NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

California ISO
Shaping a Renewed Future

2013 Special Reliability Assessment:

Maintaining Bulk Power System Reliability While Integrating Variable Energy Resources – CAISO Approach

A joint report produced by:

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and

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RELIABILITY | ACCOUNTABILITY



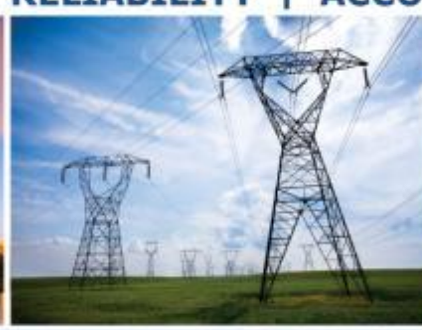



Table of Contents

Executive Summary 1
Chapter 1 – California Initiatives and Power Market Impacts 6
Chapter 2 – Operational Challenges 13
Chapter 3 – Reactive Power Control and Voltage Regulation at the Interconnection Point 20
Chapter 4 – Distributed Energy Resources (DERs) 23
Chapter 5 – Steady-State, Short-Circuit, and Dynamic Generic Model Development of Variable Resources........ 25
Chapter 6 – Current Forecasting Ability and Future Needs 27
Chapter 7 – Operating Tools.. 33
Chapter 8 – CAISO Market Enhancements 39
Chapter 9 – Conclusions 44
Appendix 1: About the NERC-CAISO Joint Report 45
Appendix 2: References 50

Executive Summary

Integrating large quantities of variable energy resources (VERs) (predominantly wind and photovoltaic (PV) solar) into the North American bulk power system (BPS) requires significant changes to electricity system planning and operations to ensure continued reliability of the grid. The purpose of this report is to focus on considerations that all system planners and operators must address to reliably integrate significant quantities of VERs into the BPS. This report highlights the California Independent System Operator Corporation's (CAISO) current efforts to address these challenges as the issues are imminent in CAISO's area of operation.

Reliable operation of the grid requires that essential reliability services be present:

- **Inertia** – The stored rotating energy in a power system provided by synchronous and induction generation.
- **Frequency Response** – The automatic corrective response of the system, typically provided by synchronous generation for balancing demand and supply.
- **Regulation** – A service that corrects for short-term fluctuations in electricity use that might affect the stability of the power system.
- **Load-Following** – The ability to adjust power output as demand for electricity ramps throughout the day.
- **Active Power Control** – The ability to control power output of a given electric resource.
- **Reactive Power and Voltage Control** – The ability to control the production and absorption of reactive power for the purposes of maintaining desired voltages and optimizing transmission and generation real-power losses.
- **Disturbance Ride-Through Tolerance** – The ability of a resource to remain connected through a system disturbance, such as a large frequency excursion.
- **Steady-State and Dynamic Stability Modeling** – The complex power-flow analyses that provide insight into the expected behavior of a power system during normal conditions; also provides insight into systems subjected to disturbances.
- **Load and Generation Forecasting** – The tools used to predict demand and nondispatchable resources in a variety of time frames ranging in time period from real time to several decades.

Electricity supply traditionally has been provided by fossil-fueled, large-scale hydro and nuclear resources synchronously connected to the grid. Industry has established reliability expectations with these generating technologies through knowledge accumulated over many years of experience. These traditional generation resources have predictable operating performance with well-understood reliability characteristics.

VERs have different characteristics and respond differently on the system. System operators have much less knowledge and experience with such resources on a large scale. As larger amounts of variable generation are added to the system, they will displace the traditional large, rotating machines and the operating characteristics those machines provided.

NERC began to address these issues with the creation of the Integration of Variable Generation Task Force (IVGTF) in December 2007 and the publication of a summary report, *Accommodating High Levels of Variable Generation*, in April 2009. Additional studies and reports from the task force include:

- *Variable Generation Power Forecasting for Operations* (May 2010)
- *Standard Model for Variable Generation* (May 2010)
- *Flexibility Requirements and Potential Metrics for Variable Generation* (August 2010)
- *Potential Reliability Impacts of Emerging Flexible Resources* (November 2010)
- *Operating Practices, Procedures, and Tools* (March 2011)
- *Ancillary Service and Balancing Authority Area Solutions to Integrate Variable Generation* (March 2011)
- *Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning* (March 2011)
- *Potential Bulk System Reliability Impacts of Distributed Resources* (August 2011)
- *Interconnection Requirements for Variable Generation* (September 2012)

References to these reports can be found in Appendix 2 of this report.

NERC's *2013 Summer Assessment* recognized the growing presence of wind and solar resources as a North American issue:

> Operationally, an increase in wind and solar resources continues to challenge operators with the inherent swings, or ramps, in power output. In certain areas where large concentrations of wind resources have been added, system planners accommodate added variability by increasing the amount of available regulating reserves and potentially carrying additional operating reserves. Because weather plays a key factor in determining wind and solar output, enhancing regional wind and solar forecasting systems can provide more accurate generation projections. Other methods include curtailment and limitation procedures used when generation exceeds the available regulating resources. In this respect, operating criteria, forecasting, commitment, scheduling, dispatch and balancing practices, procedures, and tools must be enhanced to assist operators in maintaining BPS reliability.

From the *2012 Summer Assessment*:

> Variable resources—especially wind—are growing in capacity and becoming an important portion of the generation mix in many areas of North America. It is vital to ensure that these variable resources are reliably integrated into the bulk power system and that both planning and operational challenges are addressed.

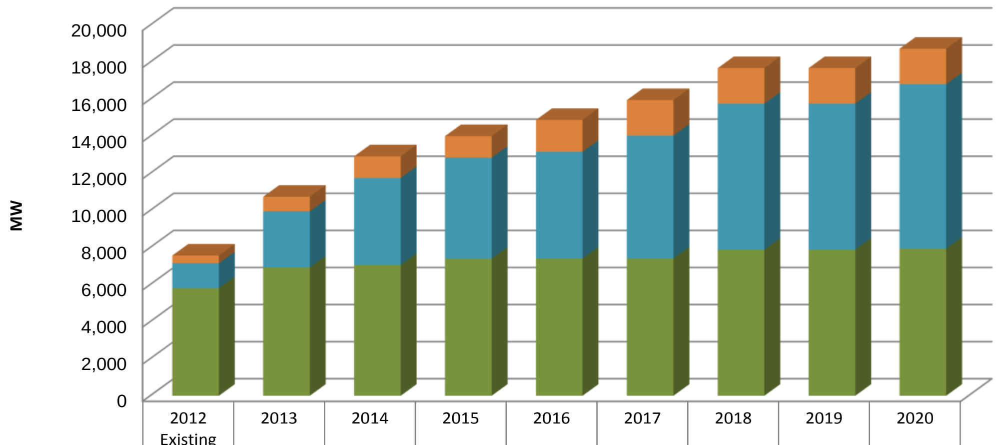
The new challenges presented by renewable resource additions were a key reliability finding in NERC's *2012 Long-Term Reliability Assessment*:

> Renewable resources are growing in importance in many areas of North America as the number of new facilities continues to increase. The share of capacity from renewable resources will continue to grow, especially as significant additions are projected for both wind and solar throughout North America. In 2012, renewable generation, including hydro, made up 15.6 percent of all on-peak capacity resources and is expected to reach almost 17 percent in 2022. Contributing to this growth is approximately 20 GW of on-peak Future-Planned capacity and an additional 21.5 GW of on-peak Conceptual capacity. It is vital that these variable resources are integrated reliably and in a way that supports the continued performance of the BPS and addresses both planning and operational challenges.

Addressing the Unique Challenges in California

California recently raised its renewable portfolio target for utilities to 33 percent by 2020. Potential operating challenges presented by a 33-percent mix of renewables will make it difficult for the system operator to balance supply and demand in real time unless there are changes to existing practices.

The electricity supply mix in California is distinctly different from that of other states or regions of the country and is projected to significantly change in the long term. By 2020, an additional 11,000 MW of VERs are expected to be connected to the CAISO grid, which is anticipated to add to the uncertainty and variability of the future resource mix. As this report will explain, CAISO projects that more flexibility in accessing essential reliability services will be needed to reliably meet net load, manage approximately 3,000 MW of intrahour load-following needs, and provide nearly 13,000 MW of continuous up-ramping capability within a three-hour time period.



	2012 Existing	2013	2014	2015	2016	2017	2018	2019	2020
Solar Thermal	419	792	1,167	1,167	1,717	1,917	1,917	1,917	1,917
Solar PV	1,345	3,022	4,693	5,445	5,756	6,628	7,881	7,881	8,872
Wind	5,800	6,922	7,058	7,396	7,406	7,406	7,877	7,877	7,934

Figure I: California Planned VER Additions to Meet 33% Renewables Portfolio Standard (2013–2020)

CAISO is addressing the challenges presented by the integration of large amounts of variable generation. This report describes their challenges and details the steps CAISO is taking or recommending to address the challenges.

CAISO's current efforts to integrate VERs provide a good case study for others who will need to address these matters in the coming years. NERC endorses CAISO's engagement in spearheading efforts to address an important shift in planning and operations.

Conclusions and Recommendations

Forecasted high levels of VERs in CAISO are becoming a reality, and this report identifies the key system enhancements in planning and operations that are needed to promote reliable operations and maintain essential reliability services. The CAISO initiatives in this report reflect the recommendations originally developed by NERC's IVGTF and approved by NERC's Planning and Operating Committee.

NERC expects the solution set to include some mix of market approaches, technology enhancements, and reliability rules or other regulatory rule changes, and that the solution set will likely be different in various parts of North America. Regulators will be called on to make appropriate adjustments to market rules and tariffs. To the extent that NERC Reliability Standards are considered to address these issues, standards must be technology-neutral.

At a high level, the report concludes that as an electric system approaches a significant penetration in variable resources:

- Essential reliability services will be strained;
- Technical aspects of the evolving resource mix must be given due consideration at state, federal, and provincial levels;
- Solution sets for maintaining reliability can come from:
  - Market tools and rules,
  - New technology integration, and
  - Standards or requirements; and
- Unresolved cost implications can impede solution sets.

In summary, NERC recommends the following:

- NERC, state and provincial regulators, and industry should use an analytical basis for understanding potential reliability impacts as a result of increasing VERs and how those impacts can affect system configuration, composition, and essential reliability services.
- Based on analytical results and the broad experience of NERC stakeholders, specific recommendations for changes to operating and planning practices, state and provincial programs, and pertinent NERC Reliability Standards should be developed. Specific recommendations to date are provided in the NERC IVGTF reports listed in Appendix 2.
- VER issues can be addressed through many non-NERC avenues (e.g., market rules; vertically integrated operations; or federal, state, and provincial programs). However, it is recommended that NERC work with affected entities in the different NERC Regions, including state and provincial agencies that have jurisdiction over VERs, wholesale market areas, and vertically integrated utilities, to develop appropriate guidelines, practices, and requirements to address VER integration issues that impact the reliability of the BPS.

CAISO recommendations are included throughout the report and are specific to the CAISO area. While these recommendations represent good industry practice in meeting reliability objectives, consideration of region-specific issues and tailored approaches will likely be needed as other areas observe increasing VER trends.

Specific items for consideration include:

- **Reactive Power Control:** Requirements for asynchronous generating facilities to provide reactive support should be considered for adoption. Applying a uniform reactive power standard would help eliminate situations in which projects interconnecting later in time may need to wait for additional reactive power resources to compensate for unstable voltage conditions on the grid. Additionally, uniform requirements promote enhanced grid reliability and ensure all generation supports the interconnection's reliability needs.

- **Active Power Control:** NERC's findings show that with large amounts of VERs, active power control may be needed to maintain reliability. VERs should have the capability to receive and respond to automated dispatch instructions as well as maintain an ability to limit active power output, should there be a reliability need.

  Plants should be designed with consideration of more flexible ramp rate limit requirements. Requirements for certain operating conditions could possibly be removed. Variable generation plants should not be required to limit power decreases due to declines in wind speed or solar irradiation (i.e., down-ramp rate limits). However, limits on decreases in power output due to other reasons, including curtailment commands, shut-down sequences, and responses to market conditions, can be reasonably required. In addition, when a fuel source returns, VERs should have the capability to ramp up in controlled increments.

- **Inertia and Frequency Response:** NERC's findings show that with large amounts of certain types of VERs—particularly solar PV—a potential decrease of system inertia and frequency response could result in reliability impacts on the BPS. To resolve this emerging trend, CAISO is recommending that all generation resources have the capability at the plant or interconnection level to contribute to the inertial and frequency response needs of the system. While this is one approach, all resources should have the ability to automatically reduce energy output in response to high system frequency. Variable generation plants should be encouraged to provide overfrequency droop response of similar character to that of other synchronous machine governors.

- **Steady-State, Short-Circuit, and Dynamic Generic Model Development**: NERC's findings show that with large amounts of VERs, modeling smaller generator units with often unknown proprietary control models can manifest into large modeling errors and an incorrect understanding of system behavior. Standard, valid, generic, nonconfidential, and public power-flow (steady-state) and stability (dynamic) models for VERs are needed and must be developed to enable accurate system representation.

Chapter 1 – California Initiatives and Power Market Impacts

California's renewables portfolio standard (RPS) mandates that utilities serve 20 percent of all retail load from eligible renewable resources between 2011 and 2013.[1] This portfolio increases to 25 percent from 2014 to 2016 and reaches 33 percent by 2020. A portion of the RPS would be satisfied by VERs on the distribution system behind the customer meter, which is a challenge to forecast without planning visibility and operating observability. Changes in subhourly load are typically driven by variations in customer demand. However, the large expected increases in VERs—particularly those interconnected to the distribution system—will drive more subhourly load variability and cause large and steep ramps to occur several times a day.

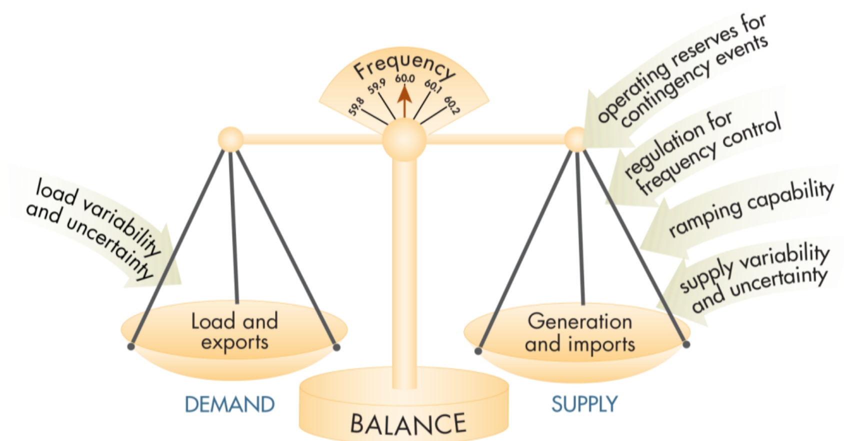


Figure 2: Continuous Supply and Demand Balance

1.1 CAISO Real-Time Market Overview

The CAISO markets consist of a day-ahead market and a real-time market. The day-ahead market includes an integrated forward market used to clear supply-and-demand bids and a residual unit commitment to ensure that sufficient capacity is committed to meet CAISO forecast demand. The real-time market includes the hour-ahead scheduling process used to arrange hourly intertie transactions, the short-term unit commitment used to commit resources looking five hours ahead, the real-time unit commitment used to commit resources and procure ancillary services every 15 minutes, and a real-time economic dispatch every five minutes. CAISO conducts an intrahour dispatch every five minutes through its real-time market applications. After the day-ahead market closes (at 10:00 a.m. the day prior to the operating day), CAISO relies on several processes and software applications to manage supply-and-demand balance.

To better manage transmission constraints, congestion management ensures efficient and feasible supply-and-demand decisions. In support of congestion management, CAISO employs a full network model that accurately represents the CAISO Balancing Authority (BA) and calculates locational market prices to settle the transactions. The security-constrained unit commitment is utilized in the day-ahead market and real-time market to commit units, and security-constrained economic dispatch is used to balance the system generation, demand, and import and export schedules while respecting transmission constraints. In real time, real-time economic dispatch is used to generate five-minute dispatches to meet imbalance energy requirements.

