

Meeting Renewable Energy Targets in the West at Least Cost: The Integration Challenge

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Executive Summary



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Western Governors' Association

The Integration Challenge

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Western Governors' Association

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Introduction

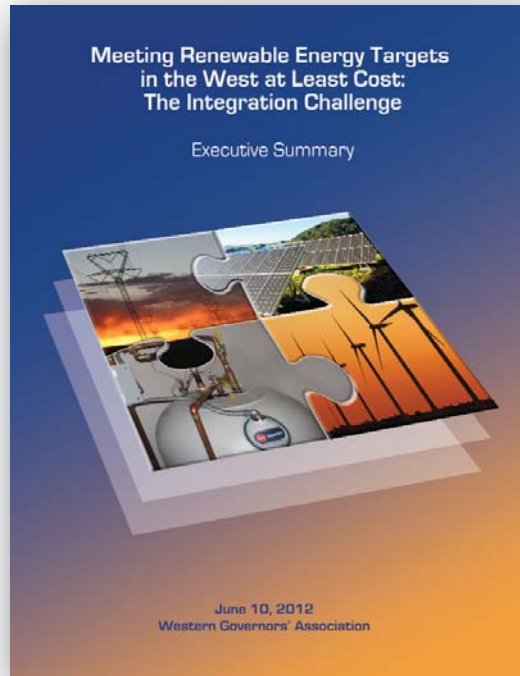
Clean, affordable energy is essential for continued growth of the economy in Western states. State laws and policies put in place in the last decade requiring energy suppliers to bring on-line large amounts of wind and solar generation have changed the traditional mix of “fuels” used for energy generation. By 2022, these policies are expected to more than double the amount of renewable resources in the Western U.S. compared to 2010.

Integrating these resources into a reliable and affordable power system will require an unprecedented level of cooperative action within the electric industry and between the industry and state, subregional and federal entities. Western Governors have encouraged utilities and transmission providers to reduce the cost of integrating renewable energy (see WGA Resolution 10-15). These efforts need to increase as wind and solar resources scale up to help power the Western economy in the future.

Western Governors can help accelerate these efforts by:

- Asking for regular reports from utilities and transmission providers serving their state on actions they are taking to put in place recommendations in this paper;
- Calling for an assessment from the state's utility regulators and energy office on whether an energy imbalance market and faster scheduling of energy and transmission could reduce ratepayer costs and, if so, what is needed to put these practices in place;
- Urging transmission providers and federal power marketing agencies to evaluate the cost and benefits of actions to increase transmission capacity and system flexibility and act on ones that look most promising;
- Directing state agencies to incorporate the recommendations in this report in state energy and transmission plans and economic development initiatives and requesting utilities and regulators to include the recommendations in requirements for utility resource plans and procurement;
- Asking utilities and state agencies to work collaboratively to inventory generating facilities and evaluate future flexibility options to integrate wind and solar resources; and
- Convening parties to discuss benefits to the region from least-cost delivery of wind and solar resources and to develop solutions to address institutional barriers.

The Western Governors' Association commissioned this report to explore ways to reduce costs to the region's electricity consumers for integrating wind and solar, identify barriers to adopting these measures and recommend possible state actions.



The Western U.S. power grid has existing flexibility in the system to cost-effectively integrate wind and solar resources but, as operated today, that flexibility is largely unused. Integration involves managing the variability (the range of expected electricity generation output) and uncertainty (when and how much that generation will change during the day) of energy resources.

Integration is not an issue that is unique to renewable resources; conventional forms of generation also impose integration costs. In fact, most of the measures described in the report would reduce costs and improve the reliability of the grid even if no wind or solar generation is added.

Other regions of the country have found ways to increase flexibility and efficiency from supply- and demand-side resources and transmission, although the West faces some unique challenges including:

- The Western Interconnection is a large area that includes the provinces of Alberta and British Columbia, the northern portion of Baja California, Mexico, and all or portions of 14 Western states.
- It is organized into 37 balancing authorities that operate independent areas within an interconnected grid system.
- Energy and capacity are acquired primarily through utility-built projects and long-term bilateral agreements driven by utility resource plans and procurement processes.
- Outside of organized wholesale markets in Alberta and the California Independent System Operator (CAISO) footprint, subhourly energy transactions are limited.
- Energy is largely delivered on hourly schedules that are fixed shortly before the hour of delivery, with little (or no) ability to make changes.

