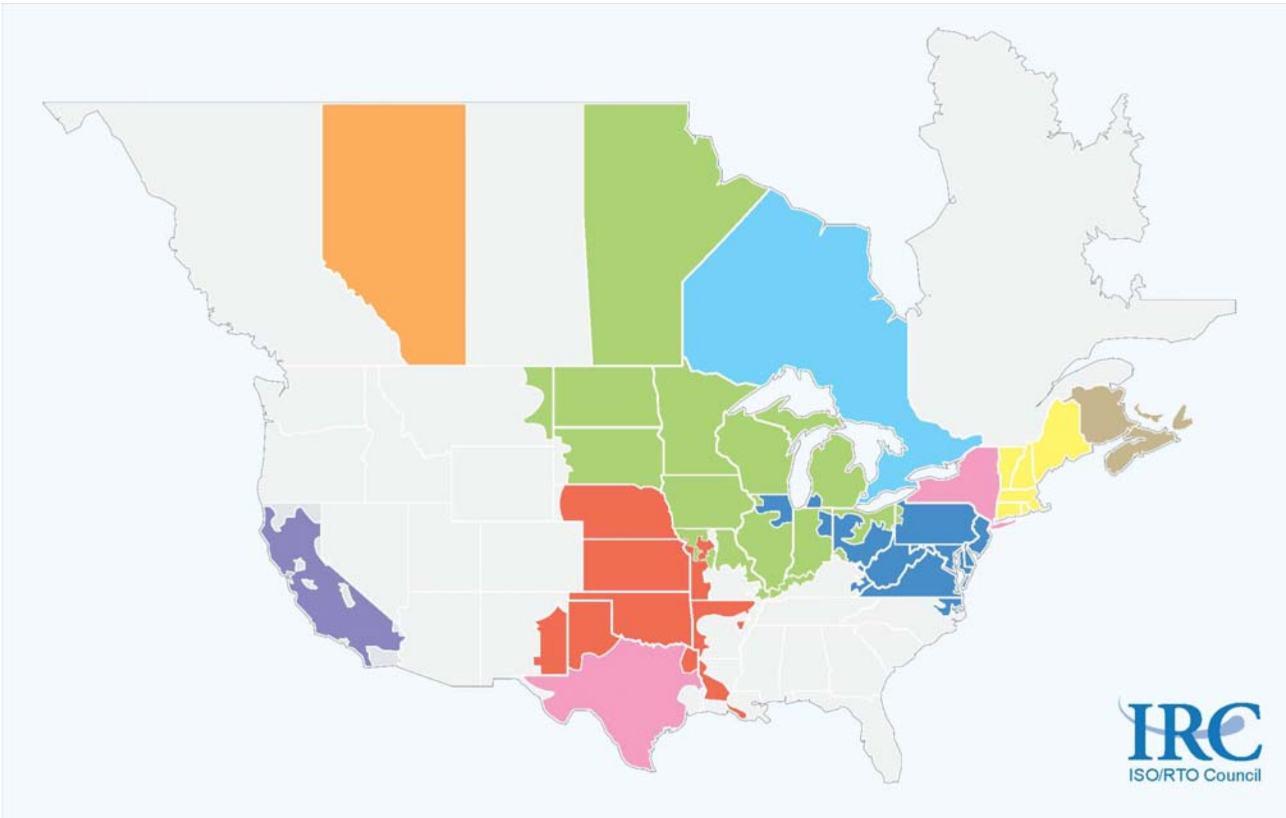

ISO/RTO Council Briefing Paper

Variable Energy Resources, System Operations and Wholesale Markets

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In response to the Federal Energy Regulatory Commission's Notice of Inquiry on Integration of Variable Energy Resources (Docket No. RM10-11-000), the IRC submitted the white paper, *Variable Energy Resources, System Operations and Wholesale Markets*. The Alberta Electric System Operator (AESO), California Independent System Operator (CAISO), Electric Reliability Council of Texas (ERCOT), Ontario's Independent Electricity System Operator (IESO), ISO New England, Inc. (ISO-NE), Midwest Independent Transmission System Operator, Inc. (Midwest ISO), New York Independent System Operator (NYISO), New Brunswick System Operator (NBSO), PJM Interconnection, L.L.C. (PJM), Southwest Power Pool, Inc. (SPP), and KEMA assisted in the preparation of the white paper. This briefing paper presents a summary of that report.