[1] http://www.cpuc.ca.gov/NR/rdonlyres/2060A18B-CB42-4B4B-A426-E3BDC01BDCA2/0/2012_Q1Q2_RPSReport.pdf

The objective of a real-time market is system balancing on a forward-looking basis on a five-minute interval above and beyond the normal function of automatic generation control (AGC), which is done every four seconds. The real-time market's AGC is more a control than an energy service. As AGC units depart from their dispatch operating targets as established by the real-time market five-minute dispatch application,[2] they temporarily supply or consume balancing energy.

CAISO procures ancillary services regulation, spinning reserve, and nonspinning reserve as part of the simultaneous energy and ancillary services optimization. The ancillary service capacity is mostly procured in the day-ahead market with some incremental procurement in real time to account for changes in operating conditions. Spinning reserve and nonspinning reserve capacity is converted to energy as necessary following a contingency event. However, CAISO may also economically dispatch excess spinning and nonspinning capacity if the market participant identified that such capacity can be dispatched to energy regardless of a contingency event.

In addition, CAISO recently introduced a flexibility constraint[3] into its real-time market optimization to better ensure that sufficient resource capability is committed that can address noncontingency-event-related changes in load and supply. The flexibility constraint is currently enforced only in the real-time unit commitment and dispatch process. CAISO and stakeholders are now considering changes that would make flexibility a market product that is procured in both day-ahead and real-time markets.

1.2 Renewable Generation Impacts in the CAISO Real-Time Market

Dispatched resources are expected to move to their new operating target every five minutes, while resources not receiving a dispatch instruction are expected to remain at their target (as they were not instructed to move). VERs such as wind and solar generation contribute to uninstructed deviation (i.e., negative flexibility) because their production levels can change significantly within five-minute dispatch intervals.

Wind generation resources typically submit their hourly forecasted output as schedules in the real-time market 105 minutes before the operating hour. While these schedules represent the forecast production 105 minutes before the hour, the schedules do not represent the actual energy produced because wind generation output frequently and significantly changes. Predispatch practices used for conventional resources cannot effectively accommodate the variability of wind and solar generation according to hourly schedules because of potentially limited capabilities (i.e., fast ramping capabilities). This becomes more challenging as wind and solar products increase beyond the 20 percent RPS milestone. It creates a potential need for increased regulation reserve. For the next dispatch interval, CAISO will use a persistent dispatch mechanism and is in the process of integrating a 15-minute forecast to be used explicitly for predicting future wind and solar production.

Existing real-time market applications cannot predict and use the deviations from VER forecasts, although deviations will be minimized when the real-time variable forecasts are integrated into the real-time market software applications. This variability could cause short-term ramping shortages that result in dynamic market prices and fluctuating dispatch instructions to units in the real-time supplemental energy market.

[2] In response to frequency and net interchange deviations.

[3] Flexibility constraint is necessary to address certain reliability and operational issues observed in CAISO's grid operation. CAISO has observed at times that reserves and regulation service procured in real time and units committed for energy in the 15-minute unit commitment process lack sufficient ramping capability and flexibility to meet conditions in the five-minute market interval, during which conditions may have changed from the assumptions made during the prior procurement procedures. Under the flexible ramping constraint, unit commitment and dispatch will ensure the availability of a prespecified quantity of upward five-minute dispatch capability. This capability is provided by committed flexible resources not designated to provide regulation or contingency reserves and whose upward capacity is not committed for load forecast needs.

To facilitate renewable resources' participation in its markets, CAISO has developed the participating intermittent resource program (PIRP). The program provides a centralized wind and solar power production forecast to its participants on a daily and hourly basis. In the real-time market, the PIRP resources must submit hourly self-schedules to match the projected values populated by the program's forecasting service. Monthly deviations of the actual delivery of energy from the scheduled energy are settled based on the monthly real-time imbalance energy prices. Renewable resources are also allowed to bid into the energy markets if they choose, but this precludes participation in the PIRP for the bidding period.

1.3 Load-Following Flexibility Requirement

The uncontrolled but relatively predictable output of VERs often results in large intraday ramps. As more VERs are added to the electric system, steeper ramps are likely and therefore require flexible resources that can follow those steep ramps. Two key components are required to ensure net load can be met: an accurate forecast and a resource pool with the capability to provide flexible, fast-acting response. As highlighted and recommended in a NERC IVGTF report,[4] enhanced planning and operational tools are needed to understand long-term and operation flexibility requirements.

A major CAISO operational and market function is to forecast system load and VER production in the day-ahead and real-time time frames. A good forecast ensures sufficient conventional resources are committed such that intrahourly deviations from hourly schedules can be accommodated by resources under dispatch control. These deviations can take place in the upward or downward direction. Figure 3 illustrates the hourly load-following or flexibility requirement as the blue shaded area.[5] For the purposes of performing a fleet assessment, CAISO has calculated the amount of load-following based on the difference between the hourly average net load and the five-minute net load. In real-time operation, CAISO intends to use a load-following requirement tool to calculate the hourly load-following capacity and ramping requirements, which supports the NERC IVGTF recommendation.

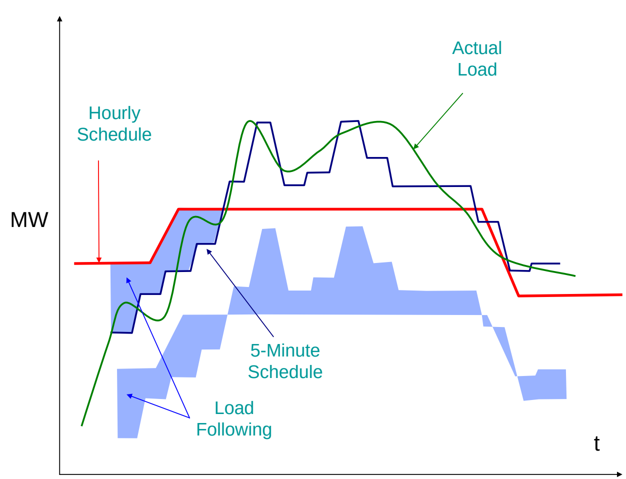


Figure 3: Load-Following or Flexibility Requirement (shown as the blue shaded area)

[4] NERC: *Flexibility Requirements and Potential Metrics for Variable Generation: Implications for System Planning Studies*: http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/IVGTF_Task_1_4_Final.pdf

[5] CAISO: Integration of Renewable Resources: http://www.caiso.com/Documents/Integration-RenewableResourcesReport.pdf

1.4 Regulation Requirement

The output of VERs—solar PV resources in particular—can drastically change within a matter of minutes. Cloud cover drives this variability; however, geographic diversity of solar PV helps smooth the aggregated power output. Nonetheless, minute-to-minute variability of net load resulting from a larger solar PV resource base may increase regulation requirements to support essential reliability services. Future regulation requirements must be planned well in advance, as some electric systems may not have the physical capability to meet those requirements. Some loads are also well suited for providing regulation (e.g., aluminum smelters and other fast-acting demand response programs), and it is anticipated that storage may also eventually contribute in a meaningful way.

CAISO maintains sufficient generating capacity under AGC[6] to continuously balance its generation and interchange schedules with its real-time load. Generating capacity under AGC is referred to as "regulating reserve." Separate amounts of upward and downward regulation reserves are procured. The Western Electric Coordinating Council (WECC) does not specify a regulating margin based on load levels but requires adherence to NERC's control performance criteria. To meet this criteria (CPS1[7] and CPS2[8]), CAISO typically procures hourly regulating reserve in the day-ahead market for the next operating day.

Instead of dispatching regulation reserve based on energy bid curve price, CAISO dispatches it automatically through AGC every four seconds. Regulation is based wholly on the resource's effectiveness to maintain system-scheduled frequency and maintain scheduled flows between Balancing Authorities (BAs), while taking into consideration the resource's operating constraints.

Deviations within the five-minute dispatch time interval are balanced through regulation reserve dispatched by AGC. It is crucial to ensure that the units on AGC go back to their market-determined set points.

If available regulation is insufficient, CAISO may request additional assistance from the interconnection. Such assistance can be measured in real time through Area Control Error (ACE) and through accumulated inadvertent interchange over a longer period.

To the extent a resource is moved away from its market real-time dispatch (RTD)-based set point (five-minute imbalance market)—which AGC calls "dispatched operating target"—the market-clearing software assumes that the resource would be brought back to its target in the next market interval. Although the regulation dispatch is done every four seconds, the regulation margin must be adequate to meet deviations within a five-minute dispatch interval as illustrated in the red shaded area in Figure 4. CAISO intends to use a Regulation Prediction Tool to determine the upward and downward regulation requirements in terms of capacity, ramp rate, and ramp duration for each operating hour for the next operating day. Refer to Chapter 7 for a description of this tool.

[6] WECC defines AGC as equipment that automatically adjusts a BA's generation from a central location to maintain its interchange schedule plus frequency bias.

[7] CPS1 is a statistical measure of ACE variability in combination with interconnection frequency error.

[8] CPS2 is a statistical measure of ACE magnitude and is designed to limit a BA's unscheduled power flow. CPS2 is currently being waived for all BAs participating in the NERC Balancing Authority ACE Limit (BAAL) field trial.

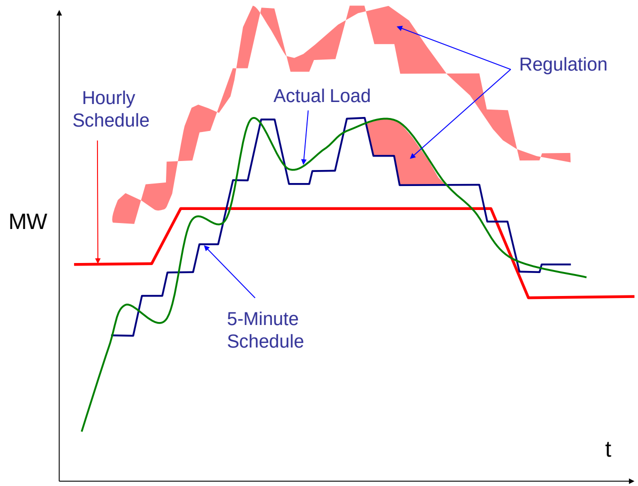


Figure 4: Regulation Requirement (shown as the red shaded area)

1.5 Fundamental Sources of Overgeneration Problems

Overgeneration occurs when there are more internal generation and imports into a Balancing Area than load and exports. Typically, before an overgeneration event occurs, the system operator will exhaust all efforts to send dispatchable resources to their minimum operating levels and will use all the decremental energy bids available in the imbalance energy market. Via the real-time unit commitment, CAISO may also decommit resources. The system operators will also make arrangements to sell excess energy out of market if bids to balance the system are exhausted. Additionally, with a high ACE, the energy management system will dispatch regulation resources to the bottom of their operating range.

When expecting overgeneration, the system operator sends out a market notice and requests scheduling coordinators to provide more decremental energy bids. If no decremental energy bids are received (or insufficient ones are received), the system operator may declare an overgeneration condition if it can no longer control the ACE and the associated high system frequency. During overgeneration conditions, the typical real-time imbalance energy price is negative, meaning that CAISO will pay entities to take their excess power. There are compelling reliability and market reasons to avoid overgeneration situations.

Currently, the capacity of nondispatchable resources serving load within the CAISO Balancing Area varies between 12,000 MW and 14,000 MW based on the maximum capability of the resources within each category. CAISO plans on exploring ways to incentivize Qualifying Capacity (QFs)[9] to curtail production during low net load demand periods in order to minimize the magnitude of potential overgeneration. CAISO also plans on partnering with storage and incenting load shifting during the hours of low net load demand. Nondispatchable capacity can be significantly higher in years with high rainfall or snowpack, especially during the spring months, when temperatures are high and can result in early snow melt and hydro spill conditions. During these operating conditions, hydro resources tend to operate close to their maximum capability to maximize production.

[9] Qualifying facilities (QFs) are a combination of qualifying small power production facilities and qualifying cogeneration facilities. The three QF categories shown in Figure 4 were broken down by fuel type; gas-fired QFs, geothermal, and other QFs (powered by renewables such as biogas, biomass, waste and oil). Cogeneration facilities are typically the larger QFs that sequentially produce electricity and another form of useful thermal energy (such as heat or steam) in a way that is more efficient than the separate production of both forms of energy.

To avoid negative energy prices and high ACE, a seasonal overgeneration assessment that includes medium-term generation predictions is needed. The assessment should take into account system topology, operating conditions, and constraints. Figure 5 shows the potential for CAISO's net load (load minus wind and solar production) to drop below the total production level of nondispatchable resources on the system, which can occur on low system demand days, such as weekends. The areas labeled "Load-Following Down" and "Regulation Down" can only be obtained by operating dispatchable resources above their minimum operating levels in order to have downward control to compensate for increases in wind and solar production within an operating hour. The potential to export excess generation to neighboring BAs during low system demand periods may be feasible but impractical, because other BAs may need to keep a portion of their dispatchable resources on-line to meet load changes and comply with mandatory control performance standards.

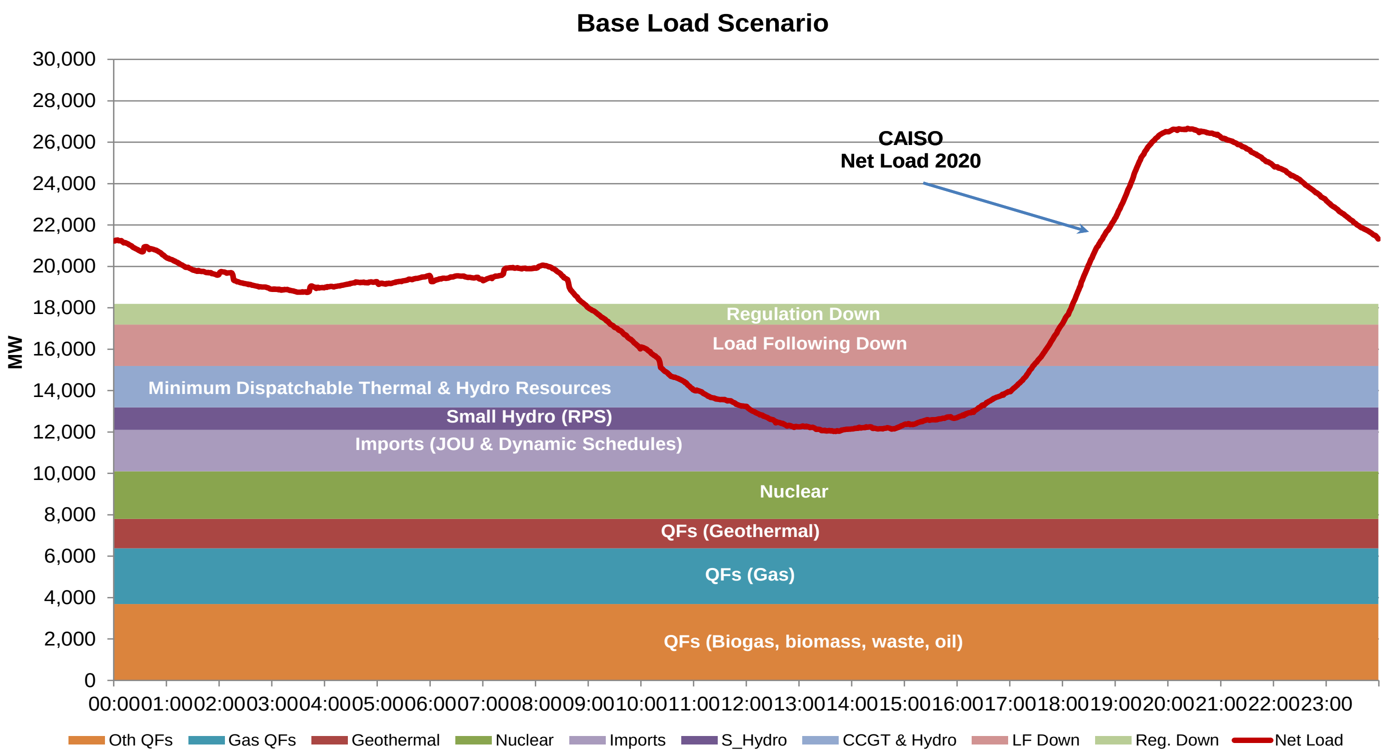


Figure 5: Potential Overgeneration Conditions – March 2020

Sources of overgeneration are noted in Table 1.

