sufficient balancing reserve capacity, but the balancing authorities play an important commercial facilitation and cost allocation role for the delivery of such capacity. This approach is compatible with dynamically transferring VERs to sink balancing authorities, but also leaves open the potential for economically efficient transactions that allow sharing of balancing reserve capacity requirements and ensures that source balancing authorities play an active role in supporting VER development without assuming inappropriate financial obligations. For example, the source balancing authority could sell balancing reserve capacity to manage the regulation and following components, and the sink balancing authority could maintain reserves to manage the imbalance and contingency reserve components of the VER. This type of arrangement would not require dynamic transfer capability, but would have the benefit of reducing the system flexibility and capacity obligations of the source balancing authority, and tap into the peak capacity already accounted for in the sink balancing authority's capacity obligations to meet its load.

Although BPA intends to support the development of operational solutions that will mitigate the need and downstream impacts of curtailments under DSO 216, BPA believes that a mechanism such as DSO 216 is an essential part of BPA's operational toolbox for the foreseeable future. Such operational and reliability protocols may require re-examination of product definitions and tagging protocols for VERs. BPA's aim is to maintain the value of renewable energy resources in the marketplace while promoting a more rational and efficient distribution of the responsibility for planning and paying for balancing reserve capacity.

Under the balancing plan framework, the source balancing authority provides the VER developer or load serving entity with options for how to meet the balancing reserve capacity needs of its resource. As a result, it may be appropriate for the source balancing authority to be given the discretion to charge incremental or market-based rates for the use of its balancing reserve capacity. This type of pricing discretion is likely necessary if the Northwest is to see the development of new markets for balancing reserve capacity and to prevent the hyper-concentration of balancing obligations on source balancing authorities that are otherwise required to sell at embedded cost rates.

D. Impacts on Wholesale Energy Markets and Non-Power Constraints

The discussion of how to successfully integrate VERs cannot ignore the impact of VERs on the wholesale energy market. BPA has observed that production incentives, which are important mechanisms for achieving public policy objectives, have the unintended consequence of incentivizing VERs to attempt to maximize their generation under all conditions, even during periods when the incremental value of their generation to the system is extremely low or may conflict with non-power constraints, such as endangered species protection. Such production incentives also motivate VERs to generate above and beyond their scheduled output.

There also appears to be a correlation between the significant increase in VERs and the occurrence of negative market prices. Such occurrences appear to be a further reflection of the incentives mentioned above. When market prices are extremely low or negative, traditional generators respond to these price signals and will shut down or reduce generation. The operating incentives provided to VERs dampen these price signals and they will continue to operate up until the point at which their costs of finding a sink for their energy exceed their incremental revenues from tax and renewable energy credits.

These problems are worse during light load hours, but there is also an impact during heavy load hours. For example, excessive over generation by the wind fleet during constrained water conditions can push BPA's hydro system to the brink of violating Endangered Species Act and Clean Water Act obligations. These conditions are creating a trade-off between meeting statutory and environmental obligations and, where there are no other options, potentially having to pay VERs the value of their production tax credits and renewable energy credits to not operate. Ultimately, solutions to the dramatic growth of VERs need to address these impacts on the energy market and ensure proper controls on behavior that may negatively impact energy markets or contribute to potential violations of Federal and state environmental laws.

E. Renewable Energy Credits

The use of renewable energy credits to meet renewable portfolio standards can create greater economic efficiency in the market place. However, unbundling of renewable energy credits, which allows the credits and attributes to be sold separately from the energy produced by VERs tends to make most of the issues described above worse. The separation of the credits and attributes from the physical power makes it possible to export the credits and attributes while leaving the "brown power" and its variability in the source balancing authority or region. This exacerbates the reliability challenges and impacts of negative pricing associated with VERs. All these other issues must be addressed in order for renewable energy credits and attributes to be disposed of separately in the market place. BPA is actively engaged with regional stakeholders to develop durable solutions to these issues.

F. Policy Summary

The development of significant amounts of VERs for export has had a significant impact on the operation of the electrical system and challenged the ability of source balancing authorities to meet their many reliability and operational obligations. Unless these issues are resolved, source balancing authorities for exported wind will experience reliability or cost consequences that will almost certainly have a negative impact on future resource siting and development in host regions.

A multifaceted solution is needed to ensure a rational operating and cost recovery environment for VERs and affected balancing authorities. BPA and other Pacific Northwest balancing authorities—both Commission jurisdictional and non-jurisdictional—met recently to discuss many of these issues and there is significant agreement around accelerating the efforts to implement intra-hour scheduling and to better quantify and expand dynamic transfer capability. There was some discussion of creating an independent market coordinator to facilitate an intra-hour balancing reserve market, although several entities have outstanding concerns regarding how this would work in terms of statutory requirements and jurisdictional status. Balancing authority consolidation feasibility studies are currently underway and BPA is committed to analyzing these studies to evaluate the cost and benefit associated with pursuing consolidation further. In exploring such options, BPA remains concerned about Commission jurisdiction over a consolidated entity. The Commission should encourage these ongoing efforts for regional solutions, but not require consolidation of balancing authorities to address the issues raised by the rapid and large-scale increase in VERs.

BPA intends to continue to work on strategies that will reduce the cost and total demand for balancing reserve capacity, address the inefficiencies and inequities of multiple balancing authorities in a fashion that is consistent with regional values, and support continued technical and policy innovation on the topic. These major policy positions are reflected in BPA's answers to the specific questions of the Notice addressed below.

including VERs, comply with all BPA dispatch instructions. This penalty charge has worked well at incentivizing compliance with BPA reliability directives. As the level of VERs increases within a balancing authority area, BPA believes that system operators will need financial incentives such as penalty charges for non-compliance to ensure that generators follow all dispatch directives and to protect system reliability.

IV. CONCLUSION

BPA thanks the Commission for its efforts to address the complex issues involving the integration of VERs and appreciates the opportunity to provide comments. To the extent that the Commission identifies the need for revisions to the Commission's policies or procedures, BPA supports changes that reflect BPA's recommendations and that account for regional variations.

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Respectfully submitted,

/s/ Todd E. Miller
Todd E. Miller, Attorney
Marcus H. Chong Tim, Attorney
Matthew W. Perkins, Attorney
Bonneville Power Administration
Office of General Counsel – LP-7
P.O. Box 3621
Portland, OR 97208
Telephone: 503-230-7315
Facsimile: 503-230-7405
Email: temiller@bpa.gov