1. Introduction

Independent System Operators and Regional Transmission Organizations (ISOs/RTOs) play a vital role in facilitating the integration of variable energy resources (VERs). These renewable resources (primarily wind and solar) are currently seen as the resources most likely to fulfill the objectives of state and provincial renewable energy targets, feed-in-tariff programs, as well as national and regional climate policy goals.

By addressing the challenges of integrating VERs, ISOs/RTOs are helping to facilitate the achievement of these policy goals. In some cases, achieving these goals will require an unprecedented pace of capacity additions and system operational changes – a pace that can only be supported by the flexibility and adaptability of competitive wholesale markets.

This paper looks at the challenges ISOs/RTOs face, and the efforts they have taken, and will need to take, to integrate VERs. The variable nature of these resources poses challenges to system operators and market designers. Conventional generating resources are relatively stable, schedulable, and controllable, and market rules and system operating procedures were originally designed around these characteristics. VERs, on the other hand, are intermittent by nature and are influenced by factors such as weather and geographic location that must be factored into forecasting and system management.

But the challenges associated with integrating VERs are not limited to the accuracy of weather forecasts. Systems, products, and procedures need to be put in place to obtain and utilize forecasts, improve visibility of VERs, upgrade control centers and equipment, mitigate the intermittent nature of VERs, and modify operating procedures as required.

In addition to these operational challenges, the successful integration of VERs will also require adjustments to the competitive marketplace. Bidding and dispatch procedures may need to be changed, ancillary services procurement may need to be adjusted, and the impact on energy prices and capacity markets will need to be monitored.

2. Forecasting VER Production

There are two key characteristics of VERs that pose challenges to their integration: high forecast errors, and the inherent variability of production. Reducing forecast error is vitally important to efficiently integrating VERs. In addition, there will be interplay between the VER forecast errors and load forecast errors that may mitigate or exacerbate the net impact on system and market operations. To that end, ISOs/RTOs have become major consumers of VER forecasting services, and are both driving the VER industry to improve its provision of data to improve centralized forecasts as well as providing market-driven incentives for improvement of decentralized forecasting.

ISOs/RTOs are also utilizing forecast data in new or upgraded operational and market tools, including real-time visualization capabilities that will help system operators develop situational awareness, and probabilistic ramp forecasting that may increasingly inform unit commitment and dispatch over time.

Centralized Forecasting Methodologies

ISOs/RTOs have been leading the development of centralized VER forecasting since 2004, when CAISO established the first such ISO/RTO program in the U.S. under its Participating Intermittent Resource Program (PIRP). Most ISOs and RTOs find that they can achieve a better aggregate VER forecast using a centralized forecast than if they were to obtain the sum of the forecasts developed by VER operators. Formal, centralized processes for forecasting wind energy have been established in most ISOs/RTOs. In the remaining ISOs/RTOs, such processes are under evaluation. In addition, CAISO has recently begun to develop a centralized solar energy forecast.

Of the ISOs/RTOs that have centralized forecasting systems for VERs, one of three commercial vendors is used. PJM and Midwest ISO currently use the Energy & Meteo GmbH system; CAISO, ERCOT, and NYISO currently use AWS Truepower Services, but with some differences in inputs and applications; and AESO uses WEPROG.

Some ISOs/RTOs are considering developing centralized forecasting systems that utilize multiple forecast sources either under contract or through voluntary relationships.

VER data is a crucial input into the centralized forecasts. ISOs/RTOs generally require VER operators to provide forecasters with a range of real-time meteorological data, such as wind speed/direction, barometric pressure, humidity, and ambient temperature as well as current megawatt (MW) output and availability, along with physical data such as power curve, location, and hub height. Turbine availability is also very important because it indicates to the forecaster if the VER operator is experiencing outages on one or more turbines.

Forecast Timing and Accuracy

Until recently, VER scheduling in ISOs/RTOs was conducted hour-ahead using forecasts provided in that timeframe. More recently in systems with high and increasing VER production, day-ahead forecasting has become more important and efforts are being made to improve such forecasts for ISOs/RTOs' reliability unit commitments and to encourage additional day-ahead VER scheduling.

Practices vary in how these forecasts are incorporated into the scheduling process. Currently, in the day-ahead timeframe, VER forecasts are only advisory with no binding schedules or commitments. In the hour-ahead timeframe, the scheduling process is either bid-based or VERs are self-scheduled by a market entity based on the vendor forecast for that resource.