Table 1: Sources of Overgeneration and Mitigation Measures

#	Sources	Mitigation
1	Mismatch between scheduled generation and actual production	Develop a mechanism to update the schedules of variable resources on a five-minute basis for a look-ahead of two hours.
2	More “must-take” generation (combined with other local generation at minimum) than there is system load	Develop operating procedures to curtail “must-take” generation and/or develop incentives for these resources to curtail production.
3	Forecast errors (both for day-ahead and hour-ahead load and for wind and solar energy production)	Develop an optimized forecast for different time horizons.
4	Hourly scheduled imports are fixed during the operating hour regardless of changing system conditions intrahour; e.g., load decreases or VER increases	Introduce intrahour tagging and scheduling; e.g., 15-minute scheduling.
5	Hydro generation running at full operating capacity because of rapid snow melt in the mountains (the water must be released from the reservoirs as must-run generation or the operator will have to spill the water)	Develop operating procedures to effectively and equitably curtail must-run generation and/or developing incentives for these resources to curtail production
6	Distributed energy resources (DER) that are invisible to CAISO creating overgeneration condition when they offset load on the distribution system	Require visibility of DER.
7	Insufficient DEC bids for VERs	Lower bid floor to provide incentives. Apply negative prices to all generation not at verified minimum output.

Without mitigation or management of the sources of overgeneration (see Table 1), system reliability issues can manifest. Table 2 provides a summary of typical control problems caused by overgeneration and potential mitigation measures for use in operational planning.

Table 2: Typical Overgeneration Problems and Mitigation Measures

	Problems	Mitigation
1	System frequency higher than 60 Hz	Modify existing operating procedures to effectively and equitably curtail generation, including renewable resources, as a last resort.
2	Negative real-time energy market prices (CAISO must pay internal or external entities to consume more or produce less power)	Ensure enough flexible resources are committed and available to provide load-following down requirements or ensure that they can be shut down quickly. Apply negative prices to all generation (including VER) that is not at verifiable minimum.
3	Higher-than-normal ACE that results in reliability issues, which may result in monetary penalty	See #2.
4	Grid operators having difficulties balancing load and generation in real time because of insufficient flexible capacity	Conduct technical studies to determine the optimal flexibility needs of the fleet, including storage.
5	Disconnecting conventional generation from the grid can reduce the system’s ability to quickly arrest frequency decline following a disturbance	See #1. Also, develop advanced situation awareness tools using data from phasor-measurement units to detect and alert operators of impending problems in real time.
6	Inability to shut down a resource because it would not have the ability to restart in time to meet system peak	Explore the possibility of committing flexible resources that can be cycled on and off two or more times a day.

Chapter 2 – Operational Challenges

Improved operating practices, procedures, and tools are critical for accommodating large amounts of VERs into any power system and improving the control performance and reliability characteristics of the power system as a whole. System resources supporting reliability, such as flexible generation and responsive load, are finite. Operating practices, procedures, and tools that maximize the effective use of limited responsive resources improve reliability and facilitate variable generation integration. Operational tools can also help support and maintain the system's essential reliability services.

Generation variability over different periods (seconds, minutes, hours) and the uncertainty associated with forecasting errors are operational characteristics of wind and solar resources. Because of uncertainty associated with wind and solar production forecasts, there is an increased need to reserve additional flexible capacity to ensure that operational requirements are met in real time. Dispatchable resources will need to be flexible to respond to operational needs. At times, the existing and planned generation fleet will likely need to operate for more hours at lower minimum operating levels and provide more frequent starts, stops, and cycling over the operating day. While gas-fired generation typically has a larger operating range, larger units are usually not as flexible, which can lead to a reduction in essential reliability services—particularly during lower-demand periods and reductions in inertia and frequency control.

The following essential reliability services are impacted by integrating large amounts of VERs. CAISO and others must address these challenges:

- Self-scheduling of resources,
- Ramping capability,
- Lower capacity factors for dispatchable generation,
- Inertia and frequency response,
- Active power control, and
- Reactive power control.

As the penetration of variable generation increases, additional system flexibility and essential reliability service requirements will also increase. This flexibility manifests itself in terms of the need for dispatchable resources to meet increased ramping, load-following, and regulation capability—this applies to both expected and unexpected net load changes. This flexibility will need to be accounted for in system planning studies to ensure system reliability. System planning and VER integration studies focus both on the reliability and economic optimization of the power system—here the emphasis is on reliability.

2.1 Self-Scheduling

Empirical analysis from CAISO's 20-percent RPS study[10] demonstrated a shortage of five minutes of net load-following capability in the downward direction when resources were self-scheduled, compared to scenarios where actual physical capabilities were offered for economic dispatch. These results were further substantiated by using a production simulation application. The 20-percent RPS study made it clear that CAISO must pursue incentives or mechanisms to reduce the level of self-scheduled resources or increase the operating flexibility of otherwise dispatchable resources. CAISO is pursuing incentives and mechanisms to either reduce the level of self-scheduled resources, or increase the operating flexibility of otherwise dispatchable resources.

[10] http://www.caiso.com/2804/2804d036401f0.pdf

2.2 Ramping Capability

System operators must rely on ramping capability to balance the less predictable energy production patterns of VERs like wind and solar resources. The underforecasting of demand and underdelivering of scheduled supply in production requires dispatching flexible resources at higher levels. The alternative case results in overforecasting delivery. System operators must accurately follow load and minimize inadvertent energy flows. This calls for ramping capacity in both speed and quantity, which is dictated by how fast and how much the production patterns of VERs change. To meet this operational challenge, system operators need enough flexible resources with sufficient ramping capability to balance the system within the operating hour. As shown in Figure 6, the typical CAISO load (blue curve) has ramps that are of small capacity and long duration. However, with high penetration of renewable resources, the net load[11] (red curve) is the trajectory conventional resources would have to follow. It is comprised of a series of ramps of significant magnitude and shorter duration. It should also be noted that neither wind nor solar peak production coincides with the system peak load.

Also, to meet the double peak shown, CAISO may have to cycle resources on and off more than once a day. At times this may not be an option, because the down time between shut-down and start-up of a resource may be too long, which would prevent the resource from being restarted in time for system peak.

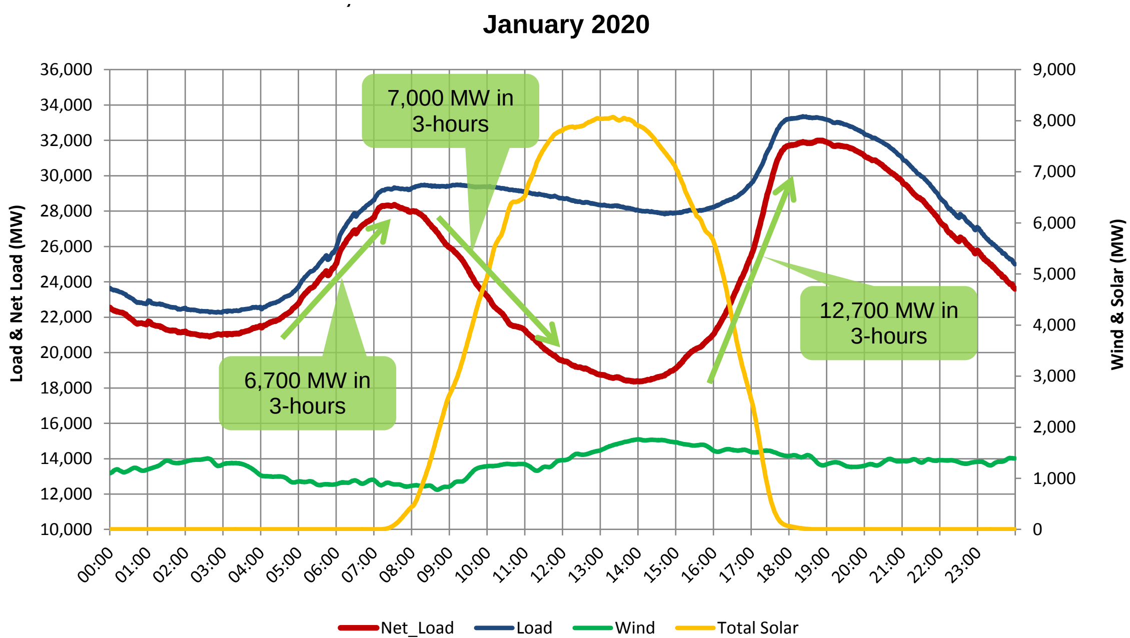


Figure 6: Load, Wind, and Solar Profiles – Base Scenario

CAISO has identified the need for flexible resources that are committed with sufficient ramping capability to balance the system within the operating hour and between hours for scheduled interchange ramps. To help manage this challenge, CAISO is implementing a ramping tool to predict and alert system operators of the load-following capacity and ramping requirements needed on the system in real time. CAISO is also introducing a flexible ramp product to ensure enough dispatchable capacity will be available on a five-minute dispatch basis in the real-time market.

[11] Net Load = Load minus Wind minus Solar

2.3 Lower Capacity Factors for Dispatchable Generation

The increased supply variability associated with a significant penetration of variable resources will cause more frequent dispatches and the starting and stopping of flexible, gas-fired generators, which will potentially incur more wear and tear. Lower-capacity factors for dispatchable generation combined with potential reduced energy prices also result in decreased energy market revenues for the gas-fired fleet in all hours and seasons. This condition raises concerns regarding revenue adequacy, as well as challenges in supporting gas-fired generation resources that are necessary for dispatch flexibility and reliability. Through technical studies, CAISO has determined that gas-fired generators will be operated at lower capacity factors and will experience more frequent start–stop and cycling instructions that could increase wear and tear on these units. Consequently, increased wear and tear can reduce mean time to failure on generation components and potentially lead to increased forced outage rates, which ultimately results in a need for additional ancillary services.

2.4 Inertia and Frequency Response

One of the reliability concerns presented by higher percentages of VERs is the displacement of resources that have the ability to arrest and stabilize system frequency following a grid disturbance or the sudden loss of a large generation source. PV solar generation offers no inertia and no frequency response, and wind generation offers virtually none unless specifically designed to do so. While VERs are able to displace energy requirements—and capacity to a lesser extent—other essential reliability services traditionally provided by conventional generation must also be replaced.

To better understand the impact from variable resources, CAISO and General Electric International, Inc. jointly conducted a frequency response study[12] to investigate the large loss of generation events targeted by NERC Standard BAL-003 – Frequency Response and Bias, under near-future system conditions with high wind and solar generation levels. While this study addresses the issue of overall Western Interconnection frequency response, it does not address the expected issues relative to changes in transfer capacities of stability-limited transmission paths that may be warranted at higher VER penetration.

Costs for subeconomic operations and the allocation of those costs to meet frequency response requirements were not quantified. The study conclusions, potential solutions, and future plans are shown in Table 3.

During periods of light load and high renewable production, the CAISO system may require subeconomic operation to meet frequency response obligations (as proposed under BAL-003-1).[13] Additionally, decreased inertia of connected generation may impact economic operation as a result of lower import capabilities. From a reliability perspective, curtailments of generation without inertial capability may be needed during these periods; however, in California, these operational procedures to maintain reliability can lead to conflicting objectives in meeting RPS.

Compared to conventional generation, VERs are less effective in providing the system with sufficient inertia to arrest frequency decline. Similarly, VERs may not create adequate governor-like response to stabilize system frequency following the loss of a large generator. Frequency excursions caused by overgeneration are possible during periods of high VER production and low system demand. If dispatchable resources are already operating at minimum load levels and regulation down capacity has been exhausted, higher-than-scheduled or higher-than-expected VER production levels can result in overgeneration and, ultimately, overfrequency conditions.

[12] CAISO/GE Frequency Response study can be found at http://www.caiso.com/Documents/Report-FrequencyResponseStudy.pdf

[13] BAL-003-1: Frequency Response and Frequency Bias Setting: http://www.nerc.com/pa/Stand/Project%20200712%20Frequency%20Response%20DL/BAL-003-1_clean_031213.pdf

Many double-fed and full-conversion wind turbines can adjust power output in real time, in response to variations in grid frequency.[14]

Table 3: Study Challenges and Potential Mitigation Plans

	Challenge Identified	CAISO Addressed	Potential Solutions/Future Plans
1	Ensure sufficient flexibility is maintained on governor responsive resources.	Monitor frequency response performance of CAISO after sudden loss of major generators in the Western Interconnection.	• Continue participating in NERC's development of a frequency response Reliability Standard. • Develop tools to track available headroom on governor responsive resource in real time. • Work with industry to develop a real-time tool to determine the adequacy of committed resources to meet CAISO's Frequency Response Obligation (FRO).
2	Secondary reserves need to be adequate.	No action required at this time.	• CAISO procures adequate secondary reserve as required by WECC and ensures the procured reserves are maintained at all times except after contingency dispatch.
3	Underfrequency load shedding actions not observed in base simulations.	See #1.	See #1.
4	Renewable penetration outside California is important since it impacts the interconnection's ability to arrest and stabilize system frequency following the loss of major generation.	Continue to monitor CAISO frequency response performance after the sudden loss of major generators in the Western Interconnection.	• Determine whether the FRO can be obtained externally or whether it should be met by resources within California. • Collaborate with other BAs and stakeholders to evaluate and potentially recommend that all renewable resources provide frequency response.
5	California's response generally meets FRO, depending on system conditions.	Continue to monitor CAISO frequency response performance following loss of large generating resources.	• Develop system capability metrics for different operating conditions and recommend changes as needed.
6	The ratio between resources providing governor response and the other conventional resources (Kt) is a good primary metric.	Begin monitoring frequency response down to the generator level.	• Investigate and verify WECC stability models and load flow models with recent frequency events. • Investigate causes and evaluate possible technical remedies for low participation in frequency control by the existing fleet.
7	Kt alone does not give all the necessary information. It also depends on the flexibility available on resources on governor control.	Begin tracking available headroom on governor responsive resource in real time.	See #1.
8	Speed of primary response or frequency response is important.	See #6.	• Work with industry to develop an appropriate metric that promotes adequate primary response.
9	Governor withdrawal can have a negative impact on frequency response.	See #6.	• Investigate causes and develop plans to mitigate governor withdrawal.
10	Impact of reduced system inertia on initial rate of change of frequency does not appear to be important.	Determine the minimum inertia required for CAISO for all hours of operation.	• Work with industry to develop an algorithm to calculate the system inertia adequacy in real time.
11	Inertial controls from wind generation helps in arresting frequency.	Survey other BAs with high renewable penetration both nationally and internationally.	• Based on best practice, consider incenting inertial response from non-synchronous generation.
12	Participation of renewables in providing frequency response is beneficial.	See #11.	• Consider expansion of grid code and interconnection requirements that ensure all generation, including VERs, are able to participate in frequency response. • Consider incenting inertial response from nonsynchronous generation.

[14] *NERC Special Reliability Assessment: Interconnection Requirements for Variable Generation* at 79–80.

13	Load control can be used to improve frequency response.	Survey other BAs using load to improve frequency response.	• Investigate market mechanisms to ensure adequate frequency response from loads.
14	Fast-acting energy storage will provide significant benefits.	Survey other BAs using energy storage to provide frequency response.	• Investigate market mechanisms to ensure adequate frequency response from energy storage.

2.5 Active Power Control

VERs connected to the transmission grid must have the ability to limit active power output. Performance characteristics of solar PV or wind resources following a disturbance must be known to system operators and planners. When the fault clears and the generation tie is placed back in service, system operators must have the ability to control the resource ramp-up to avoid an instantaneous ramp to full energy output. To maintain operating reliability, controls must be available for the VERs' ramp rate and corresponding contribution to the system during restoration. Automatic restarting—postcontingency—without control can perpetuate into further system disturbances.

Similar to conventional generation, system operators need to be able to limit power production or disconnect from the system for reliability reasons such as:

- Risk of overloads because of congestion;
- Risk of islanding;
- Risk to steady-state or dynamic network stability;
- Frequency excursions;
- Routine or forced maintenance; and
- Reconnecting to the system postcontingency.

Section 4.2 of the CAISO tariff states that a participating generator, regardless of technology, "shall comply fully and promptly with CAISO's dispatch instructions and operating orders." The only exceptions are if such compliance would impair public health or safety or is "physically impossible." Modern variable resources are physically capable of controlling output as dictated by available wind or solar radiation and the equipment rating. CAISO has generally interpreted the "physically impossible" exception to be restricted to real-time operating circumstances such as forced outages, start-up times, and, in the case of many renewable resources, lack of fuel, rather than predetermined design limitations. Thus, all generating facilities with participating generator agreements are required to operate such that CAISO can control their output under both normal and emergency conditions. The capability to limit power output from wind generation, for instance, is already incorporated into operating and market rules in NYISO[15] and AESO.[16,17]

The need for active power control capability is straightforward and promotes good utility practice and sound reliability principles. Because of contingencies, planned clearances, or unexpected generation output, situations will occur in which the system in general—or local transmission facilities in particular—will be unable to absorb all available generation. Under those circumstances, preserving system security will require reducing generation

[15] New York Independent System Operator, Inc., 127 FERC ¶ 61,130 (2009).
[16] See Section 3.1.5, Market & Operational Framework for Wind Integration in Alberta at http://www.aeso.ca/downloads/Wind_Framework_7March07_March_8.pdf
[17] AESO proposes that wind-generating facilities be adjustable from the minimum operating output to the maximum operating output at an average resolution of 1 MW.

while maintaining the resources needed for subsequent time periods or other reliability services, such as localized voltage support, frequency response, etc.