Drawing from existing studies and experience to date, this report identifies operational and market tools as well as flexible demand- and supply-side resources that can be employed to reduce ratepayer costs for integrating wind and solar in the Western states. The following table provides a high-level overview of the costs and integration benefits for each of these approaches and indicates the level of certainty of these appraisals. The table also provides estimated timeframes for implementation. The remainder of the Executive Summary outlines these approaches and recommendations for states to consider.

Executive Summary

Assessment of Integration Actions

The following table takes a West-wide view of costs and integration benefits of actions described in this report and estimates implementation timeframe. Appendix A describes underlying assumptions. The extent to which any of these actions is undertaken, and therefore its costs and benefits, depend in part on the level of adoption of other actions. However, each action is treated independently here; there is no ranking of options against each other. Colors indicate confidence in the assessment of costs and integration of benefits: blue – high confidence, yellow – medium confidence, and orange – low confidence.

Option	Expected Cost of Implementation ¹ (west-wide except where noted)	Expected Benefit for Integrating Variable Generation	Projected Timeframe in Implementing Option
Subhourly Dispatch and Intra-Hour Scheduling (non-standard, voluntary – not West-wide, 30-minute interval)	Low	Low	Short
Subhourly Dispatch and Intra-Hour Scheduling (standard, voluntary – not West-wide) ²	Low to Medium	Low to Medium	Short
Subhourly Dispatch and Intra-Hour Scheduling (standard, required, West-wide)	Low to High	Medium to High	Medium
Dynamic Transfers (improved tools and operating procedures)	Low	Low to Medium	Short to Medium
Dynamic Transfers (equipment upgrades, including new transmission lines)	Medium to High	Medium to High	Medium to Long
Energy Imbalance Market (subregion only)	Medium to High	Medium	Medium
Energy Imbalance Market (West-wide)	Medium to High	High	Medium to Long
Improve Weather, Wind & Solar Forecasting	Medium	Medium to High	Short to Medium
Geographic Diversity (if using existing transmission)	Low to Medium	Low to Medium	Medium
Geographic Diversity (if new transmission needed)	High	Medium	Long
Reserves Management: Reserves Sharing	Low	Low to Medium	Short
Reserves Management: Dynamic Calculation	Low	Low to Medium	Short
Reserves Management: Using Contingency Reserves for Wind Events	Low to Medium	Low to Medium	Short to Medium
Reserves Management: Controlling Variable Generation (assuming requirements are prospective)	Low to Medium	Low to Medium	Medium to Long
Demand Response: Discretionary Demand	Low to Medium	Low to Medium	Short to Medium
Demand Response: Interruptible Demand	Low to Medium	Low to Medium	Short to Medium
Demand Response: Distributed Energy Storage Appliances	Low to Medium	Low to Medium	Short to Medium
Flexibility of Existing Plants—Minor Retrofits	Low to Medium	Low to Medium	Short to Medium
Flexibility of Existing Plants—Major Retrofits	Medium to High	Medium to High	Medium to Long
Flexibility for New Generating Plants	Low to High	Medium to High	Medium to Long

¹ Low - less than \$10 million region-wide; medium - between \$10 million and \$100 million; high - more than \$100 million.

² Ranges in costs and integration benefits reflect differences in scheduling intervals – 5 to 15 minutes vs. 30 minutes.

Summary of Integration Actions

Expand subhourly dispatch and intra-hour scheduling.

Economic dispatch is the process of maximizing the output of the least-cost generating units in response to changing loads. Scheduling is the advance scheduling of energy on the transmission grid.

Subhourly dispatch refers to changing generator outputs at intervals less than an hour. Intra-hour scheduling refers to changing transmission schedules at intervals less than an hour. In organized energy markets in the U.S., regional system operators dispatch generation at five minute intervals and coordinate transmission with dispatch.