Given that targeted VER penetration levels are expected to be around 20% to 33% of total energy production over the next 10 years in most jurisdictions, ISOs/RTOs are planning to continuously evaluate and improve their forecasting practices. VER forecasting will need to be improved in the day-ahead and two-hour-ahead timeframes as well as in the shorter-term (15 minutes and less) timeframes, that affect quick-start unit commitments and economic dispatch instructions.

Forecasting accuracy is quantified in terms of magnitude and frequency of forecast errors, as well as the capability during particular periods of the operating day, and of increasing importance the ability to predict changes in expected wind output over periods of time. Errors in the day-ahead forecast typically range from 6% to 10% Mean Absolute Error (MAE) of installed capacity, but several ISOs/RTOs have measured errors of more than 10% MAE. Aggregate forecast errors for the wind farms within a market or balancing area less than individual wind farms due to diversity.

A particularly important forecasting problem is the ability to accurately forecast the onset, severity, and timing of significant increases or decreases in wind output resulting from changes in wind speed and high-speed cutouts of VER production resulting from excessive wind speeds. Locational VER forecasts will need to be improved in order to manage these types of events.

Another issue in some ISOs/RTOs is the ability to forecast VER production from distributed resources located on distribution circuits or "behind the meter". These resources are currently invisible in many ISOs/RTOs but are subject to the same meteorological effects as grid-connected VERs.

Improving Forecast Accuracy

Accurate forecasts rely fundamentally on high quality data made available in a timely manner to the forecast providers for use within their models. All ISOs/RTOs have experienced the effect of poor data quality on forecast accuracy, requiring improvements where necessary to telemetry data from VER sites.

In addition, ISOs/RTOs have found that the turbine outage information of the wind plant must be provided within a reasonable time after a forced outage or de-rate is detected. Scheduling of planned turbine outages and de-rates also generally needs improvement with respect to both the timing and capacity changes.

Typically, there are rules for how far from a sensor a wind turbine can be or how many meteorological data collection towers (met towers) are needed. However, there are no standardized data requirements for wind VERs and only CAISO currently monitors meteorological conditions for solar plants.

A common format for communicating data between wind farms and control centers, similar to Inter Control-Center Communications Protocol (ICCP), is necessary. Barriers to getting high quality data (i.e., more sensors per wind project or area and higher sampling frequency) are mostly driven by economics and relate to the installation and maintenance of sensor equipment.

System operators need measurement information such as wind speed and direction that is sufficiently accurate and proximate to enable calculation of wind farm production within a specified range of accuracy.

A CAISO study indicates that forecast accuracy is improved when several wind plants are considered together. The study also considered lowering the confidence interval of forecasts, noting that high confidence intervals (i.e. 95%) did not prove useful. ERCOT uses an alternative to the confidence interval approach, instead utilizing a minimum performance level, or exceedance, approach which sets a level at which forecasters are 80% confident the day-ahead production will exceed. It was also observed that forecast accuracy will be higher during the relatively infrequent periods of high capacity utilization and the periods of low wind generation output. Low outputs from wind generation resources generally coincide with the summer season and high ambient temperatures. These conditions correlate to high demand for most IRC markets.

Forecasting Extreme VER Ramp Events

Extreme changes in wind plant power output over short periods of time can result from air mass changes, thunderstorms, cold fronts, nocturnal stabilization, pressure changes, and other transient atmospheric events. The severity of these events is highly dependent on weather and geographic diversity of resources.

For example, ramping of any one wind farm due to a fall off in wind speed is not as dramatic an event as the loss of a major conventional plant today. However, an event that affects all the VERs in one region within a narrow time frame may be as severe as or more severe than a single conventional generator failure. When wind output drops suddenly, geographic diversity can reduce the effect of a fall-off across multiple wind farms. With the highest penetration of wind capacity in the U.S., ERCOT has also experienced the most significant wind ramp events.

A number of ISOs/RTOs have been working with researchers and forecast vendors to develop tools to better forecast wind speed variability. For example, ERCOT has implemented a ramp forecast tool which looks out six hours and alerts system operators when there is a significant probability of a large wind power output ramp.

3. Scheduling and Dispatching VERs

Historically, VERs were scheduled at, or close to, real time to avoid the cost of balancing a potentially inaccurate day-ahead commitment. Nearly all markets now incorporate VER bids into their day-ahead markets, thanks to changes in market design.

Currently, in CAISO, ISO-NE, NYISO and SPP, there is no obligation on VERs to schedule any of their capacity day-ahead. However, like conventional resources, VERs have an economic interest in scheduling at least some of their output day-ahead to hedge against real-time price volatility. Nevertheless, many VERs continue to submit bids only in the real-time market.