Therefore, VERs must have the ability—as is required for conventional generation—to limit the active power output in response to a dispatch instruction or operating order. This ability should apply to variable resources' full range of potential output (Pmin to Pmax) so that the variable resource reduction in output can be made in smaller increments up to a full curtailment.

Reducing the adjustable capacity increment to its smallest reasonable value allows system operators to refine their ability to address reliability concerns. System operators can maximize the output of variable resources without having to rely on less-certain solutions of complete resource curtailment. Adopting a proposal similar to that of AESO promotes the objectives of an RPS, the economics of variable resource development and, most importantly, the reliability of the grid.[18]

Like other generating facilities, VERs are expected to interface with the system operator in a similar and consistent manner. As such, VERs should be able to receive and respond to automated dispatch system instructions and any other form of communication authorized by system operators. VER response time should conform to the periods prescribed by CAISO's tariff. For CAISO, in the event that generation management is insufficient, system operators will send instructions to the participating Transmission Owners (TOs) to disconnect the variable resources. Also, if a variable resource is ordered off-line, the plant operator must not reconnect the plant to the grid without prior approval from CAISO—as applicable to other generating resources—and may be required to ramp up in a controlled manner.

CAISO anticipates using this feature as needed to address grid reliability issues and supply surplus situations, or in response to stakeholder-developed market rules. CAISO intends to initiate a stakeholder process to establish rules governing the circumstances and uses of this feature.

2.6 Reactive Power Control

Uniform requirements for asynchronous generating facilities to provide reactive support reflect the need to maintain voltage schedules with static and dynamic components within a tolerance of nominal voltage (e.g., 2 percent of nominal voltage). FERC Orders 661 and 661-A require interconnection studies to assess whether wind facilities must provide reactive support. However, this approach may not be sufficient as it cannot address all operational scenarios that may require reactive support. By design, interconnection studies are time-consuming and iterative. Applying a uniform reactive power standard to asynchronous generating facilities eliminates situations in which projects interconnecting at a later time may need to wait for additional reactive power resources to compensate for unstable voltage conditions on the grid.

A uniform requirement also enhances the reactive capabilities on the system, relative to an ad-hoc approach, based on site-specific requirements that are determined at the time of interconnection.[19] This perspective is consistent with the special reliability assessment of the NERC IVGTF,[20] which also recommends that NERC make necessary revisions to Reliability Standards that require all generators to provide reactive support and maintain

[18] NERC Special Reliability Assessment: Interconnection Requirements for Variable Generation, pg 82–83. Referenced in Appendix 1.

[19] See written statement of Jeff Billo for April 17, 2012 Federal Energy Regulatory Commission Technical Conference in Docket AD12-10 at 4–6. http://www.ferc.gov/EventCalendar/Files/20120417082804-Billo,%20ERCOT.pdf

[20] http://www.nerc.com/files/IVGTF_Report_041609.pdf

voltage schedules.[21] The IVGTF concluded that distributed generation resources that impact BPS reliability also be included.

In July 2010, CAISO filed a tariff amendment[22] to revise interconnection requirements for new asynchronous generating facilities above 20 MW seeking to interconnect to the CAISO grid. Among other requirements, the amendment proposed requiring wind and solar PV interconnection customers to provide reactive power capability and maintain voltage controls.[23] At the time, CAISO concluded that asynchronous generating facilities had the technical capability to provide reactive support through (1) generating units that comprise an asynchronous generating facility, (2) switched or variable reactive compensation devices within the facility, or (3) a hybrid of these two options. CAISO provided evidence that equipment was readily available for asynchronous generating facilities to provide reactive support through inverters or reactive devices.[24] Adopting a uniform reactive power standard will help promote renewable integration, grid reliability, and efficiency, and it will provide increased resources to effectively plan and operate the system.

2.7 CAISO Recommendations

- NERC's IVGTF recommends considering whether to require wind turbines to provide inertia response.[25] CAISO concurs with this recommendation and concludes that these resources should have the ability to automatically reduce energy output in response to high system frequency.
- Requirements for asynchronous generating facilities to provide reactive support should be considered for adoption.

[21] Draft NERC Specific Reliability Assessment: Interconnection Requirements for Variable Generation at 2–3: Referenced in Appendix 1.
[22] http://www.caiso.com/Documents/July2_2010Amendment-modifyinterconnectionreqsapplicable-largegenerators.pdf
[23] On August 31, 2010, FERC issued an order accepting in part CAISO's filing. *California Independent System Operator Corp*. 132 FERC 61,196 (August 2010).
[24] Prepared Testimony of Reigh Walling at 20–26 filed in support of CAISO July 2, 2010 transmittal letter in Commission Docket ER10-1706.
[25] NERC Special Reliability Assessment: Interconnection Requirements for Variable Generation at 83–84. Referenced in Appendix 1.

Chapter 3 – Reactive Power Control and Voltage Regulation at the Interconnection Point

3.1 Power Factor Requirements for Asynchronous Variable Energy Resources

CAISO proposes to file a tariff amendment with FERC requiring asynchronous VERs to provide reactive power output within 0.95 lag to 0.95 lead as measured at the point of interconnection. This requirement ensures that variable resources provide sufficient reactive power to maintain a specified voltage schedule in accordance with the CAISO tariff.

This 0.95 lag to 0.95 lead design recommendation is consistent with the capabilities already imposed on wind facilities under Appendix H of the Large Generator Interconnection Agreement (LGIA) pursuant to FERC Order No. 661-A. However, CAISO proposes the following key revisions related to this recommendation:

- The power factor requirements (0.95 lag to 0.95 lead) shall apply to all asynchronous resources.
- The requirement will apply without the need to perform an interconnection study.

Extending Order No. 661-A beyond wind facilities to solar PV generators or other asynchronous technologies is appropriate given the similarity in power converter systems used by such technologies. Asynchronous variable resources (e.g., wind and solar) use inverter-based technology to deliver power to the CAISO grid in a synchronous manner. Both wind and solar PV facilities consist of multiple generating units. Extending Order No. 661-A from wind to all VERs is a logical progression.

CAISO is not planning on applying this requirement to any asynchronous generating facility that has an executed LGIA or has been tendered an LGIA as of the date this proposal is approved by the CAISO Board of Governors. In addition, the requirement will not extend to any wind facility in the serial interconnection study group[26] without an LGIA or tendered LGIA, to the extent it was not required by a completed system impact study to provide 0.95 lag-and-lead power factor. Further, to the extent an asynchronous generating facility has executed an LGIA that provides for the existing lag-and-lead requirement, the interconnection customer may inform CAISO that it elects to comply with the revised requirement.

The reactive power sources needed to comply with this design requirement can be provided by the inverters associated with the asynchronous generation, switched or fixed capacitors, static devices (such as a STATCOM), or a combination of these sources.

CAISO is aware that Order No. 661-A placed the burden on the Transmission Operator to establish the need for a power factor requirement. CAISO's 2007 *Integration of Renewable Resources* study, based on transient and post-transient analyses, concluded, "[a]ll new wind generation units must have the capability to meet WECC requirements of ±0.95 power factor. This reactive capability is essential for adequate voltage control." This also supports CAISO's recommendation to make the power factor requirement mandatory.

3.2 Voltage Regulation Requirements

Article 9.6.2 of CAISO's LGIA establishes the requirement for an interconnection customer to maintain voltage schedules. This is applicable to all generators—conventional as well as VERs. To reliably operate the transmission system within an acceptable voltage range at the point of interconnection, CAISO proposes that all

[26] Serial group is referred to as "first-in, first-out" study approach.

new generators connecting to the CAISO system adhere to these requirements. The bullets below outline some specifics related to designing the voltage regulation mechanism. Variable generator resource owners or operators should:

- Install an automatic voltage control system so that the generating facility can help regulate the transmission voltage and not increase the reactive burden at the point of interconnection under both steady-state and disturbance conditions, as per the voltage schedule.
- Assure reactive power devices that are normally in service and used to vary a generating facility's reactive power output are under the control of the automatic voltage control system.
- Coordinate with the TO and CAISO for voltage schedule requirements at the point of interconnection.

The automatic voltage control system should be required to regulate the voltage at the interconnection. However, in some circumstances, it may be more efficient or necessary (as determined by CAISO in coordination with the PTO) to regulate the voltage at a point on the generator's side of the interconnection. Note: Regulating voltage to a point other than the interconnection will not change the power factor requirements (i.e., the VER is still required to have sufficient reactive capability to maintain a 0.95 lag-and-lead power factor at the interconnection).

Each generation facility should design its systems to operate in either voltage control or power factor control mode. Based on the voltage schedule or power factor set point provided, the generation facility should be able to produce and absorb voltampere (var) reactive power in such a fashion as to meet the desired voltage and power factor setting at the interconnection point. The normal operation mode for generators is automatic voltage control mode.

As shown in Figure 7, for voltages between 0.90 and 1.0 p.u., the asynchronous resource must be able to provide maximum reactive support to the system. Likewise, for voltages between 1.0 and 1.1 p.u., the asynchronous resource must be able to provide full bucking at the point of interconnection (POI).

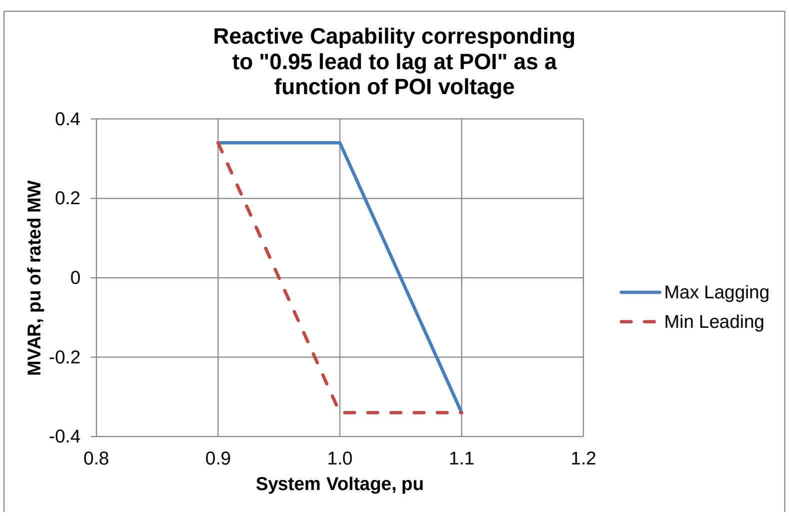


Figure 7: Reactive Capability of all Resources Including VERs

3.3 CAISO Recommendations

CAISO recommends a power factor requirement so that asynchronous VERs can provide reactive power output within 0.95 lag to 0.95 lead as measured at the point of interconnection. This requirement ensures variable resources provide sufficient reactive power to maintain a specified voltage schedule in accordance with the CAISO tariff.

Chapter 4 – Distributed Energy Resources

The amount of distributed energy resources (DERs) present on the electrical grid is forecast to grow in the next decade. The distribution system mainly delivers power from the high-voltage transmission network, and in the past, the amount of distributed generation resources connected at that level was relatively small. Therefore, its impact on BPS reliability was also relatively small. As there is a change in certain areas toward more bidirectional flow, the impact on reliability needs to be understood and managed. This section of the report addresses the impacts these resources will have and sets out mitigating strategies to ensure continued reliability in systems with large amounts of DER. This topic is also discussed in detail in NERC's IVGTF report, *Potential Reliability Impacts of Distributed Resources*.[27]

If variable energy generators are developed on a large scale at the distribution system level, then any impact of this penetration on the transmission system will need to be analyzed. A large majority of DERs are not visible to BPS operators. Many distributed resources are connected according to the IEEE 1547 standard, which can cause performance issues if fault ride-through capability is limited.

If installed in large amounts, PV inverters can also affect the frequency response and voltage profile of the system. On the other hand, resources such as controllable generation, demand response, plug-in electric vehicles (PEVs), or distributed storage could be valuable resources for reliability purposes if considered properly in planning and operating the BPS. DERs may also benefit the system by reducing peak demand and thereby eliminating or delaying the need for transmission upgrades.

According to NERC, the following factors associated with DERs are most likely to impact BPS reliability and must be considered by planners, operators, and policy makers:

- Response to faults such as low-voltage ride-through, frequency ride-through, and coordination with the IEEE 1547 interconnection standards for distributed generation.
- Non-dispatchable ramping and variability of certain DERs.
- Potential system protection considerations.
- Disconnection during underfrequency load shedding and reducing frequency further.
- Coordination of system restoration.
- Scheduling and forecasting impacts on base load and cycling generation mix.
- Impact on base load generators (e.g., increased cycling).
- Reactive power control.
- Distributed connected devices that wish to participate in ancillary service markets.
- Impacts on forecast of apparent load seen by the transmission system.

These factors will impact the BPS at different penetration levels, depending on the characteristics of the particular area they are connected to. Some factors will need to be managed by technical requirements (grid code) for the distributed resource itself, while others need the BPS operator to adapt new planning and operational methods. For example, DERs affect the power flow on the transmission and subtransmission

[27] http://www.nerc.com/files/IVGTF_TF-1-8_Reliability-Impact-Distributed-Resources_Final-Draft_2011%20%282%29.pdf

systems, which can result in thermal overloads or significant changes in profile. Also, the uncertainties associated with the variable output (DERs in aggregate) can impact forecasting and planning for demand served by transmission resources. Added complications for the system operator are introduced because of limited monitoring and control of the output from these DER resources. Also, high DER penetration has been shown to affect the transient and small signal stability, which can be positive or negative depending on the DER type (e.g., inverter-connected DERs can affect stability, depending on control schemes employed).

Voltage is often degraded from the lack of voltage control of many DER technologies. Improving visibility for distributed energy resources and establishing a requirement to regulate the aggregated voltage of an interconnection transmission point may be a solution.

The interconnection requirements for new generators connecting to the distribution system are different and in some cases conflict with interconnection requirements for the transmission system. One such conflict exists between IEEE 1547 and UL 1741 standards that require inverter-based generation to trip offline for faults near a generator because of low voltages at the inverter terminals. If a significant amount of generation on the distribution system starts tripping for faults, this may pose an added and cascading burden on the transmission system. The NERC IVGTF for Task 1.7 is addressing this issue.

The potential impacts of DER can be mitigated. Greater visibility and control through smart grid technologies will increase communication and visibility to the system operator; this will then have the impact of aggregating forecast variability so BAs can manage this in much the same way that they will deal with transmission-connected wind; i.e., by using flexibility in their generation mix to accommodate ramping. Guidelines, procedures, and requirements will need to be developed, however, to ensure that interconnection of DER does not significantly affect BPS reliability. These programs and standards may take the form of a grid code similar to that established in Germany for medium-voltage generation interconnection. The potentially competing interests of distribution system and BPS needs as evidenced between these types of standards and IEEE 1547 will have to be reconciled.

Chapter 5 – Steady-State, Short-Circuit, and Dynamic Generic Model Development of Variable Resources

Publicly available standard models that are able to reasonably represent key performance relevant to BPS studies are needed to better understand the operating performance of VERs in relation to the performance of the electric grid. The process and need for model validation applies to any and all levels of modeling. Models are required to perform power-flow, short-circuit, and stability studies necessary to ensure BPS reliability.

System models are required for generation equipment at three levels:

- Models for assessing the steady-state behavior of the units and their fault current contributions for protection system analysis;
- Models for emulating the dynamic behavior of the units for BPS time-domain stability analysis; and
- Detailed, equipment-specific (three-phase) models for specialized studies.

Within the CAISO system, specific issues include the:

- Inability to study all operational scenarios with the different variability and unlimited grid configurations in real time;
- Difficulty in obtaining accurate dynamic models or design parameters for wind and solar plants at time of application;
- Need for standardized generic models to conduct reliability studies; and
- Limited ability to update nomograms based on real-time on-line and look-ahead voltage and dynamic stability analysis, including the impact of VERs.