While most transmission in the Western Interconnection is scheduled in hourly intervals, output from variable energy resources changes within the hour. Greater use of subhourly dispatch and intra-hour scheduling in the West's bilateral markets could allow generators to schedule their output over shorter intervals and closer to the scheduling period, effectively accessing existing generator flexibility that is not available to most of the West today. Among other benefits, this would facilitate a large reduction in the amount of regulation reserves needed with significant savings for consumers.

Barriers to achieving these savings in the West include the upfront cost to move from hourly to intra-hourly scheduling; inconsistent practices across areas where intra-hour scheduling is allowed today; the need to synchronize metering, control center operations and software; lack of coordination of intra-hour scheduling with financial settlements; and the lack of a formal, standard market for intra-hour energy transactions outside Alberta and the CAISO footprint.

Recommendations for states to consider:

- Encourage expansion of the Joint Initiative's intra-hour scheduling activities to shorter time intervals.
- Promote expansion of subhourly dispatch and intra-hour scheduling to all entities in the West.
- Foster standardization of intra-hour scheduling among Western balancing authorities, allowing updating of schedules within the hour.
- Evaluate the costs, benefits and impacts of extended pilots on the need for reserves, particularly for regulation.
- Commission an independent analysis of the estimated equipment and labor costs of transitioning to subhourly dispatch and intra-hour scheduling for all transmission providers in the West. Such an analysis also should estimate the benefits, including projected reductions in regulation and other reserve needs, especially for balancing authorities with large amounts of variable energy resources. In addition, the study should evaluate costs and benefits of intra-hour scheduling operations, such as:
 1. two 30-minute schedules both submitted at the top of the hour,
 2. one 30-minute schedule submitted at the top of the hour and another at the bottom of the hour,
 3. 15-minute scheduling and
 4. five-minute scheduling.
- Consider strategies for assisting smaller transmission providers to recover costs of transitioning to intra-hour scheduling, such as coordinated operations among multiple transmission providers or phasing in equipment and personnel upgrades over multiple years.
- Explore harmonized implementation of faster dispatch, scheduling, balancing and settlement across the Western Interconnection.
- Allow regulated utilities to recover costs for wind integration charges assessed by a third party at the lesser of the rate charged for intra-hour scheduling or hourly scheduling, if intra-hour scheduling is an available option. Grant cost recovery for software upgrades and additional staff necessary to accommodate intra-hour scheduling.

Facilitate dynamic transfers between balancing authorities

Dynamic transfer refers to electronically transferring generation from the balancing authority area in which it physically resides to another balancing authority area in real-time. Such transfers allow generation to be located and controlled in a geographic location that is outside of the receiving balancing authority area. Dynamic transfer involves software, communications and agreements and requires the appropriate amount of firm, available transmission capacity between locations.

Dynamic transfers facilitate energy exchanges between balancing authority areas and increase operational efficiency and flexibility. Using dynamic transfers, the within-hour variability and uncertainty of a wind or solar facility can be managed by the balancing authority where the energy is being used. Absent dynamic transfers, that responsibility remains with the balancing authority area where the facility interconnects, even if the plant schedules the power to be sold in another region. Dynamic transfers can result in greater geographic diversity of wind and solar facilities and reduced integration costs and imbalance charges.

For most transmission providers in the Western Interconnection, transmission slated for dynamic transfers must be held open for the maximum dynamic flow that could occur within the scheduling period, typically an hour. Thus, transmission slated for dynamic transfers could displace other potential fixed, hourly transactions on the line. While reservations can be updated in real-time to be used by other market participants, increased dynamic transfers may come at the expense of other uses of the line.

Dynamic transfers also increase intra-hour power and voltage fluctuations on the transmission system that can pose challenges for system operators. The impacts are more difficult to manage as more dynamic transfers have large and frequent ramps within the scheduling period. Lack of automation of some reliability functions is a barrier to increased use of dynamic transfers, as are concerns about the impact on transmission system operating limits.