PJM, Midwest ISO and ERCOT currently impose day-ahead scheduling requirements on some or all VERs. In PJM, all capacity resources are required to schedule day-ahead, and this obligation includes VERs that are capacity resources. Neither Midwest ISO nor ERCOT has a capacity market, but both require some degree of day-ahead scheduling by VERs. In Midwest ISO, VERs that are designated as meeting capacity requirements are required to submit offers in the day-ahead market.

ISOs and RTOs are supportive of moving towards intra-hour scheduling across the inter-ties for purposes of VER integration where merited by system needs. Indeed,some have already implemented such scheduling. Some regions are also looking at intra-hour scheduling within the region itself. One general observation is that while market efficiencies could be achieved with more frequent inter-ISO scheduling to allow more rapid balancing of generation changes in each region, a closely coordinated process would be required to allow for such intra-hourly scheduling to achieve its desired outcomes. There will also be costs to such changes. In many cases, existing software cannot currently handle intra-hour scheduling or a substantial expansion of economic dispatch across the interties (i.e., dynamic scheduling). To the extent that certain functions are performed by control room operators and telephone communication, as opposed to software and electronic communications, there is a practical limit to the frequency with which all the necessary market and reliability functions can be performed. Costs for additional manual adjustments and software development have not yet been determined. For the purposes of financial settlement, all ISOs/RTOs treat day-ahead VER schedules the same as schedules for conventional resources. Deviations in real-time production from the day-ahead schedule are settled at real-time prices. There are some markets that do not assess day-ahead uplift charges to VERs that are scheduled day-ahead. However, these uplift charges are typically a small fraction of the financial settlements for energy deviations.

More accurate day-ahead forecasts of VER production should facilitate participation of VERs in the day-ahead market. In markets where VER capacity resources are already required to provide a day-ahead schedule, this would primarily apply to energy-only VERs. As centralized day-ahead forecasts are improved and made available for usage by the individual VER operators, there should be a corresponding improvement in their ability to support day-ahead scheduling decisions. Better tools are needed to forecast weather events and the impact of these events on the VERs' energy production over time.

4. Reliability Commitment

Since there are only two formal markets – day-ahead and real-time – in which VERs' expected output can be integrated into the market commitment and dispatch, the reliability assessment and commitments that take place in between these markets can be expected to play a larger role in system resource optimization over time.

As such, several ISOs/RTOs have begun to integrate centralized VER forecasts into the day-ahead reliability unit commitments, and have integrated a short-term wind forecast into real-time commitment and dispatch in the intra-day timeframe. ISOs such as CAISO and NYISO include forecasted wind production in evaluating whether to commit additional resources day-ahead to meet forecasted load. Several ISOs and RTOs, including CAISO, NYISO and the Midwest ISO have integrated a short-term wind forecast into real-time commitment and dispatch in the intra-day timeframe.

System operators will occasionally have to issue out-of-market or manual instructions to address system concerns that were not addressed by the day-ahead or real-time market software solutions. ISOs/RTOs have begun to report an increase in out-of-market instructions related to changes in VER forecasts; however they do not appear to be widespread at this time.

5. VERs in Real-time

One of the major advantages of ISOs/RTOs in managing renewable integration is provided by the operation of regional real-time markets that provide dispatch instructions and prices on a five- to ten-minute basis. Real-time energy markets help manage the discrepancies between day-ahead schedules and the moment-to-moment operational conditions.

The structure of the real-time markets typically provides the incentive for VERs to follow dispatch instructions – higher prices indicate a need for additional generation, while lower prices indicate a need for decreased generation. Nevertheless, several ISOs/RTOs have recently changed their redispatch and over-generation curtailment practices to reflect the impact of increasing numbers of VERs. In fact, ISOs and RTOs are moving away from manual dispatch of VERs to economic dispatch by allowing VERs to bid in day-ahead or real-time markets and by revising market rules, including bid floors, to make VERs price-responsive.

VERs are occasionally required to be dispatched down in real-time due to line limitations, an excess of generation or other system operating conditions. In addition, the appropriate negative real-time prices may induce some VER operators to take their units off-line for financial reasons.

ISOs/RTOs are moving toward putting VERs on economic dispatch. NYISO and PJM allow wind generators to bid a price, including negative prices that reflect their willingness to curtail operations if reductions in generation are required in real-time. This rule effectively treats wind generation identically to other generators, and these wind generators receive five-minute dispatch signals similar to other generators.