NERC's Modeling, Data, and Analysis (MOD) Reliability Standards require registered entities to create procedures needed to develop, maintain, and report on models to analyze the power system steady-state and dynamic performance (MOD-011 and MOD-013). Equipment owners are required to provide steady-state and dynamic models (MOD-012) to the Regional Entities. This information is required to build a reasonable representation of the interconnected system for planning purposes, as stated in MOD-014 and MOD-015.[28]

However, the NERC IVGTF[29] identified enhancements to NERC Reliability Standards. The IVGTF concluded that nonproprietary and publicly available models for the simulation of steady-state (power flow), short-circuit (fault calculations), and dynamic (time-domain simulations) behaviors of generation resources must be made readily available for use by power system planners. Furthermore, these models should be routinely validated to ensure they properly represent VER power plants in BPS studies. A model is valid if its dynamic behavior is close enough to reality that its influence on the network of interest (i.e., used for power system studies) is consistent with the fidelity of model structures and available data for the power system and other generation, as it pertains to the phenomena of interest (i.e., in stability studies). That is, perfect-curve fitting is not necessary but, to the extent possible, erroneous model dynamics must not result in a notable overdesign or underdesign of the network.

[28] http://www.nerc.com/page.php?cid=2|20
[29] http://www.nerc.com/files/Standards%20Models%20for%20Variable%20Generation.pdf

Many wind and PV facilities consist of large numbers of generators connected to collector circuits that are linked to a substation. As such, the dynamic behavior of inverter-based systems during fault conditions must be verified to ensure accurate simulation during system fault conditions. Most inverter-based asynchronous generators use inverters that limit and sometimes eliminate current during system fault conditions. In these cases, accurate modeling is critical, because as the penetration level of these generation systems increases and the level of conventional synchronous generation decreases, available system fault current also decreases. This may have an impact on protective relaying clearing time, which in turn may require lowering system operating limits.

The IVGTF concluded that modifications to NERC Reliability Standards may be needed to enhance: (1) the technical requirements (i.e., the need to define, measure, and validate a model and its parameters), and (2) the procedural requirements (i.e., the functional model of how this technical requirement should be met, reported, and monitored) that are needed to ensure models are validated sufficiently and provide clarity around the modeling of VERs. The IVGTF highlighted several enhancements to NERC Reliability Standards FAC-001, MOD-11 through MOD-13, and MOD-24 through MOD-26. These recommendations are detailed in NERC's *Standard Models for Variable Generation* NERC report.[30]

[30] ibid

Chapter 6 – Current Forecasting Ability and Future Needs

System operators must accurately forecast load as well as detect and anticipate changes in variable resource generation on a day-ahead, hour-by-hour, and real-time basis to maintain grid reliability and reduce systems' operational costs. Improvements in forecasting are especially important for three reasons:

1. Improving renewable resource forecasting will allow system operators to more accurately procure the proper flexibility and reserve generation required to maintain grid reliability;
2. Procuring energy and ancillary services in the day-ahead time or any time before real time minimizes energy procurement costs; and
3. Minimizing forecast errors would ensure the necessary ramping and ancillary services are committed to handle fluctuation and eliminate ramping infeasibility.

To improve load-forecasting abilities, CAISO installed a new fifth-generation load-forecasting tool that will be able to handle multiple sources of input, including multiple weather services that provide forecast data for meteorological conditions such as wind speed, temperature, barometric pressure, and solar irradiance.

This tool provides an ensemble of load, wind, and solar energy forecasts that feed into CAISO internal algorithms to determine a confidence band around the forecasts. This probabilistic forecast approach provides a larger suite of tools for grid operators to use for improving their forecasting accuracy.

To enhance its ability to forecast loads, CAISO is also incorporating renewable forecasts into grid operational systems that include behind-the-meter influences of distributed energy resources, which allows CAISO to better forecast the true conforming load (net load).

6.1 Forecasting Needs

Weather conditions in California have helped define the load zones. In any given hour, energy requirements in the San Francisco Bay Area can vary drastically from the non-Bay Area because of overcast conditions caused by proximity to the coast. For example, on June 1, 2012, the temperature in Sacramento at 11:00 a.m. Pacific was 90^{o} F with cloud coverage at 0 percent. At the same time, about 100 miles away in San Francisco, the temperature was 62^{o} F with 86 percent cloud coverage.[31] A similar situation exists in southern California, where the area is divided into coastal and inland areas.

In the past, the load by area was determined by using a similar meteorological and load consumption day. The forecast needs were limited to either day-ahead (midnight to midnight) or hour-ahead (two hours and 15 minutes before the operating hour) forecasts. There was also a limited need to produce a separate forecast for renewables (wind and solar). In 2004, wind production forecast was developed for the first entrants of PIRP. Using the automated load forecasting system (ALFS) neural network forecast engine, CAISO is able to define forecasting algorithms along with meteorological data.

The CAISO market redesign, which was implemented in 2009, defines the frequency of forecasts and their timelines. The day-ahead forecast is still midnight to midnight before the market closes at 10:00 a.m.; however, the hour-ahead forecast for load has decreased from two hours to one hour and 15 minutes before the operating hour. The forecasts for variable resources are provided one hour and 45 minutes before the operating hour.

[31] http://www.worldweatheronline.com

6.1.1 Load Forecast Horizons

- **Day-Ahead:** (Midnight to midnight the next day) broadcast time at 10:00 a.m. the day before the trading day for all 24 hours.
- **Hour-Ahead Scheduling Process:** Forecasts for the four 15-minute intervals starting 75 minutes before the operating hour.
- **Real-Time Pre-Dispatch:** The binding 15-minute interval 30–45 minutes before the interval.
- **Real-Time Dispatch:** The binding 5-minute interval 10–15 minutes before the interval.

6.1.2 Wind and Solar Forecast Horizons

- **Day-Ahead:** The full day midnight to midnight before the day-ahead market closes at 10:00 a.m. the day before the trading day.
- **Hour-Ahead Scheduling Process:** Forecasts for the four 15-minute intervals starting 105 minutes before the operating hour.
- **Real-Time Pre-Dispatch:** The binding 15-minute interval 30–45 minutes before the interval.
- **Real-Time Dispatch:** The binding 5-minute interval 10–15 minutes before the interval.

Eligible intermittent resources (EIRs) and PIRP resources receive their forecasts directly from CAISO via a forecast service provider 105 minutes before the operating hour. The Scheduling Coordinators (SCs) in turn may or may not offer these forecasts as self-schedules.

6.2 Forecasting Definition, Accuracy, and Matrices

The crucial difference between the variability of renewable generation and demand is predictability. Demand can be anticipated to within a few percent points based on history, weather forecasts, and timing of major events such as television programs. Renewable generation depends primarily on weather, which does not occur in regular patterns and is not correlated to diurnal patterns of demand. Ramping up or down dispatchable power sources (such as natural gas turbines or hydroelectric power) to follow variable generation is a fundamental reliability challenge.[32]

Forecasts must improve to accommodate the two high-priority challenges in generation variability: up-ramps at times of low demand and down-ramps at times of high demand. In the former case, conventional reserves may already be turned off so that accommodating the up-ramp may require turning down base-load conventional generation or curtailing renewable generation. Both options can be inefficient and expensive. In the latter case, most conventional reserves may already be turned on, leaving few options for compensating the power lost in the renewable down-ramp. In the February 26, 2008 ERCOT event, service to certain customers had to be curtailed because of an earlier-than-expected wind down-ramp.[33]

There are numerous ways to express the forecast accuracy. The issue with stating accuracy is the interpretation of the data. Different forecast time periods or other assumptions can give vastly different answers to the forecast accuracy.

[32] K. Porter and J. Rogers, Central Wind Power Forecasting Programs in North America by Regional Transmission Organizations and Electric Utilities, NREL/SR-550-46763, December 2009.
[33] E. Ela and B. Kirby, *ERCOT Event on February 26, 2008: Lessons Learned*, NREL Technical Report NREL/YP-500-43373 (2008), www.nrel.gov/docs/fy08osti/43373.pdf, accessed May 15, 2010.

6.2.1 Definitions of Accuracies MAPE and MAE

Mean absolute percentage error (MAPE) takes the difference between forecast and actual production and divides it by the actual production for each interval to produce the percentage error. Periods longer than the intervals are the average of percentage errors of those intervals in that period.

$$MAPE = \frac{1}{n}\sum_{t=1}^{n} \left| \frac{A(t) - F(t)}{A(t)} \right| \tag{1}$$

Where A(t)[34] *is the actual production and F(t) is the forecast production.*

Mean absolute error (MAE) takes the difference between forecast and actual production and produces the average for all intervals. The average for an interval is divided by the actual or the capacity to produce a percent error for that period. The common industry practice is to use the capacity when measuring wind and solar forecast errors.

$$MAE = \frac{1}{n}\sum_{t=1}^{n} \left| \frac{A(t) - F(t)}{C} \right| \tag{2}$$

Where A(t) is the actual production, F(t) is the forecasted value and C is capacity.

6.3 Separate Distributed Generation Forecast from Behind-the-Meter Load and Generation

As distributed and behind-the-meter generation continues to grow, particularly in California, isolating each of these elements will help operators better understand generation performance and profiles. CAISO is building a model to forecast the deviations caused by behind-the-meter influences. For example, rooftop PV panels cause deviations of more than 500 MW[35] during rainy and cloudy days. This effort will forecast the profile of influences and drivers to better determine accuracy impacts.

6.4 Weather Forecast Improvement

The confidence level of forecasts is as important as accuracy. Low confidence levels require operators to maintain high levels of reserves even if the forecast itself calls for steady output. Estimating the confidence level of forecasts is becoming more common, but the techniques must be refined.

Wind and solar energy production is dependent on localized weather information. The electrical grid has evolved to the point at which operators need to know what the weather will be within a one-square-mile area in the next two hours or less.

Since 2004, CAISO has received hourly energy forecasts for wind farms participating in its market from an external forecast service provider. However, two-hour-old forecasts are highly weighted on the current weather condition. Because of the lack of upstream, or ahead-of-the-air-mass observation points, the forecasts tend to be accurate but too late (as shown in Figure 8) to predict the actual wind farm production. This is referred to as the forecast being “out of phase.”

[34] MAPE works well as long as the actual production is not zero or close to zero.
[35] Based on 1300 MW of installed rooftop solar capacity

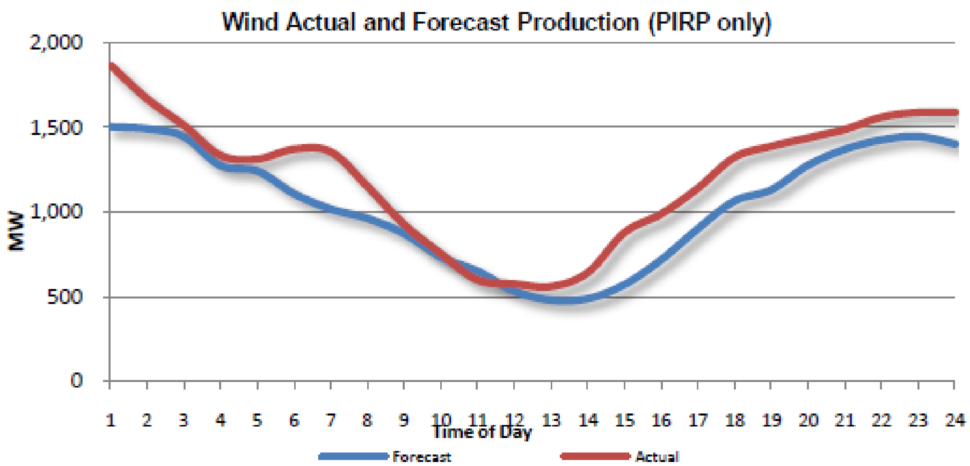


Figure 8: Forecast and Actual Production – Out of Phase

Forecast service providers can increase the accuracy of forecasts through three enhancements. The first is the high-quality data. Studies have shown that data from wind farms are of varying quality.[36] These same studies have shown that the forecast improves with high-quality meteorological data. CAISO plans to improve its data monitoring to ensure high-quality data is being sent to system applications and forecast service providers.

The second enhancement that forecast service providers feel is important is more meteorological observation points situated in correct locations. For wind, the observations must be at hub height. Simply taking an observation at a single point upstream from the wind farm is insufficient to predict wind farm production. Forecast service providers believe that observing the atmosphere in a three-dimensional view over a given time period will yield the highest accuracy. There are also forecast service providers who think the added observations will add little value to the forecast accuracies. CAISO will be working with a forecast service provider to substantiate or disprove this hypothesis.

Solar power forecasting is a nascent industry. The issues for solar forecasting are similar to wind forecasting with a major addition: identifying, tracking, and predicting where cloud cover will move and how it will affect solar PV or concentrated solar plant (CSP) output. Siting the right equipment at a solar plant or upstream of the site is an issue CAISO and various forecast service providers are evaluating. CAISO is also working with the University of California, San Diego to improve the intrahour forecast.

6.4.1 Weather Telemetry Requirements

CAISO developed its PIRP in 2002 when there were few wind energy farms in the United States participating in any energy market. Little was known about the telemetry requirements needed to predict energy production at a single wind park of less than 10 square miles. At the time, CAISO thought the actual wind speed at a single average hub height point source was sufficient to help predict the wind.

However, not all wind generation sites are built on level land at sea level. Therefore, it has become increasingly important to take wind readings from numerous wind park locations, including on top of the turbine nacelles. CAISO requires wind sites to provide wind speed and direction from a meteorological tower at the average

[36] http://www.caiso.com/Documents/Paper-ImprovingForecastingThroughAccurateData.pdf

turbine hub height along with the nacelle anemometer wind speed and direction. CAISO also collects basic site meteorological information such as barometric pressure, ambient temperature, and real-time production.

Unlike wind production, solar production is based on the irradiance (i.e., sun energy) that hits the earth. This is measured in watts per meter squared (watts/m^2). CAISO acquires the same basic meteorological data as wind sites plus irradiance data along with the solar PV panels' back plane temperature, which helps calculate the heat losses.

By knowing the meteorological conditions,[37] including the irradiance value at solar plants, forecasters can better predict production of VERs. It is critical for load and production forecasts to collect real-time meteorological and production data from generators. In CAISO, data are collected from the sites through a remote internet gateway and then transferred via a secure virtual private network connection back to CAISO. This data then passes through the energy management system (EMS), then to the plant information (PI) system, where it can be accessed by applications such as PIRP and ALFS.

6.5 Wind Short-Term Event Predictor

Operator experience and confidence are critical to the success of forecasting. Just as airline pilots come to know that weather and turbulence forecasts need not be perfect to be useful, with experience system operators will improve their ability to use forecasts to their advantage. It may be more useful to view forecasting in terms of identifying periods of operational risk or uncertainty, so that operators can take mitigating action under those conditions instead of focusing exclusively on the accuracy of forecasting. In addition, more integration of forecasts and forecast uncertainty with power system risk analysis tools is increasingly necessary to operators to receive warnings of risk to their power systems in a more holistic way.

An example of CAISO's efforts to integrate forecasting is the wind forecast situational awareness tool that provides grid operators with advance warning of situations in which there is a high probability of a large change in wind power production over a relatively short time period. This type of event is commonly called a "wind ramp." This information is needed on multiple look-ahead time scales, especially within a six-hour horizon. This will become a more urgent need within two to three years as wind plant installations increase over the next three to five years.

Intrahour wind-ramp forecasting by its nature is more challenging than hourly or daily average wind-power forecasting. Conventional generation power production is relatively predictable and stable—online generators generally operate at minimal or near full production. Wind-ramp forecasting skills are dependent on accurate prediction of the occurrence, timing, and amplitude of relatively infrequent events that are typically driven by the most complex and uncertain weather situations. Forecast wind-ramp events are subject to errors in timing, amplitude, and duration, partly because forecast skills in this relatively new area are just now developing.

ERCOT uses a wind-ramp tool developed by AWS Truewind, LLC in collaboration with ERCOT system engineers to help plan for wind ramps. Ramps can be caused by air mass changes, thunderstorms, cold fronts, nocturnal stabilization, pressure changes, and other transient atmospheric events. The large-ramp alert tool makes calculations six hours ahead to warn system operators of the risk of large and rapid increases or decreases in wind output. The ramp forecast calculates the values of magnitude and duration and estimates the probability of a large ramp event beginning in a particular interval. Information regarding the weather event that is most

[37] CAISO collects production data from all generation sites 10 MW and above, but collects meteorological and production data from wind and solar sites at or above one MW every four seconds.

likely to cause the ramping event is also included, as well as additional characteristics for each predicted ramp event, such as start time, duration, and maximum ramp rate.