Recommendations for states to consider:

- Complete transmission provider calculations of dynamic transfer limits to help identify which lines are most receptive, and which are most restrictive for dynamic transfers.
- Determine priority for transmission system improvements to alleviate restrictions on dynamic transfers considering locations for existing and potential renewable generation and balancing resources, and lines needed for dynamic transfers.
- Assess options and costs for additional transmission capacity and additional flexibility on transmission systems to facilitate more widespread use of dynamic transfers. For example, more flexible AC transmission systems can be “tuned” to operate more flexibly. Dynamic line ratings can increase utilization of existing transmission facilities. Also, the impact of lower transmission utilization factors due to dynamic transfers could be minimized through upgrades such as reactive power support and special protection systems.
- Explore use of ramping limits to increase the dynamic transfer capability of certain paths.
- Assess best approaches for integrating dynamic transfer limits into scheduling and operating practices and determine compensation issues.



- Conduct outreach and disseminate information to stakeholders on the implications of dynamic transfer limits and potential system impacts of dynamic scheduling in order to help identify solutions. Dynamic transfer limits may have implications for other mechanisms that can help integrate renewable resources, such as an energy imbalance market and flexible reserves.
- Automate reliability procedures such as voltage control and RAS arming to enable expanded use of dynamic transfers and increase the efficiency of system operations.
- Use near real-time data to calculate system operating limits to address concerns about potential violations of limits due to lack of current data. This could help mitigate restrictive dynamic transfer limits.
- Encourage balancing authorities to use dynamic transfers to aggregate balancing service across their footprints.

Implement an energy imbalance market (EIM)

As proposed for the Western U.S., an EIM is a centralized market mechanism to:

1. re-dispatch generation every five minutes to maintain load and resource balance, addressing generator schedule deviations and load forecast errors and
2. provide congestion management service by re-dispatching generation to relieve grid constraints.

An EIM would increase the efficiency and flexibility of system operations to integrate higher levels of wind and solar resources by enabling dispatch of generation and transmission resources across balancing authorities. That would harness the full diversity of load and generation in a broad geographic area to resolve energy imbalances. An EIM would optimize the dispatch of imbalance energy within transmission constraints, reducing operating costs and reserve needs and making more efficient use of the transmission system. In addition, an EIM would provide reliability benefits by coordinating balancing across the region, making more generation available to system operators.

Among the implementation barriers are upfront financing and accepting and adapting to a new operational practice. Other issues to be resolved include selection of a market operator, governance, a market monitor to prevent and mitigate potential market manipulation, coordination agreements with reserve sharing groups, seams agreements with non-participants and organized market areas, and uncertainty in the level of interest in participation.

Recommendations for states to consider:

- Undertake efforts to define the rates and terms for transmission service agreements for each transmission provider.
- Explore financing options to enable entities to defer some of the startup costs to future years and to better plan and budget for costs.
- Investigate the costs and benefits to ratepayers of regulated utilities participating in an EIM through public utility commission proceedings. Encourage publicly owned utilities to investigate costs and benefits of EIM participation for their consumers. Such evaluations should include potential reduction in integration costs, potential enhanced reliability, changes to compensation for transmission providers and impacts for customers, potential disadvantages of participation, and possible negative economic impacts for meeting renewable energy requirements in the absence of utility participation in an EIM.
- Examine mechanisms for preventing and mitigating potential market manipulation that could reduce benefits.
- Support continuing efforts to explore how governance of an EIM would work, including provisions that address concerns that an EIM could lead to the creation of an RTO.
- Determine the viability of an EIM if major balancing authorities do not participate.
- Provide encouragement and support for the Northwest Power Pool Market Assessment and Coordination Committee which has assembled 20 Western balancing authorities and several other participating utilities to fully evaluate the business case for an EIM.

- Support Western Interconnection-wide efforts to design a proposed EIM for the broadest possible geographic footprint.
- Establish a timeline for implementing the proposed EIM in the West.

Improve weather, wind and solar forecasting

Weather is a primary influence on all electric systems as it drives load demand, in addition to variable generation sources such as wind and solar. Hot days require more power generation to meet demand for cooling, while cold weather requires more generation to serve electric heating requirements. Thus, forecasting of variable generation should be viewed in the broader context of weather forecasting.



Variable generation forecasting uses weather observations, meteorological data, Numerical Weather Prediction models, and statistical analysis to generate estimates of wind and solar output to reduce system reserve needs. Such forecasting also helps grid operators monitor system conditions, schedule or de-commit fuel supplies and power plants in anticipation of changes in

wind and solar generation, and prepare for extreme high and low levels of wind and solar output.