Because they often produce during off-peak, light load conditions, wind resources are already increasing the frequency of minimum generation or over-generation events, in some regions. However, the nature of these conditions as well as market rules and operational protocols vary among the ISOs/RTOs. In general, ISOs/RTOs initiate non-market reliability procedures to address minimum generation/over-generation events after all economic bids to decrement have been exhausted, all units are at minimum operating levels, and external transactions have been adjusted accordingly.

6. The Impact of VERs on Ancillary Services

The impacts of forecast error and the variability of supply associated with VERs have led to an examination of potential changes in the procurement and utilization of ancillary services. Current methods for managing reserves and regulation may not be sufficient to maintain reliable operations with higher levels of VER penetration.

Analysis of different ancillary service requirements for renewable integration is being conducted under both ISO/RTO and NERC initiatives. In some regions, procurement of certain types of existing ancillary services is expected to increase. There may also be an interest in the definition of new ancillary service products that correspond to new system requirements emerging from renewable integration. A load-following or VER-following reserve would be needed if VER variability and forecast error were such that these exceeded the ramp capabilities of the units committed and dispatched within the operating hour. Reserve sharing between Balancing Authorities is also a potential solution to mitigate the intermittent nature of VERs but transmission congestion at the inter-ties may prove to be an obstacle in sharing reserves. The concept of contingency reserves for extreme wind events is currently being studied by some ISOs and RTOs, including the Midwest ISO. Procurement of ancillary services currently accounts for a small percentage of total wholesale market costs – generally under five per cent – however renewable integration could lead to increases in such costs and raise policy questions about their allocation.

Some ISOs/RTOs are also actively facilitating the participation of limited energy storage devices (grid-connected batteries and flywheels), as well as demand response in the ancillary service markets.

To date, only NYISO and ERCOT have procured additional ancillary services to address the forecast uncertainty or supply variability of VERs. Operational assessments by the ISOs and RTOs and other entities, such as the NERC Integration of Variable Generation Taskforce (IVGTF), have suggested the following possible adjustments to ancillary service procurement:

- Additional procurement of regulation in the upward and downward direction, possibly on a variable basis throughout the operating day, to address the impact of VER variability on Automatic Generation Control (AGC) within the real-time dispatch interval;

- Additional reserves on a 10-minute or greater basis to account for conditions where the potential loss of VER output may eventually be greater than the single or second largest contingency on the system;
- Additional non-contingency reserves to "follow" the increased variability of load and supply resources within the operating hour, sometimes generically called "load-following." At high levels, VER variability may exceed the upward or downward ramp capability of the resources committed by the day-ahead market and subsequent reliability assessments.

ISOs/RTOs are also considering potential ancillary service enhancements to address contingencies that include extreme VER ramps, however the operational assessments conducted so far have not yet determined the need for such a product alongside the existing reserve products. The industry must continue to carefully consider the effect of high-speed cutout events on the industry's ability and cost of meeting the "one day in 10 year" standard.

At high levels of VER there is a strong possibility that system operations will require additional frequency response from some resources in order to compensate for reduced rotating mass (inertia) and governor response when conventional generation is off line. Some VER technologies are capable of providing these capabilities easily, such as concentrating solar thermal, but others are less able. Performance standards for VERS may need to be revised to require inertial and frequency response where it is technically feasible. Alternatively, additional resources may be required to provide inertial and frequency response, such as conventional units kept online for reliability purposes or new technologies such as flywheels and battery storage devices.

7. VERs and Resource Adequacy – Capacity Markets

Historically, the primary driver behind capacity markets or capacity requirements is to ensure that ISOs/RTOs are able to maintain resource adequacy requirements that are equal to the system's forecasted peak load plus a reserve margin. Capacity markets also have a secondary purpose to ensure that capacity resources are able to generate enough revenues to recover their fixed, going-forward costs of operation, including fixed investment costs. If the revenues that accrue to capacity resources from participation in energy and capacity markets are not sufficient to recover fixed, going-forward costs including investment costs, then new generating resources, regardless of type, will either not enter the market, and existing resources may retire. The latter point is important because over the long term, most production simulation studies with higher levels of VERs show substantial displacement of fossil energy by the zero-priced renewable energy, resulting in drops in energy prices and fossil generation revenues (although this price reduction could be offset by carbon pricing). Over time, this price impact could become more substantial, especially in high renewable energy states such as Texas and California.