6.5.1 Goals

The goal is to provide operators with advance notice of an impending ramp with some level of confidence of the event location and time. For example, the tool could predict an 80 percent chance that a front with winds gusting to 50 mph will pass through the Solano area within 45 minutes, which indicates a ramping event. This tool will enhance operators' decision-making processes for procuring energy, ancillary services, unit commitment, and dispatch.

6.5.2 Objectives

The study will answer the following questions, among others:

- What defines a wind-ramp event?
- What atmospheric conditions will most likely cause a ramp event?
- When will ramp events most likely affect the grid?
- What is the best way to measure ramp forecast accuracy?
- What situational displays are best to present upcoming ramp events?
- How far in the future can a ramp event be predicted?

6.6 Short-Term Solar Forecasting

Solar energy production adds a new dimension of variability and an element of uncertainty to how grid operators manage the system. Although improving irradiance forecasting has been an ongoing effort for the scientific community, accurate forecasts are now needed to reliably predict power production for solar PV and concentrated solar thermal parks.

Post-processing techniques are methods used to obtain a probabilistic point of view of the accuracy of the output once the model's output is obtained. This is usually done with techniques that mix different outputs of different models convoluted into strategic meteorological values to provide a better estimate of those variables and a degree of uncertainty.[38]

System operators generally need energy forecasts from individual solar farms in three specific time periods:

- **Day-ahead:** 18–42 hours before the operating hour (for CAISO);
- **Hourly:** 105 minutes before the operating hour (for CAISO); and
- **Intrahour:** every 15 minutes for the next two hours (for CAISO).

These forecasts look at the average forecast for the periods. In the case of real time, the forecasts are based on a persistence forecast. The day-ahead period is based on climatologic forecasts.

Using an average deterministic forecast, the variations in real-time solar production (because of deviations from cloud formations) tend to be smooth, which minimizes errors and leaves grid operators blind to intrahour deviations. These uncertainties can have a profound effect not only on energy replacements costs, but also on system reliability.

[38] Bacher, P., Madsen, H., Nielsen H.A. Online short-term solar power forecasting. Solar Energy. Vol 83, Iss. 10, October 2009: 1772–1783

Chapter 7 – Operating Tools

Load-following (flexible needs) and regulation requirements can be met by committing additional capacity in the day-ahead time frame. However, taking such an approach would be economically and perhaps environmentally inefficient. Tools must be developed that dynamically correlate system conditions and the additional ramping and regulation needs triggered by the deviation between forecast versus actual load and variable resources output. The current forecasting capabilities (for VER as well as for load served by DER) are inadequate to allow wholesale market mechanisms to efficiently address flexibility needs throughout the operating day.

To assist operators in making informed decisions to minimize potential reliability concerns that arise from the lack of renewable resources, CAISO, in conjunction with the Pacific Northwest National Laboratory, developed a ramping tool.[39] This ramping tool uses the most up-to-date load forecast, wind forecast, resources committed through the various market runs, generator-forced outage information, and related stochastic relationships between the input datasets. The ramping tool visually displays the ability of committed dispatchable resources to meet expected load and variable ramp requirements within a user-specified confidence band.

Primary objectives of the ramping tool are to:

- Provide system operators with visual displays to keep them aware of current ramping requirements so proactive measures can be taken to minimize impacts of renewable resources on operational performance;
- Pave the way for a wider penetration of renewables into CAISO's resource mix without compromising reliability of the power supply; and
- Support the state's renewable resources integration efforts.

The ramping tool is comprised of two different applications that share the following common input dataset:

- **Load-Following Requirement Tool (24-hour look-ahead):** This tool predicts and displays in real time the load-following capacity and ramping requirements that result from uncertainties in load and renewable generation forecasts.
- **Regulation Prediction Tool:[40]** This tool estimates the upward and downward regulation requirements in terms of capacity, ramp rate, and ramp duration for each operating hour for the next operating day.

7.1 Meeting Load-Following Requirements in CAISO

System operators have the option to view load-following capacity requirements (or generation requirements forecast)[41] and the availability of various time frames in the future.

7.1.1 Generation Requirement Forecast

The screen shown in Figure 9 refreshes every minute. System operators can define a confidence range around the generation requirements forecast curve by activating the confidence ranges in a percent at the bottom left of the screen.

[39] This tool was installed at CAISO on May 4, 2011, and real-time data was fed into the database for the first time. Because the algorithm relies on statistical characteristics of various input data streams, CAISO needs to allow at least 30 days of historical real-time data to see how well the tool works.

[40] A final report of the Regulation Prediction tool is located at: http://uc-ciee.org/downloads/Day-ahead_Regulation_Final_Report.pdf

[41] Generation Requirements Forecast = Load Forecast – Wind Forecast – Solar Forecast – Interchange Schedule

A 90-percent confidence band means that there is a 90-percent confidence level that the generation requirements forecast curve can meet the uncertainty and variability associated with load, wind, and solar for any particular hour. The orange area in Figure 9 shows the required generation capability with a 90-percent confidence band, and the darker orange area shows the required capability with a 95-percent confidence band.

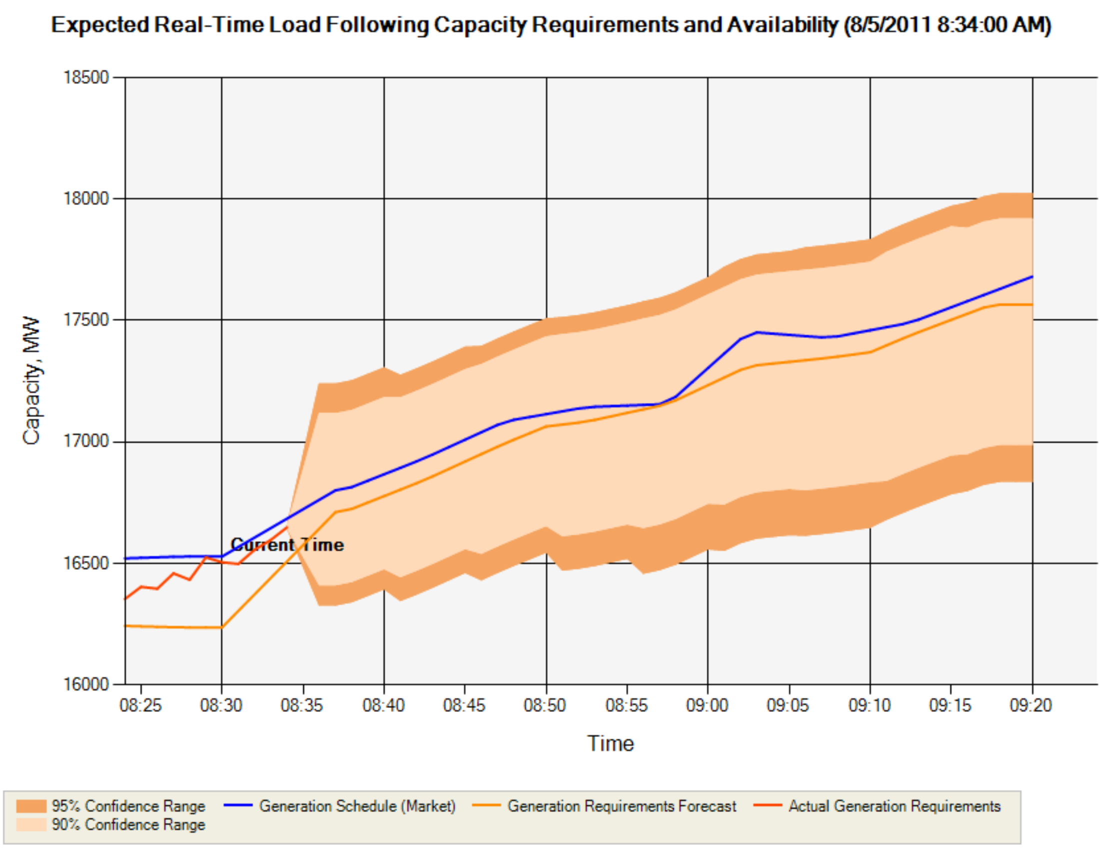


Figure 9: Real-Time Load-Following Capacity Requirement

7.1.2 Capacity Availability

The grey shaded area in Figure 10 shows the committed conventional resources available capacity, which is based on a five-minute ramp rate and is calculated each real-time dispatch run. The look-ahead horizon is the real-time dispatch five-minute interval for the next 13 five-minute advisory intervals. The available capacity is typically cone-shaped, because the available ramping capacity is calculated from the current time. For example, the capacity availability shown 20 minutes away from the current time is the actual upward and downward ramping capability over a 20-minute period of the committed conventional resources.

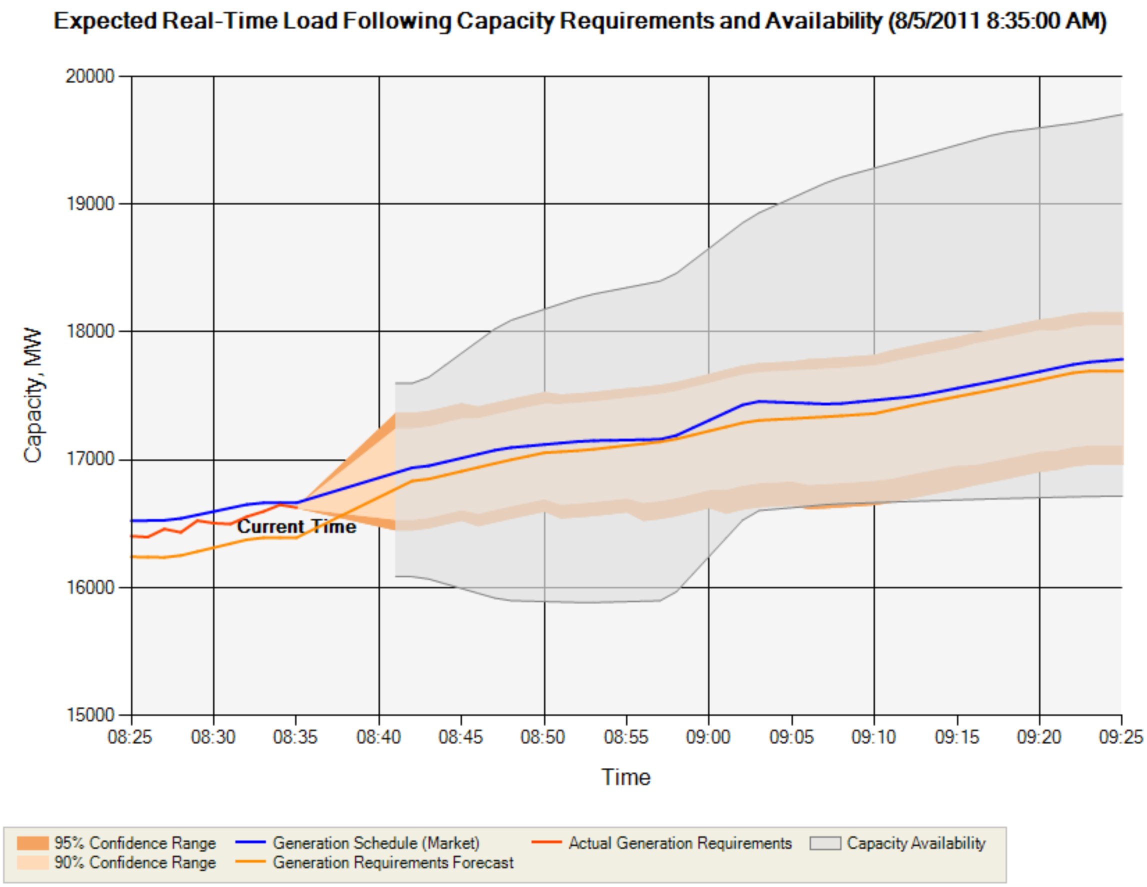


Figure 10: Capacity Availability as Determined by RTD for the Next 13 Five-Minute Intervals

When any portion of the shaded area falls within the generator requirements forecast confidence bands, the conventional resources cannot meet the capacity or ramping capability to meet the expected wind and solar uncertainty and variability for the horizon displayed.

When the "Advisory" function is activated, system operators are able to view any potential capacity shortfalls for the look-ahead horizon as shown in Figures 11 and 12.

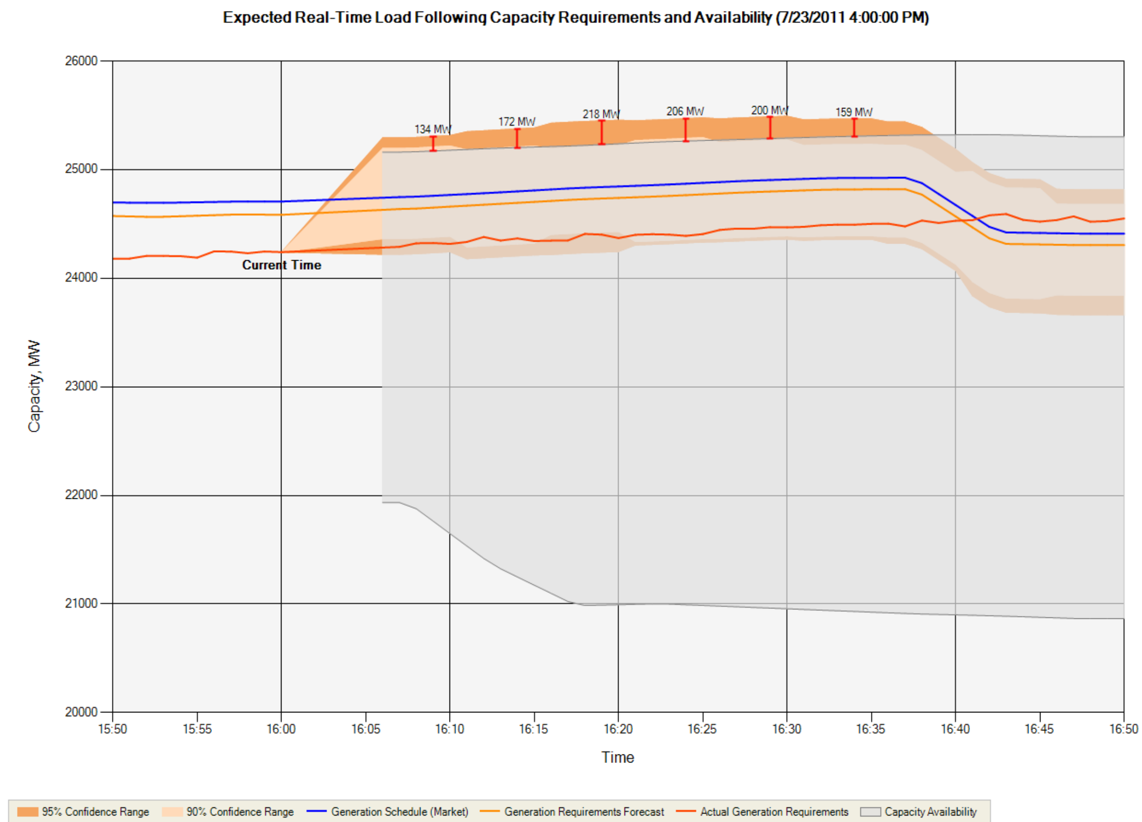


Figure 11: Potential Ramp-Up Capacity Shortfall for the Look-Ahead Horizon

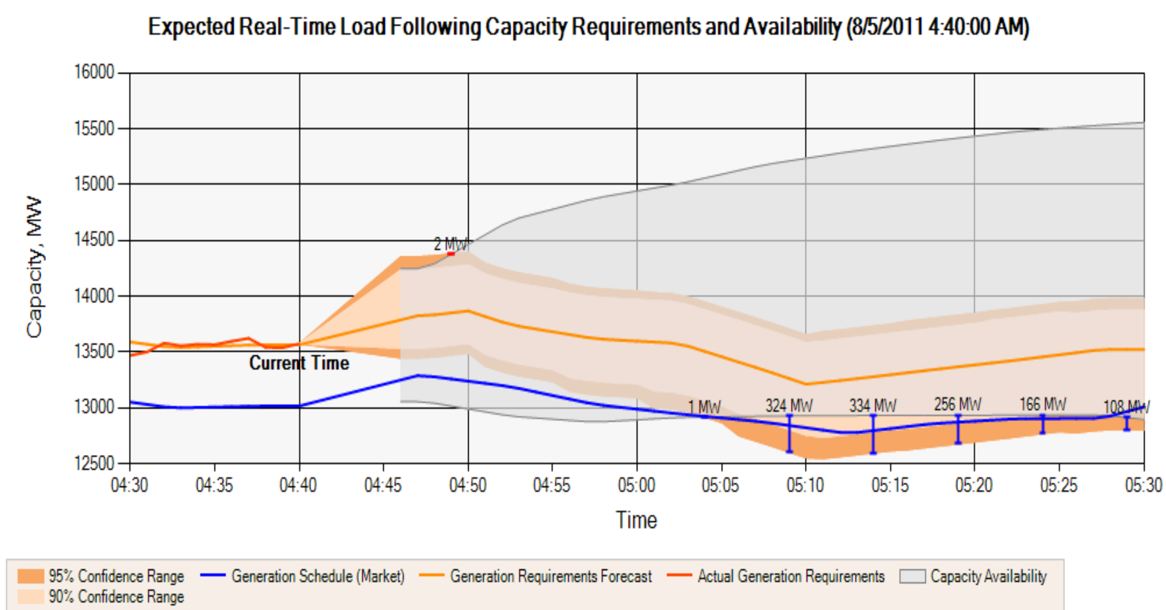


Figure 12: Potential Ramp-Down Capacity Shortfall for the Look-Ahead Horizon

7.2.3 Regulation Requirements

The regulation prediction function is designed to predict in the day-ahead time frame the hourly regulation procurement needs in terms of capacity, ramp rate, and ramp duration for the next operating day. There are three different methods for calculating the regulation capacity requirements in the day-ahead time frame. CAISO is evaluating all three methodologies described below.