Key barriers to greater use of wind and solar forecasting are deficiencies in forecast accuracy, time required to implement forecasting processes including collection of necessary data, increased need to incorporate variable generation forecasts in day-ahead schedules and dispatch, and lack of updating schedules and dispatch with more accurate forecasts closer to real time. In addition, improvements in the foundational forecasts that variable generation forecasters rely upon will improve the quality and accuracy of variable generation forecasts. Improvements including more frequent measurements and observations, more measurements from the atmosphere, and more rapid refreshing of Numerical Weather Prediction models will improve variable generation forecasting as well as weather forecasting, which have broader benefits for the public, the aviation industry and other users of weather data.

Recommendations for states to consider:

- Support government and private industry efforts to improve the foundational models and data that are incorporated into variable generation forecasting models.
- Encourage the expanded use of variable generation forecasting by balancing authorities.
- Ask balancing authorities that already have implemented variable generation forecasting to study the feasibility and costs and benefits of improvements, such as using multiple forecasting providers or installing additional meteorological towers.
- Study the feasibility and costs and benefits of using variable generation forecasts for day-ahead unit commitments and schedules, including updating schedules closer to real time to take advantage of improved forecast accuracy.

- Consider the feasibility and costs and benefits of more regional variable generation forecasts involving multiple balancing authorities or exchange of forecasts among balancing authorities.
- Ask balancing authorities whether variable generation ramps are of concern now or are expected to be of concern in the future, whether any existing forecasting system adequately predicts ramps in variable generation, and the status of potential adoption of a ramp forecast for variable generation.

Take advantage of geographic diversity of resources

Over a large geographic area, and a corresponding large number of generating facilities, wind and solar projects are less correlated and have less variable output in aggregate. This reduces ramping of conventional generation for balancing, as well as forecasting errors and the need for balancing (not contingency) reserves.



Some regions in the U.S. have large balancing authority areas that naturally provide geographic diversity. Diversity also can be accessed through greater balancing authority cooperation, building transmission and optimized siting of wind and solar plants.

Siting these resources without regard to geographic diversity may have higher costs compared to projects sited to minimize transmission costs. However, if the resource sites are not of equal quality, more wind and solar capacity may be required to achieve the same generation output – at higher cost – compared to developing higher quality resources that are geographically concentrated.

Although the benefits of geographic diversity are generally recognized, there is insufficient information that quantifies the costs and benefits. Further, geographic diversity is typically not factored into transmission planning or resource planning and procurement processes. The question is whether reducing aggregate variability of variable generation through geographic diversity, with the resulting reductions in

reserves requirements and wind and solar forecast errors, justifies initiatives such as transmission expansion. By itself, geographic diversity is probably insufficient to justify new or upgraded transmission lines but it may be an additional benefit. Regardless, the benefits of geographic diversity clearly support balancing authority area aggregation and greater cooperation across areas.

Recommendations for states to consider:

- Quantify the costs and benefits of geographic diversity in utility resource plans and procurement, subregional plans and Interconnection-wide plans. This includes, but is not limited to, siting wind and solar generation to minimize variability of aggregate output and better coincide with utility load profiles.
- Investigate the pros and cons of siting optimization software and whether it can be advantageously used in processes such as defining state and regional renewable energy zones and utility resource planning and procurement to reduce ramping of fossil-fuel generators and minimize reserve requirements.

- Support right-sizing of interstate lines that access renewable resources from regional renewable energy zones designated through a stakeholder-driven process in areas with low environmental conflicts, when it is projected that project benefits will exceed costs. Right-sizing lines means increasing project size, voltage, or both to account for credible future resource needs. Building some level of transmission in advance of need could avoid construction of a second line in the same corridor or minimize the need for additional transmission corridors, and associated environmental disruption, as well as the risk that transmission may not be available to deliver best resources identified in long-term planning.

Improve reserves management

Power system reserves are quantities of generation or demand that are available as needed to maintain electric service reliability. Contingency reserves are for unforeseen events, such as an unscheduled power plant outage. Balancing reserves are for day-to-day balancing of generation and demand.