VERs pose certain challenges for capacity markets. These markets exist to ensure resource adequacy, however wind resources have particularly poor availability during system peaks. As a result, each ISO/RTO has developed rules for participation in capacity markets that account for the ability of wind resources to respond when needed. Capacity rating of VERs has been generally done directly or indirectly based on expected performance during system peaks. However, at higher levels of VER penetration, small errors in determining capacity values can lead to insufficient dispatchable capacity resources being procured to serve peak-hour needs. This has resulted in regions using a more restrictive approach to determining capacity values for VER resources.

As VER levels increase, they will account for an increasing share of the capacity requirement, even at low capacity factors. It is also important to recognize that linkages already exist between the received energy and ancillary services revenues and the going forward value of capacity. Some ISOs and RTOs are currently looking at whether the existing product portfolio of capacity, operating reserves, and imbalance energy is sufficient to ensure reliable grid operation or whether additional reserve products will be needed.

8. Balancing Authority Coordination

Smaller Balancing Authorities will typically face higher VER integration costs as compared to larger Balancing Authorities. This is due to the limited number of resources available to provide ramp and additional ancillary services, and the absence of a reduction in variability associated with a larger-area geographical aggregation of VERs. Even larger Balancing Authorities may need to coordinate with each other as VER penetration increases, as evidenced by recent efforts by CAISO and the Bonneville Power Administration to evaluate regional integration requirements.

ISOs/RTOs are evaluating and introducing new or improved tools and arrangements to improve operational coordination among balancing authorities, including market-to-market coordination and coordination between ISOs/RTOs and regions without electricity markets. These tools and arrangements are particularly important for ISOs/RTOs that expect substantial renewable imports to meet state renewable portfolio standard requirements, such as CAISO.

With the exception of the Midwest ISO and PJM, all ISOs/RTOs currently schedule inter-ties at one-hour intervals. Shorter scheduling intervals would increase the inter-area scheduling, thereby increasing the flexibility of the system and accommodation of VERs. Other ISOs and RTOs are looking at into this while keeping the cost-benefit aspect in mind.

ISOs/RTOs support moving towards intra-hour scheduling across the inter-ties for purposes of VER integration where warranted by system needs. Indeed, some have already implemented such scheduling. While market efficiencies could be achieved with more frequent inter-ISO scheduling to allow more rapid balancing of generation changes in each region, a closely coordinated process would be needed.

While there is clearly a cost associated with such changes, the benefits would become more significant at higher VER penetration. Where there are transmission constraints that would allow VERs to be more efficiently integrated through a more closely coordinated dispatch with a neighboring market, such changes would be beneficial.

9. Conclusion

Integrating renewable resources is challenging due to the intermittent nature of the fuel source. However ISOs and RTOs are working towards meeting these challenges by developing and implementing tools such as forecasting methodologies and services such as incorporating VERs into the bidding and dispatch process and developing additional product offerings in the ancillary services markets which will help integrate these resources effectively and efficiently into both system operations and wholesale markets.

10. Acronyms

AESO	Alberta Electric System Operator
AGC	automatic generation control
ATC	Available Transfer Capability
AWEA	American Wind Energy Association
BA	Balancing Authority
BAA	Balancing Authority Area
BPA	Bonneville Power Administration
CAISO	California Independent System Operator
CREZ	Competitive Renewable Energy Zones
EIA	Energy Information Agency
ERCOT	Electric Reliability Council of Texas
FCM	forward capacity market
FERC	Federal Energy Regulatory Commission
IESO	Independent Electricity System Operator (Ontario)
ISO-NE	Independent System Operator of New England
ISO	Independent System Operator
IVGTF	Integration of Variable Generation Task Force (NERC)
LSE	load-serving entity
Midwest ISO	Midwest Independent System Operator
MW	megawatt
MWh	megawatt-hour of energy
NBSO	New Brunswick System Operator
NERC	North American Electric Reliability Council
NPCC	Northeast Power Coordinating Council
NYISO	New York Independent System Operator
PIRP	Participating Intermittent Resource Program (California ISO)
PJM	PJM Interconnection, L.L.C.
PSC	Public Service Commission
PUC	Public Utility Commission
REC	Renewable Energy Credit
RA	Resource Adequacy
RTO	Regional Transmission Organization
RPS	Renewable Portfolio Standard
SCE	Southern California Edison
SPP	Southwest Power Pool
WECC	Western Electricity Coordinating Council

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