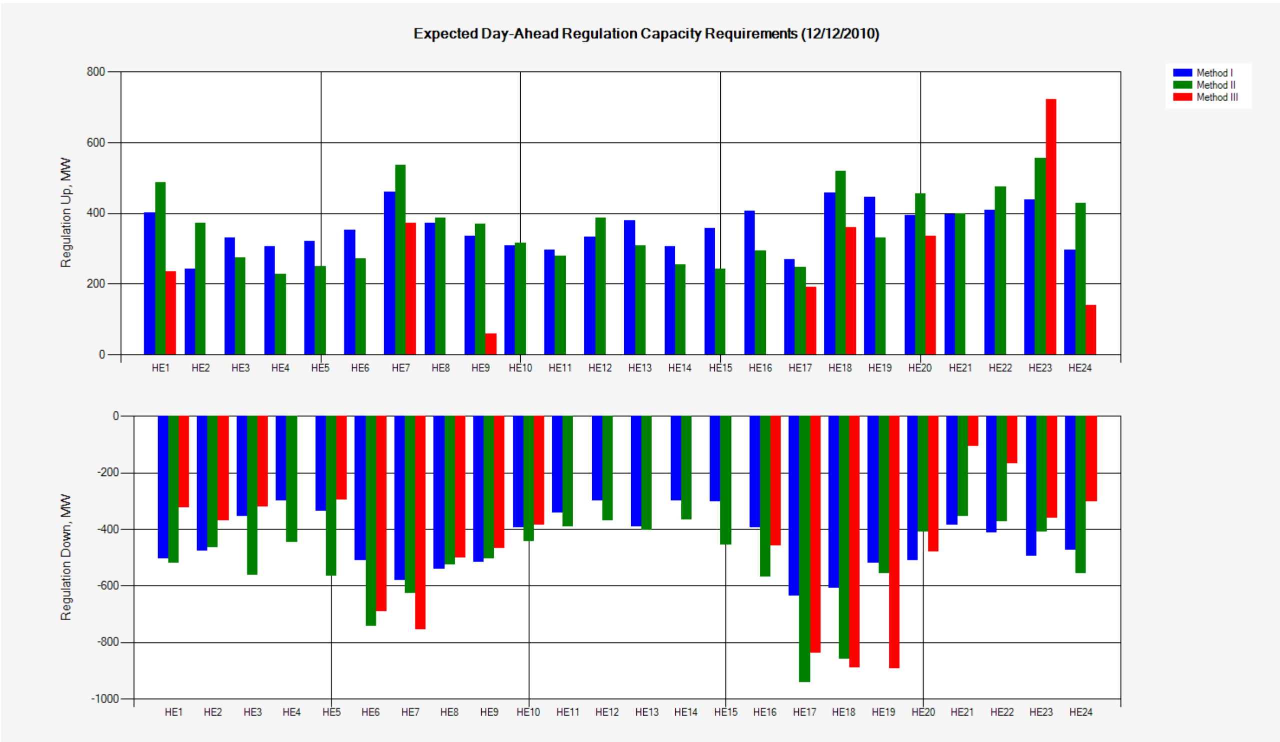


Figure 13: Hourly Regulation Needs for the Next Operating Day

Method I

Method I is based on statistical analysis of the different sources of uncertainty, such as real-time load, wind, and solar forecast errors, frequency deviations, time–error correction, and uninstructed deviations of conventional resources, that can affect regulation requirements.

The algorithm uses historical real-time load forecast errors (i.e., real-time one-minute average actual load minus the five-minute load forecast). Thus, 60 error values are calculated for each hour, or 1,800 error values in 30 days. Errors are calculated on an hourly basis (Hour 1, Hour 2, etc.). A persistence model for the wind and solar production levels is assumed to be constant for a given five-minute dispatch interval. This method also takes into account frequency deviation and uninstructed deviations on all units. Automatic time–error correction (ATEC)[42] is also factored into the calculation.

A confidence factor of 100 percent implies a zero ACE, and a confidence level less than 100 percent implies that ACE would be zero for the specified confidence level. In other words, a confidence level of 90 percent means

[42] A frequency control automatic action that a BA uses to offset its frequency contribution to support the interconnection's scheduled frequency.

that the calculated hourly regulation capacity requirements would result in zero ACE approximately 90 percent of the time. Equation (1) shows the ACE calculated formula.

$$\text{ACE*} = \Delta L - \Delta W - \Delta S - \Delta G - 10\beta\Delta f - ATEC \qquad (1)$$

Where: ΔL = real-time load forecast error
ΔW = real-time wind forecast error
ΔS = real-time solar forecast error
ΔG = uninstructed deviation on conventional resources
$10\beta\Delta f$ = frequency component of ACE (MW)
$ATEC$ = automatic time–error correction component

Method II

Method II estimates the hourly regulation requirements by performing a statistical analysis of the actual ACE signal and actual regulation on a minute-by-minute basis for each hour. For each hour there are 60 values, or 1,800 values for a 30-day moving window. This methodology mimics the old CPS2 mode in which ACE is maintained within predefined operating limits (referred to as $\pm L_{10}$). There is an option where the user can change the L_{10} values. For time *t*, the ideal regulation ramp up and down requirements are defined as:

$$R^{+}_{ideal} = R^{+} - ACE^{-} \qquad (2)$$

$$R^{-}_{ideal} = R^{-} - ACE^{+} \qquad (3)$$

R^{+} refers to regulation up values, and ACE^{-} refers to negative ACE values. Similarly, R^{-} refers to regulation down values, and ACE^{+} refers to positive ACE values. The ideal regulation up-and-down requirement assumes zero ACE and is calculated on a minute-by-minute basis for the 30-day moving window.

Method III (BAAL-ACE)

Method III takes into consideration the new control performance standard Balancing Authority ACE Limit (BAAL)[43] in its calculations. CAISO monitors its own performance against its BAAL target and takes corrective actions before one of its BAAL limits is exceeded. BAAL limit is calculated on a minute-by-minute basis based on the actual historical frequency for the past 30 days.

The BAAL limits depend on current frequency f and can be calculated using the following equation:

$$\text{BAAL (f)} = -10\beta \frac{(f_{low} - 60)^2}{(f - 60)} \qquad (4)$$

Where β is the BA's frequency bias (MW/0.1 Hz). f_{low} is the low frequency trigger limit (Hz). For WECC f_{low} is calculated as $f_{low} = 60 - 3\varepsilon_1 = 59.932$. In order to meet the BAAL standard requirement, the BA's ACE should satisfy the following constraint:

$$BAAL_{\min t} \prec ACE^{*}_{t} \prec BAAL_{\max t} \qquad (5)$$

Where:

$$ACE^{*}_{t} = ACE_{t} - REG_{t} \qquad (6)$$

And *BAAL*max*t* and *BAAL*min*t* are limits at time *t*.

[43] BAAL is designed to replace the CPS2 standard. Unlike the CPS2 standard formulated for 10-minute averages of ACE, the BAAL standard is formulated for instantaneous ACE and frequency values.

Chapter 8 – CAISO Market Enhancements

CAISO has developed a Renewables Integration Market Vision and Roadmap that takes a holistic view of the CAISO market. It identifies incremental enhancements that leverage the existing market and infrastructure to address and facilitate the transformative changes that result from the state's energy and environmental policies and emerging new technologies. This must be done in a manner that maintains reliable and efficient grid operations and spot market stability. CAISO's goal is to evolve the existing market structure to enable the following:

- Efficient and reliable operation of the grid with a more diverse and variable supply portfolio;
- Flexible accommodation of future energy policy with minimal changes; and
- Innovative use of new resource types to address future energy policy and operational needs.

California currently has a 33 percent RPS and the California Global Warming Solutions Act (see AB 32), which calls for reductions in greenhouse gas emissions. These two policy initiatives may seemingly be at odds with: 1) the increased variability resulting from a large portion of the renewables portfolio, which indicates the need for additional flexible resources (expected to be predominantly provided in the near term from conventional generation); and 2) the requirements for reduction of greenhouse gasses. CAISO is relying on stakeholders' help to determine the most effective way to evolve the market to meet these objectives. Market enhancements are intended to provide an orderly transition that offers an opportunity for a variety of solutions, including demand-side resources, storage, regional coordination, VER control, and flexible conventional generation to develop and be considered to meet the operational needs.

A significant operational challenge for CAISO is to reliably maintain continuous system balance given the variability of the energy output of VERs, which is caused by the variable nature of their fuel source (e.g., solar irradiance and wind speed). Increased variability in the output of the supply portfolio will result in less predictability and, therefore, greater operational uncertainty. CAISO must anticipate and manage this variability to balance supply and demand as well as to meet reliability criteria. Greater uncertainty indicates the need for additional resources to provide dependability at an appropriate level of confidence (i.e., to provide adequate certainty).

CAISO is actively pursuing several market enhancements to integrate renewable resources. Examples include:

- Active flexible capacity procurement;
- Dynamic transfers;
- Lower bid floor;
- Pay-for-performance regulation;
- FERC 764, intrahour scheduling;
- Proposed enhancements to the California Public Utilities Commission's (CPUC) resource adequacy program; and
- Energy Imbalance Market.

8.1 Active Flexible Capacity Procurement

Each BA will have specific needs depending on the renewable generation levels in its resource mix and the generating fleet make-up. To reliably integrate renewable resources into its generation mix, CAISO is proposing or has implemented the market enhancements outlined below.

8.1.1 Regulation Energy Management

The regulation energy management[44] functionality allows nongenerator resources such as energy storage devices and demand response resources to bid their capacity more effectively into the CAISO regulation market. This product adds depth to the regulation market by enabling nontraditional resources to provide more and potentially faster regulating resources.

8.1.2 Flexible Ramping Product

The flexible ramp product[45] will complement the existing flexible ramp constraint[46] to create an actual product that ensures sufficient upward and downward ramping capability is available in real time and that resources are appropriately compensated for providing the service. The flexi-ramp constraint—enforced since December 2011—only addresses the upward ramping capacity. Yet, with large amounts of self-scheduling renewable generation coming on-line, studies indicate that overgeneration is likely to occur. Addressing this operational concern will require downward ramping capability. Further, the short-term flexible ramping constraint does not contemplate day-ahead procurement of flexible capacity or offer any opportunity for resources to indicate their desires and costs for providing this service. The flexi-ramp product is more robust and will address these issues.

By introducing a downward flexibility product, CAISO also proposes to incentivize VERs that are capable of adjusting their output to provide downward flexibility services. In order to be eligible to participate, a resource must offer an economic bid to reduce its output and be responsive to dispatch instructions.

When designing its flexible ramp product, CAISO will address cost allocation issues by considering the causation and incentive principles. In applying these principles, both demand and supply may be allocated through the cost of flexible ramp products, based on the respective variability.

8.2 Dynamic Transfer

Most imported energy into CAISO is provided by fixed hourly schedules on the transmission interties between neighboring BAs. However, there are limited cases in which certain intertie schedules are allowed to vary within the hour—a practice referred to as “dynamic transfers.” To meet California’s RPS, CAISO is in the process of making tariff clarifications and modifications that will extend dynamic transfers to renewable energy resources.[47]

Some of the key modifications include the following:

- Hourly transmission reservation,

[44] http://www.caiso.com/informed/Pages/StakeholderProcesses/RenewableIntegrationMarketProductReviewPhase1.aspx
[45] http://www.caiso.com/informed/Pages/StakeholderProcesses/FlexibleRampingProduct.aspx
[46] The flexible ramping constraint will provide the on-line dispatch capability to efficiently follow net load variations. Using the flexible ramping constraint will reduce the need for CAISO to bias the load forecast in its hour-ahead scheduling process. This capacity will be available for five-minute dispatch in the real-time market. This feature is an important step toward having the flexibility to ensure sufficient ramping capability is available to the CAISO operator as the resource fleet adds more intermittent resources.
[47] http://www.caiso.com/informed/Pages/StakeholderProcesses/CompletedStakeholderProcesses/DynamicTransfers.aspx

- Scheduling updates and forecasting,
- Dispatchability requirements and curtailment rules,
- Locational pricing,
- Aggregating conventional and renewable resources, and
- Multiple dynamic schedules.

Transmission reservation: The existing CAISO tariff establishes a transmission reservation for dynamic schedules that equals CAISO's energy schedules. To ensure that transmission is available for its maximum expected transfer within the hour, the CAISO modification would allow a dynamic transfer to establish transmission reservation for an hour longer than its energy schedules. However, within the hour, a dynamic transfer may be dispatched above or below its transmission reservation, based on available transmission.

Scheduling updates and forecasting: CAISO proposes a scheduling option that will allow dynamic transfers of variable resources to update their expected available energy deliveries within the operating hour. This allows CAISO to manage variability within operating hours and maintain high transmission use by dispatching other resources. In addition, CAISO would require external renewable resources to provide necessary meteorological and telemetry data to develop energy forecasts in a manner similar to internal resources.

Dispatchability requirements and curtailment rules: Dynamically transferred resources must be able to respond immediately to intertie schedule curtailments. Operating procedures will recognize the characteristics of new dynamic resources for this purpose. In addition, this proposal establishes new requirements for compliance with operating orders with consequences uniquely tailored to dynamic transfers. Failure to comply with a CAISO operating order three times will require the resource to install automated equipment to ensure compliance with future operating orders. If no remedy for compliance is installed, the dynamic transfer agreement may be suspended until compliance measures are completed.

Locational pricing: CAISO models generation and dispatchable load at its physical locations and settles energy according to the respective locational marginal prices. This CAISO proposal applies the same principle to dynamic transfers that are associated with specific generation resources.

Aggregation of conventional or renewable resources: CAISO proposes to allow dynamic transfers from an aggregation of resources (conventional and renewable) to offset variation in variable resources' delivery. Within CAISO, aggregation of resources is allowed at the same substation and voltage level to ensure accurate flow modeling within the ISO-controlled grid. For resources outside the CAISO BA, CAISO proposes to allow aggregation within broader geographic areas where the resources have similar impacts on transmission constraints within the CAISO BA. This will also provide an opportunity for companion resource technologies to develop to self-mitigate their variability.

Multiple dynamic schedules: In some instances, generators outside CAISO would like to dynamically schedule into CAISO but cannot obtain a contract for their full capacity on a single external transmission path. CAISO proposes to allow an external generator to be split into separate dynamically scheduled resources, which would be scheduled on different interties.

8.3 Lower Bid Floor

Negative bids serve an important function in the spot markets by allowing resources to indicate their costs for curtailing energy output. Lowering the energy bid floor will provide another incentive for resources to offer flexibility to curtail energy production from previously scheduled levels, and by demand (including exporters) to increase energy purchases when there is excess supply and overgeneration.