Higher penetrations of wind and solar resources increase the variability and uncertainty of generation in the system, increasing the need for balancing reserves. These reserves can be managed more efficiently. First, reserve sharing can reduce the requirements of individual balancing authorities by averaging out short-term load and resource fluctuations across a broader area. Second, dynamically calculating regulation and load following reserves would take into account levels of renewable generation (for example, variability of wind plant output changes with output level), load on the system and other system conditions. Third, system operators can work with reliability entities to determine whether contingency reserves could be used for extreme events when wind output drops rapidly. Fourth, relatively modest limits and ramp rate controls for variable generation could significantly reduce the need to hold balancing reserves, at the cost of curtailing some output of renewable energy generation. Automatic generation control for down-regulation also may prove useful if variable generators are compensated for the service.

The first two of these approaches are more proven, while at least some aspects of the latter two approaches are less developed. Among the implementation barriers, additional research and implementation experience are needed in several areas.

Recommendations for states to consider:

- Equip more existing conventional generating facilities with automatic generation control. Experiment with automatic generation control for wind projects and evaluate the benefits to the system against compensating wind generators for lost output.
- Expand reserve-sharing activities such as ADI. Implementation costs are minimal and benefits may be substantial. In addition, ADI programs should consider expanding capacity limits.
- Request the WECC Variable Generation Subcommittee to analyze dynamic reserve methods to help with wind and solar integration.
- Ask balancing authorities to explore calculating reserve requirements on a dynamic basis to take into account the levels of wind and solar on the system and other system conditions.
- Perform statistical analysis to determine the benefits in reduced net reserves that result if balancing reserves for wind and contingency reserves can be at least partially shared. If results are positive, work with NERC and WECC to develop protocols allowing the use of contingency reserves for extreme wind ramping events.
- Develop coordinated or standardized rules for controlling variable generation that minimize economic impacts to wind and solar generators. Controls should be limited to situations where actions are needed to maintain system reliability or when accepting the variable generation leads to excessive costs.
- Consider different wholesale rate designs to encourage more sources of flexibility.

Retool demand response to complement variable supply

Where the fuel that drives a growing share of supply is beyond the control of system operators, as is the case with wind and solar energy, it is valuable to shift load up and down by controlling water heaters, chillers and other energy services. To realize significant integration benefits this must be done through either direct control of the load or pre-programmed responses to real-time prices.

Experience in some regions and results from studies suggest that demand response can be a key component of a low-cost system solution for integrating variable generation. Demand response also provides many other benefits, including increased customer control over bills, more efficient delivery of energy services and a more resilient power system.

Among the barriers, demand response programs that could help integrate variable generation are nascent, advanced metering infrastructure is not in place in many areas, better customer value propositions are needed, and strategies for measuring and verifying demand response must be improved.



Recommendations for states to consider:

- Consider demand response as part of a suite of measures designed and deployed to complement the reliable and cost-effective deployment of larger shares of variable energy resources.
- Further develop and test a range of value propositions to assess customer interest in direct load control and pricing event strategies that support variable generation, with frequent control of loads both up and down.
- Evaluate experience with program designs that pay consumers based on the value of the flexibility services they provide to system operators, with either direct control of selected loads or automated load responses programmed for customers according to their preferences.
- Consider the potential value of enabling demand response programs that can help integrate variable generation when evaluating utility proposals for advanced metering infrastructure.
- Particularly for real-time pricing based programs, cultivate strategies that earn consumer confidence in advanced metering infrastructure and pricing programs, including development of robust policies safeguarding consumer privacy and well-designed consumer education programs.
- Allow and encourage participation of third-party demand response aggregators to accelerate the development of new sources of responsive demand, new consumer value propositions and new service offerings. Address open-source access to demand response infrastructure, access to consumer information, and privacy and data security issues to enable third parties to offer demand response products and services.
- Allow demand response to compete on an equal footing with supply-side alternatives to provide the various services it is capable of delivering. Further, actively accommodate demand response in utility solicitations for capacity.
- Isolate and quantify costs of balancing services to make transparent the value of flexibility options such as demand response.
- Develop robust measurement and verification processes that recognize the unique characteristics of demand-side resources in ways that encourage, rather than discourage, wider participation.
- Examine ratemaking practices for features that discourage cost-effective demand response. Examples include demand charges that penalize (large) customers for higher peak demand levels when they shift load away from periods of limited energy supplies to periods of surplus, and revenue models that tie the utility's profits primarily to volume of energy sales.