The current bid floor level of negative US$30/MWh does not provide a sufficient economic signal for variable renewable resources to curtail output, because such resources often receive additional revenues from outside the CAISO market for their energy production. That revenue prevents these resources from submitting economical decremental bids. Given this constraint, CAISO proposes to move the bid floor in two stages with an effective date of April 1, 2014.[48] First, CAISO will move the bid floor to negative US$150/MWh, then to negative US$300/MWh. CAISO will evaluate the impact of reducing the bid floor to negative US$150/MWh based on a full year's data. If there are no significant, unanticipated negative effects, then CAISO will initiate a stakeholder process to lower the bid floor to negative US$300/MWh and file the appropriate tariff amendments.

8.4 Pay-for-Performance Regulation

FERC issued Order No. 755 on October 20, 2011. This order requires grid operators to compensate frequency regulation[49] resources based on the actual amount of frequency regulation service provided in response to an AGC signal to actual or anticipated frequency deviations or interchange power imbalances. Specifically, Order No. 755 directs ISOs to implement a two-part payment system for frequency regulation service, including the following:

1. A capacity payment that includes the marginal unit's opportunity costs; and
2. A payment for performance that reflects the quantity of frequency regulation service provided by a resource when the resource is accurately following the dispatch signal.

To comply with Order No. 755, CAISO designed the following market enhancements, which were implemented in June 2013:[50]

- The market optimization considers two separately priced components of frequency regulation in determining market awards: (1) regulation capacity, and (2) expected movement in response to the regulation signal (mileage); and
- In addition to a regulation capacity payment, compensation includes a payment based upon a resource's actual movement in response to the regulation signal. This payment will be adjusted based upon the accuracy of the resource's response to the regulation signal.

8.5 FERC 764, Intrahour Scheduling

One of the directives of FERC-approved Order 764 is to remove barriers to the integration of VERs by requiring each Transmission Provider to offer an option to schedule energy with 15-minute granularity.

In connection with its effort to comply with this order, CAISO intends to introduce a 15-minute financially binding settlement within its real-time market that will apply to both intertie and internal resources, as well as load. Under the proposed 15-minute market, energy and ancillary service schedules for internal generation and dynamic and non-dynamic intertie transactions will be financially binding every 15 minutes. Load will also settle in this 15-minute market based on deviations from day-ahead energy schedules and the CAISO forecast. CAISO does not propose any changes to its existing five-minute real-time dispatch (RTD).

[48] http://www.caiso.com/Documents/Sep25_2013TariffAmendment-RenewableIntegrationMarket-ProductReviewPhase1_ER13-2452-000.pdf

[49] Frequency regulation refers to the capability to inject or withdraw real power by resources capable of responding appropriately to a system operator's automatic generator control signal in order to correct for actual or expected ACE needs.

[50] http://www.caiso.com/informed/Pages/StakeholderProcesses/PayforPerformanceRegulation.aspx

The proposal for a 15-minute market would:

- Allow for 15-minute as well as hourly energy scheduling of intertie transactions;
- Address known real-time imbalance energy offset issues due to changes in system conditions between the hour-ahead scheduling process and RTD (five-minute) optimizations;
- Address convergence bidding issues at the interties that result from virtual bids for intertie transactions settling at the hour-ahead scheduling process LMP and internal nodes settling at the RTD LMP; and
- Allow VERs to provide more frequent energy schedules using forecast updates closer to the financially binding interval.

With this proposal, CAISO would no longer award hourly, financially binding energy schedules in the real-time market for intertie transactions. Instead, CAISO would clear and settle intertie energy schedules on a 15-minute basis through the real-time unit commitment process.

8.6 Proposed Enhancements to the CPUC Resource Adequacy Program

In collaboration with the CPUC and other local regulatory authorities, CAISO must ensure that the supply fleet has sufficient flexibility, including ramping and load-following capabilities.[51] This is needed to satisfy ramping and intrahour variability needs, including sufficient contingency reserves to ensure the security and safety of the grid. As the system operator and BA, CAISO has the unique ability to ascertain flexible capacity requirements and the processes and data to perform the needed flexible capacity technical analysis as well. CAISO is currently working with the CPUC and other local regulatory authorities to incorporate flexible capacity requirements into the resource adequacy program.[52] CAISO is also examining alternative capacity procurement structures to ensure sufficient flexible capacity is available to the system.

8.7 Energy Imbalance Market

In February 2013, CAISO and PacifiCorp entered into a memorandum of understanding to create a regional real-time energy imbalance market (EIM)[53] by October 2014. This regional market, which is based on CAISO's March 2012 conceptual proposal, will provide ease of entry for BAs and optimize supply and demand with more precision through five-minute energy dispatch. The benefits of operating an energy imbalance market over multiple BAs include (1) reducing flexibility reserves by aggregating the two systems' load, wind, and solar variability and forecast errors; and (2) reducing renewable energy curtailment by allowing the BA areas to export or reduce imports of renewable generation when that generation would otherwise need to be curtailed. The expanded footprint is expected to provide a low-cost, low-risk means of achieving operational savings for both PacifiCorp and the ISO, enabling greater penetration of VERs. Access to more ancillary services and flexibility from neighboring BAs was a key finding in the NERC IVGTF summary report.

[51] http://www.caiso.com/FASTSearch2/Pages/Results.aspx?k=flexible%20capacity.

[52] On July 3, 2013, the CPUC approved a decision that sets a flexible capacity procurement target for 2014 and adopts a flexible capacity procurement obligation beginning in 2015.

[53] http://www.caiso.com/informed/Pages/StakeholderProcesses/EnergyImbalanceMarket.aspx.

Chapter 9 – Conclusions

This special assessment provides insight into CAISO's approach on renewables integration. A primary conclusion from this review is that when thresholds are reached at the level CAISO is experiencing (i.e., the 20–30 percent level), constraints are experienced on a system that was designed with a different class of equipment in mind. Policymakers should give due consideration to the impacts and potential reduction of essential reliability services (system inertia, frequency and voltage control, power factors, ride-through capability, etc.). The operating characteristics of VERs—not just the energy or capacity being provided—will fundamentally change the basic composition of essential reliability services. The system must continue to work reliably.

As shown by CAISO's actions, there are solutions. Whether through market rules, technology tools, or regulatory requirements, various approaches exist to address concerns. This report offers recommendations and considerations related to standards that are associated with reactive power control, active power control, inertia, and frequency response, as well as steady-state, short-circuit, and dynamic generic model development. Finally, NERC recognizes that the question of "who pays" still exists. If this question is not resolved, it will impede further progress. Integration of VERs cannot be done in a vacuum without full consideration of all approaches.

NERC recognizes CAISO as being at the forefront of VER integration and credits their implementation of various IVGTF recommendations. What works for CAISO may not be the approach taken in another part of North America. There are numerous paths that can be followed, but the full complement of issues should be addressed. NERC offers this report to encourage engagement and raise awareness among policymakers, regulators, and industry so that all may successfully adapt planning and operating processes to manage future integration of VERs and maintain reliability.

Appendix 1: About the NERC-CAISO Joint Report

A1.1 North American Electric Reliability Corporation Background

NERC is a not-for-profit entity whose mission is to ensure the reliability of the bulk power system (BPS) in North America. It develops and enforces Reliability Standards and assesses reliability annually via a 10-year assessment and winter and summer assessments. It also monitors the BPS and educates, trains, and certifies industry personnel. NERC is the electric reliability organization (ERO) for North America and is subject to oversight by the U.S. Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada.[54] NERC develops reliability assessments to inform industry, policy makers, and regulators, and to help accomplish its mission. For additional information, visit the NERC website.[55]

A1.2 California Independent System Operator Corporation Background

The California ISO (CAISO) operates the wholesale transmission grid for a majority of California, providing open and nondiscriminatory access supported by a competitive energy market and comprehensive planning efforts. It is a nonprofit public benefit corporation that partners with over 100 client organizations and is dedicated to the ongoing development and reliable operation of a modern grid. The CAISO bulk power market allocates space on transmission lines, maintains operating reserves, and matches supply with demand. For additional information, visit the CAISO website.[56]

A1.3 NERC–CAISO Assessment

A key purpose of this assessment is to identify real-time operational challenges with high renewable penetration levels and determine if standard development and market changes within CAISO are needed to ensure the power system continues to serve demand reliably, under a range of operating conditions that may arise with the increased penetration of VERs.

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[54] As of June 18, 2007, FERC granted NERC the legal authority to enforce Reliability Standards with all U.S. users, owners, and operators of the bulk power system and made compliance with those standards mandatory and enforceable. NERC presently has memorandums of understanding in place with provincial authorities in Ontario, New Brunswick, Nova Scotia, Québec, and Saskatchewan, and with the Canadian National Energy Board. NERC Reliability Standards are mandatory and enforceable in British Columbia, Ontario, New Brunswick, and Nova Scotia. NERC has an agreement with Manitoba Hydro making Reliability Standards mandatory for that entity, and Manitoba has adopted legislation setting out a framework for standards to become mandatory for users, owners, and operators in the province. In addition, NERC has been designated as the "electric reliability organization" under Alberta's Transportation Regulation, and certain Reliability Standards have been approved in that jurisdiction, while others are pending. NERC and the Northeast Power Coordinating Council have been recognized as standards-setting bodies by the Régie de l'énergie of Québec, and Québec has the framework in place for Reliability Standards to become mandatory and enforceable in that jurisdiction.

[55] www.nerc.com

[56] www.caiso.com

As variable generation resources are connected, the CAISO transmission grid could experience far greater variability from supply resources over the course of minutes to multiple hours. In addition to RPS policies, California is already implementing the Clean Water Act that requires retrofitting certain units with technologies to alleviate related environmental impacts caused by once-through cooling systems. These policies will likely result in some large natural gas steam plants retiring over the next three to five years. Many of these plants provide California's electric system with needed ancillary services, including the ability for generators to ramp in response to significant changes in load, as well as voltage support and inertia necessary for import transfer capability and grid reliability. In addition, Southern California Edison announced in June 2013 that it is permanently shutting down its San Onofre nuclear plant that supplied power to about 1.4 million homes.

Deborah Le Vine, former CAISO director of system operations, noted to FERC in November 2011:[57]

> "NERC should consider examining its portfolio of Reliability Standards during 2012 and 2013 to determine whether there are sufficient tools to allow BAs and Transmission Operators to manage a large volume of intermittent generation. In this respect, NERC should place equal focus on refining existing Reliability Standards as it does on the development of new Reliability Standards."

A1.4 CAISO Market Initiative Description

California's RPS mandates that utilities serve 20 percent of all load from eligible renewable resources[58] between 2012 and 2013. The requirement increases to 25 percent by 2016 and 33 percent by 2020.

CAISO has developed seven guiding principles for assessing the comparative merits of market enhancements that will be used to support the integration of renewable resources:

1. Accommodate new resource types based on their performance capabilities, without preference for specific technologies.
2. Rely on price signals to incentivize participant behaviors that align with CAISO operating needs.
3. Attract robust resource participation.
4. Ensure an efficient mix of resources to maintain reliability and attract new investment when and where needed.
5. Adapt easily to new energy policy goals and a changing resource mix.
6. Leverage CAISO market design to existing CAISO infrastructure, industry experiences, and lessons learned.
7. Allocate costs based on cost causation.

A1.5 NERC's Integration of Variable Generation Task Force

In reaction to the ongoing growth in VERs, NERC's Planning and Operating Committees created the Integration of Variable Generation Task Force (IVGTF)[59] in December 2007. The task force is charged with preparing several reports with the following purposes:

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[57] Prepared Statement of Deborah Le Vine, FERC Docket AD12-1-000: http://www.ferc.gov/EventCalendar/Files/20111208072453-Le%20Vine,%20CAISO.pdf

[58] According to California RPS legislation, renewable resources include wind, solar, geothermal, biomass/biogas, and small conduit hydro.

[59] NERC's Integration of Variable Generation Task Force (IVGTF): http://www.nerc.com/comm/PC/Pages/Integration%20of%20Variable%20Generation%20Task%20Force%20(IVGTF)/Integration-of-Variable-Generation-Task-Force-IVGTF.aspx

1. Raise industry awareness and understanding of variable generation characteristics as well as system planning and operational challenges expected with accommodating large amounts of variable generation.
2. Investigate high-level shortcomings of existing approaches used by system planners and operators, as well as the need for new approaches to plan, design, and operate the power system.
3. Broadly assess NERC Reliability Standards to identify possible gaps and requirements to ensure BPS reliability.

The development of enhanced planning and operational practices will be necessary to reliably integrate VERs into the BPS. These efforts continue in response to several recommendations identified in the 2009 NERC report, *Accommodating High Levels of Variable Generation.*[60] The current focus areas of these efforts are summarized in Table 4.[61]

[60] http://www.nerc.com/files/IVGTF_Report_041609.pdf
[61] The completed reports in Table 4 can be found at: http://www.nerc.com/pa/RAPA/ra/Pages/default.aspx

Table 4: NERC IVGTF Focus Areas

IVGTF Task	Recommendation or Report	Report Status
1. Power system planners must consider the impacts of variable generation in power system planning and design and develop the necessary practices and methods to maintain long-term BPS reliability.		
1.1	Standard Models for Variable Generation	Completed
1.2	Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning	Completed
1.3	Interconnection Requirements for Variable Generation	Completed
1.4	Flexibility Requirements and Potential Metrics for Variable Generation	Completed
1.5	Potential Reliability Impacts of Emerging Flexible Resources	Completed
1.6	Probabilistic Methods for Forecasting Variable Generation	In Development
1.7	Existing BPS voltage ride-through performance requirements and distribution system anti-islanding voltage drop-out requirements of IEEE Standard 1547 must be reconciled.	In Development
1.8	Potential Bulk System Reliability Impacts of Distributed Resources	Completed
2. Operators will require new tools and practices, as well as enhanced NERC Reliability Standards, to maintain BPS reliability.		
2.1	Variable Generation Power Forecasting for Operations	Completed
2.2	Reliability Considerations for BA Communications with Increased Variable Generation	Completed
2.3	Ancillary Service and BA Area Solutions to Integrate Variable Generation	Completed
2.4	Operating Practices, Procedures, and Tools	Completed
3. Planners and operators would benefit from a reference manual that describes the changes required to plan and operate the bulk power and distribution systems to accommodate large amounts of variable generation.		
3.1	NERC should prepare a reference manual to educate bulk power and distribution system planners and operators on reliable integration of large amounts of variable generation.	In Development

As a result of the IVGTF's work over the last four years, several Reliability Standard enhancement opportunities have been identified for consideration. Detailed recommendations can be found in NERC's special assessments included as references in Appendix II of this report.

A1.6 System Flexibility Needs

As new VERs are integrated into the system, resource adequacy and transmission planning processes need to be written with system flexibility requirements in mind. Planning studies have historically concentrated on the concept of adequacy; however, given the variability, emerging operating challenges must also be considered as planning efforts are developed. The IVGTF developed a study approach that:

1. Describes net load characteristics of the system[62] to be served by conventional generation or flexible resources;
2. Documents the experience of power systems that already have a relatively high VER penetration;
3. Identifies sources of flexibility;
4. Discusses metrics that can be used to characterize flexibility; and
5. Discusses the tools required for system planning to include system flexibility and to present conclusions and recommendations.

This information will determine how flexibility could be measured and accounted for in existing studies, whether flexibility should be accounted for differently in planning studies, and what kinds of metrics could be needed to measure flexibility. The report also shows how CAISO is developing these types of measures and instituting procedures to determine flexibility requirements.

Generally, system planning studies have not explicitly addressed the need for system flexibility, because the conventional generating characteristics and performance technologies included well-understood and predictable design requirements to meet the randomness of demand. Power system variability was addressed in resource planning studies by identifying the most economic resource mix to meet a time-varying load profile. In transmission planning studies it was addressed by evaluating loss of resources in local areas. However, for reliable operation, adequate system flexibility is required to accommodate large amounts of VERs. Without this flexibility, VER penetration may be limited to ensure BPS reliability. Therefore, planning and design processes may need to be changed to provide the flexibility needed to meet targeted VER levels. Developing appropriate flexibility metrics is an important aspect in facilitating these new processes.

A report from the IVGTF discusses flexibility characteristics and requirements in detail.[63] In addition to identifying the impact of VERs on the characteristics of system flexibility and their implication for system planning, the report also identifies the many sources of increased flexibility available to system planners and operators. New sources such as demand-side management may be particularly attractive and need further study. Many of the most important sources may not be physical, but institutional (i.e., they unlock the availability of existing physical flexibility, such as forecasting, market design, etc.).

[62] Net Load = Load minus wind production minus solar production.
[63] http://www.nerc.com/files/IVGTF_Task_1_4_Final.pdf

Appendix 2: References

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