Access greater flexibility in the dispatch of existing generating plants

Output control range, ramp rate and accuracy – along with minimum run times, off times and startup times – are the primary characteristics of generating plants that determine how nimbly they can be dispatched by the system operator to complement wind and solar resources. There are economic tradeoffs between plant efficiency, emissions, opportunity costs (the revenue lost when a generator foregoes energy production in order to provide flexibility), capital costs and maintenance expenses.

The best way to achieve the needed generator flexibility is to design and build it into the fleet, selecting technologies that are inherently flexible. Some plants can be retrofitted to increase flexibility by lowering minimum loads, reducing cycling costs and increasing ramp rates. Generators that can reduce output or shut down when wholesale market prices are lower than their operating costs can make more money than generators that have to continue operating at a loss.

Among the barriers to retrofitting plants are the fundamental limitations of the technology, uniqueness of each plant, cost and uncertain payback. The benefits of increasing existing plant flexibility may be comparatively small compared to other ways to reduce integration costs, such as larger balancing authorities and intra-hour scheduling. But the benefits are additive.

Recommendations for states to consider:

First, establish generator scheduling rules that do not block access to the flexibility capability that already exists. Subhourly energy scheduling has proven to be an effective method for maximizing the flexibility of the generation fleet. Second, perform balancing over as large a geographic area as possible. The larger the balancing area, the greater diversity benefit where random up and down movements of loads and variable generators cancel out. Third, design flexibility into each new generator by selecting technologies that are more flexible.

Fourth, retrofit existing generators to increase flexibility when this is practical and cost-effective:

- Analyze the potential for retrofitting existing, less flexible generating facilities. Evaluation on a plant-specific basis is required to determine what additional flexibility, if any, can be obtained through cost-effective modification. It may be possible to achieve faster start-ups, reduce minimum loads, increase ramp rates (up and down), or increase the ability to cycle the generator on and off, or off overnight, and at other times when it is not needed.
- Provide appropriate incentives to encourage generating plant owners to invest in increased flexibility.
- Consider establishing incentives or market options to encourage generators to make their operational flexibility available to system operators.



- Explore development of a flexible ramping ancillary service to take advantage of fast-response capabilities of some types of demand resources and generation.
- Require conventional generators to have frequency response capability or define frequency response as a service that generators can supply for compensation.
- Quantify cycling costs and identify strategies to minimize or avoid cycling.

Focus on flexibility for new generating plants

Traditionally, system operators relied on controlling output of power plants – dispatching them up and down – to follow highly predictable changes in electric loads. Generating plants were scheduled far in advance with only small adjustments in output required to follow changes in demand.

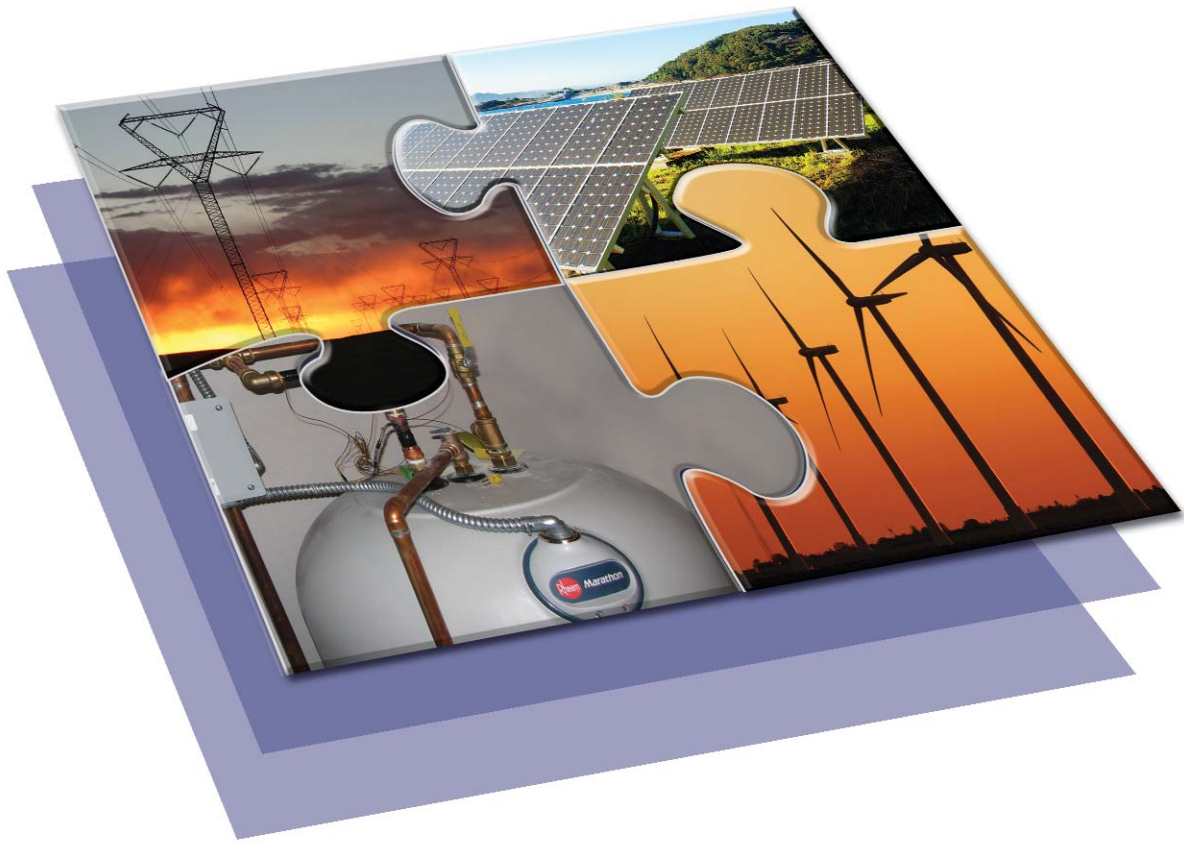
With an increasing share of supply from variable renewable energy resources, grid operators will no longer be able to control a significant portion of generation capacity. At the same time, renewable resources are among the most capital-intensive and lowest cost to operate. Once built, typically the least-cost approach is to run them as much as possible. Therefore, grid operators will need dispatchable generation with more flexible capabilities for following the less predictable “net load” – electricity load after accounting for energy from variable generation.

New dispatchable generation will need to frequently start and stop, change production to quickly ramp output up or down, and operate above and below standard utilization rates without significant loss in operating efficiency. Flexible resources that can meet increased system variability needs with high levels of wind and solar generation will enable more efficient system operation, increased utilization of zero variable-cost resources, and lower overall system operating costs.

A significant challenge is assessing how much flexible capacity already exists and how much will be needed – and when. Resource planning and procurement processes typically are not focused on flexible capability. New metrics and methods are needed to assess flexibility of resource portfolios and resource capabilities needed in the future.

Recommendations for states to consider:

- Retool the traditional approach to resource adequacy and planning analysis to reflect the economic benefit of flexibility service.
- Conduct a flexibility inventory of existing supply- and demand-side resources.
- Evaluate the need for flexible capacity at the utility, balancing authority, subregional and regional levels.
- Examine how utility resource planning and procurement practices evaluate long-term needs, benefits and costs of flexible capacity with increasing levels of variable renewable energy resources, including capabilities and limitations of analytical tools and metrics. Amend planning requirements or guidance to address these needs.
- Review recommendations of NERC’s Integration of Variable Generation Task Force on potential metrics and analytical methods for assessing flexibility from conventional power plants for application in utility resource planning and procurement.
- Examine incentives and disincentives for utilities to invest in flexible supply- and demand-side resources, including those directed at resource adequacy, to meet the growing demand for flexibility services.
- Use competitive procurement processes to evaluate alternative capacity solutions, looking beyond minimum requirements for resource adequacy and analysis focused simply on cost per unit. Specify capabilities, not technologies and fuels, allowing the market to bring the most attractive options.
- Review air pollutant emissions rates allowed under state rules for impacts on procurement of flexible generation, with the aim of maintaining integrity of overall environmental goals.



To access the full report, visit the Western Governors' Association Website at:
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